ANNUAL REPORT

OF THE

NORTH CAROLINA UTILITIES COMMISSION

Regarding Long Range Needs for Expansion of
Electric Generation Facilities
for Service in North Carolina

-November 30, 2010-

November 30, 2010

The Honorable Beverly Perdue
Governor
State of North Carolina
Capitol Building
Raleigh, North Carolina 27611

Dear Governor Perdue:

The North Carolina Utilities Commission hereby presents for your consideration our Annual Report on the Long Range Needs for Expansion of Electric Generation Facilities for Service in North Carolina. We make this report to you and to the members of the Joint Legislative Utility Review Committee of the General Assembly pursuant to G.S. 62-110.1(c).

This report is an update of the information contained in the Commission's last Report, dated December 15, 2009, and is based on reports of the electric utilities serving North Carolina and on the Commission's proceedings in Docket No. E-100, Sub 124, the 2009 Integrated Resource Planning docket. The section on generation resources contains the latest information received from the utilities.

Sincerely,

Edward S. Finley, Jr.
Chairman

ESFjr/RWE/kah

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Western Carolina University

North Carolina Electric Membership Corporation

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LIST OF ACRONYMS

AP = Advanced Passive
ARRA 2009 = American Recovery and Reinvestment Act of 2009
Blue Ridge = Blue Ridge EMC
CC = combined-cycle
COD = commercial operating 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
ERO = Electric Reliability Organization
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 WARN = North Carolina Waste Awareness and Reduction Network, Inc.
NC-RETS = North Carolina Renewable Energy Tracking System
NCEMC = North Carolina Electric Membership Corporation
NCEMPA = North Carolina Eastern Municipal Power Agency

LIST OF 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
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
VACAR = Virginia and Carolinas Regional Reliability Council
VEPCO = Virginia Electric and Power Company
WPSA = Wholesale Power Supply Agreement

TABLE OF CONTENTS

APPENDICES

1. EXECUTIVE SUMMARY

This annual report to the Governor and the General Assembly is submitted pursuant to General Statute (G.S.) 62-110.1(c), which specifies that each year the North Carolina Utilities Commission shall submit to the Governor and appropriate committees of the General Assembly a report of its analysis of the long-range needs for the expansion of facilities for the generation of electricity in North Carolina and a report on its plan for meeting those needs. Much of the information contained in this report is based on reports to the Commission by the electric utilities regarding their respective 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 17% of the IOUs' 2009 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)	
	2009	2008	2009	2008	2009	2008
Progress	36,694	37,244	13,471	13,803	56,947	58,116
Duke	54,348	55,752	4,902	6,177	79,830	85,476
NC Power (VEPCO)	4,029	4,211	707	514	81,513	84,026

*GWh = 1 Million kWh (kilowatt-hours)

During the 2010 to 2024 timeframe, the average annual growth rate in summer peak demand for electricity in North Carolina is forecasted to be approximately 1.8%. Table ES-2 illustrates the systemwide average annual rates of growth 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) (2010 – 2024)

	Summer Peak	Winter Peak	Energy Sales
Progress	1.6%	1.8%	1.4%
Duke	1.8%	1.5%	1.6%
NC Power	2.0%	1.8%	2.2%

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 2009

	Progress	Duke	NC Power
Coal	46%	43%	33%
Nuclear	41%	51%	32%
Net Hydroelectric*	1%	2%	0%
Oil and Natural Gas	6%	0%	9%
Wood/Biomass	0%	0%	1%
Purchased Power	6%	4%	25%

* See discussion of pumped storage in Section 6.

Current reliability assessments by the North American Electric Reliability Corporation (NERC) continue to project that the Southeastern region will have adequate generation reserve margins over the next ten years. Progress, Duke, and NC Power are projecting reserve margins that are typical for electric utilities serving the Southeastern states and similar to the reserve margins that they have maintained in the recent past.

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 December 15, 2009 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 124, Investigation of Integrated Resource Planning in North Carolina - 2009.

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, 2009, Duke had 1,838,000 customers located in North Carolina, and Progress had 1,289,000. 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 17% 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 2009 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)	
	2009	2008	2009	2008	2009	2008
Progress	36,694	37,244	13,471	13,803	56,947	58,116
Duke	54,348	55,752	4,902	6,177	79,830	85,476
NC Power (VEPCO)	4,029	4,211	707	514	81,513	84,026

*GWh = 1 Million kWh (kilowatt-hours)

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 989,000 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. Load data for NCEMC is shown in Appendix 5.

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.

NCEMC's peak load growth is projected to be approximately 1.6% per year during the 2010-2024 summer seasons. NCEMC owns approximately 722 megawatts (MW) of generation resources, consisting of 704 MW from Duke's Catawba Nuclear Station plus 18 MW from two small diesel-powered peaking plants (at Ocracoke and Buxton Stations) on the Outer Banks. Additionally, most EMCs receive an allocation of hydroelectric power from the Southeastern Power Administration (SEPA).

Exercising their right to cease full participation in NCEMC's power supply program, five members of NCEMC have given 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.

As of 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 6, 7, 8, and 9.

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 can be obtained, NCEMC's ultimate goal is to serve all its members as a single integrated system. In the spring of 2004, NCEMC decided to build 620 MW of combustion turbine generation divided among two sites (338 MW in Anson County and 282 MW in Richmond County). The Anson County facility began commercial operation on June 1, 2007. The Richmond County plant commenced commercial operation on December 1, 2007. In addition, on August 25, 2010, NCEMC was granted a Certificate of Public Convenience and Necessity (CPCN) to construct a 56 MW combustion turbine generator at its existing Richmond County site.

NCEMC currently purchases wholesale electricity from Progress, Duke, Dominion, American Electric Power, South Carolina Electric & Gas (SCE&G), and SEPA. It has executed two contracts with Southern Power to purchase additional capacity and energy beginning in 2012. 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 has also entered into two wholesale power sales commitments. In one, NCEMC and Progress executed a Tolling Agreement whereby NCEMC will toll the output of NCEMC's Anson facility to Progress starting on January 1, 2013 through December 31, 2032. Under this agreement, NCEMC owns and maintains the Anson facility for the exclusive use of meeting Progress's dispatch requests. 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 executed a sale agreement. Under this agreement NCEMC will sell 100 MW of power to Southern Power. This sale starts on January 1, 2012 and ends on December 31, 2021.

Like the IOUs, NCEMC is a member of the Virginia and Carolinas Regional Reliability Council (VACAR), a sub-region of the Southeastern Electric Reliability Corporation (SERC), and participates on several committees. NCEMC also participates in and closely monitors activities related to regional transmission organizations (RTOs) and is a member of the PJM Interconnection, LLC (PJM), which is discussed later in this report. NCEMC notes that these efforts are particularly important to it because of NCEMC's status as a transmission-dependent utility that relies on Duke, Progress, and NC Power/PJM to transmit the power it generates and purchases to its load.

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 are subject to 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 (696 MW of coal and nuclear capacity). NCEMPA has a Supplemental Load Agreement with Progress that runs through 2017. The contract provides for additional power when needs 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 72 MW of generation owned by municipalities and retail customers which is available during times of high demand and spiking wholesale prices. During 2009, NCMPA1 completed construction of two gas turbine generators in Monroe that will 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 five North Carolina counties and serve over 32,000 households and 8,600 commercial and industrial customers. The North Carolina counties served by distributors of TVA power are Avery, Burke, Cherokee, Clay, and Watauga.

TVA owns and operates four hydroelectric dams in North Carolina with a combined generation capacity of 532 MW. The dams are Appalachia and Hiwassee in Cherokee County, Chatuge in Clay County, and Fontana in Swain and Graham counties. TVA owns and/or maintains six substations and switchyards and 115 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(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 additional 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.

2009 IRP Proceeding (Docket No. E-100, Sub 124)

The 2009 annual updates to the 2008 biennial IRPs (2009 update reports) were filed in Docket No. E-100, Sub 124 by Progress, Duke, NC Power, NCEMC, Piedmont, Rutherford, EnergyUnited, and Haywood. Blue Ridge had previously entered into a full requirements power purchase agreement with Duke whereby the entire Blue Ridge load is now included in Duke's IRP. Also, the 2009 Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance plans were submitted by the electric utilities, GreenCo Solutions, Inc. (GreenCo)[1], Halifax, and EnergyUnited.

The 2009 updates to the 2008 biennial reports superseded much of the information contained in the 2008 reports. Because these reports complete a two-year reporting cycle, the Commission decided to consolidate the 2008 and 2009 IRP dockets for

[1] GreenCo filed a consolidated REPS compliance plan on behalf of its members: Albemarle EMC, Brunswick EMC, Cape Hatteras EMC, Craven-Carteret EMC, Central EMC, Edgecombe-Martin 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 Power Cooperative, and Wake EMC.

purposes of decision. In addition, because of the great interest regarding many of the IRP issues as they affect the investor-owned public utilities in particular, the Commission found good cause to schedule an evidentiary hearing for March 16, 2010, to consider the 2009 IRPs and REPS compliance plans filed by Progress, Duke, and NC Power.[2] This procedure superseded and replaced the normal comment process specified by Commission Rule R8-60(j) for the 2009 IRPs filed by the investor-owned public utilities. Furthermore, as to the 2008 IRPs filed by the investor-owned public utilities, the Commission saw no need for an evidentiary hearing on those plans in view of the fact that interested parties had previously filed comments in Docket No. E-100, Sub 118. The 2009 IRPs filed by the non-IOU utilities were addressed through the normal comments process as contained in Rule R8-60(j). After the hearing and the filing of proposed orders and briefs, the Commission issued its Order Approving Integrated Resource Plans and REPS Compliance Plans in the consolidated dockets.

A copy of the Order, dated August 10, 2010, is included in this report as Appendix 1.

5. LOAD FORECASTS AND PEAK DEMAND

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

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

Table 2 illustrates the systemwide average annual growth rates in energy sales and peak loads anticipated by Progress, Duke, and NC Power. These growth rates are based on the utilities' system peak load requirements. Detailed load projections for the respective utilities are shown in Appendices 2, 3, and 4. Under normal weather patterns, the annual summer peak demand remains higher than the winter peak demand for the three IOUs serving North Carolina.

[2] This action largely rendered moot a Motion for Reconsideration and Renewal of Request for Hearing filed by the North Carolina Waste Awareness and Reduction Network, Inc. (NC WARN) in the 2008 IRP docket on August 12, 2009.

Table 2: Forecast Annual Growth Rates for Progress, Duke, and NC Power (After Energy Efficiency and Demand-Side Management are Included) (2010 – 2024)

	Summer Peak	Winter Peak	Energy Sales
Progress	1.6%	1.8%	1.4%
Duke	1.8%	1.5%	1.6%
NC Power	2.0%	1.8%	2.2%

North Carolina utility forecasts of future peak demand growth rates are somewhat similar to forecasts for the nation as a whole. The 2009-2018 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 1.5% to 1.6%. This number is slightly lower than that shown in NERC's prior year report.

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 2005 (in MW)

	Progress		Duke		NC Power	
	Summer	Winter*	Summer	Winter*	Summer	Winter*
2005	12,572	10,685	18,687	14,372	17,007	13,063
2006	12,493	12,138	17,906	16,196	17,244	16,090
2007	12,656	11,991	18,988	16,460	17,158	15,316
2008	12,290	11,832	18,228	16,968	16,955	15,775
2009	11,796	12,531	17,397	17,282	18,137	17,612

**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, and hydro) 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, combustion turbines and other peaking plants usually operate less than 1,000 hours per year.

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

Progress has four nuclear units divided among three locations. Two of the locations are in North Carolina. The Brunswick facility, near Southport, has two units and the Harris Plant, near New Hill, has one unit. The Robinson facility also has one unit and it is located in South Carolina. The NRC has renewed the operating licenses for Brunswick Units 1 and 2 until 2036 and 2034, respectively. The Robinson license has been renewed to 2030 and the Harris license was extended 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 owned by each IOU is shown in Table 4.

Table 4: Installed Utility-Owned Generating Capacity by Fuel Type (Summer Ratings) for 2009

	Progress	Duke	NC Power
Coal	41%	37%	29%
Nuclear	28%	33%	19%
Hydroelectric	2%	15%	13%
Oil and Natural Gas	29%	15%	38%
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 2009, is provided in Table 5.

Table 5: Total Energy Resources by Fuel Type for 2009

	Progress	Duke	NC Power
Coal	46%	43%	33%
Nuclear	41%	51%	32%
Net Hydroelectric*	1%	2%	0%
Oil and Natural Gas	6%	0%	9%
Wood/Biomass	0%	0%	1%
Purchased Power	6%	4%	25%

* 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 percentage of generation (MWh) from coal and nuclear units typically exceeds the percentage of generating capacity (MW) represented by such units, reflecting the use of these units for baseload generation. On the other hand, oil- and natural gas-fired combustion turbine units usually contribute a small amount of actual generation, although they represent a significant percentage of the generating capacity available to each utility, reflecting the use of combustion turbines primarily for peak-load generation and standby capacity.

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 2010, Progress had 12,585 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 2010 resource plan proposes to add 5,046 MW of new capacity during the 2011-2025 period. This includes the 635 MW of combined-cycle (CC) natural gas generation at the Company’s Richmond County facility scheduled to go into service in mid-2011 and 920 MW of CC generation in Wayne County with an expected in-service date of early 2013. A nuclear baseload addition of 550 MW (25% ownership in two units through a regional partnership) is shown in the 2020/2021 timeframe, which is significantly less than the two full units (2210 MW) included in the 2009 resource plan. In addition, approximately 100 MW of planned uprates to existing facilities are projected by 2015.

On December 18, 2009, in Docket No. E-2, Sub 968, Progress filed an application for a CPCN to construct approximately 620 MW of CC generation in New Hanover County. This construction was approved by a Commission Order dated June 9, 2010, which is included as Appendix 10 in the back of this report.

Currently, Progress is planning to retire 11 existing coal units at the Company's Lee, Sutton, Weatherspoon, and Cape Fear Sites in North Carolina between early 2013 and late 2014. These units total 1500 MW. The exact dates of these retirements may change subject to a number of variables.

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. The NRC estimated that it will take approximately three to four years to review and process the COL application. According to its 2010 IRP report, if Progress receives approval from the NRC and applicable state agencies, and if the decisions to build are made, Progress would not have any new nuclear generation online until at least 2019.

Duke Generation

As of September 2010, Duke had 20,926 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
In March 2007, Duke received a CPCN for the 825 MW Cliffside 6 unit, which is scheduled to be online in 2012. As of June 2010, the project was over 68% complete.

Bridgewater Hydro Powerhouse Upgrade
The two existing 11.5 MW units at the Bridgewater Hydro Station are being replaced by two 15 MW units and a small 1.5 MW unit to be used to meet continuous release requirements. It is scheduled to be available for the summer peak of 2012.

Jocassee Unit 1 and 2 Upgrades
Capacity additions reflect an estimated 50 MW capacity up-rate at the Jocassee pumped storage facility from increased efficiency from new equipment to be installed in 2011.

Belews Creek Rotor Upgrade
A Belews Creek rotor upgrade was completed on Unit 1 in 2009 and on Unit 2 in the spring of 2010. The station is currently evaluating the efficiency gains based on summertime operation prior to reflecting increased capacity gains.

Buck CC Natural Gas Unit
A CPCN was received in June of 2008 and the air permit was received in October of 2008. The 620 MW Buck CC unit is scheduled to be operational by the end of 2011 and available by the summer of 2012. Construction is underway and the project is currently over 20% complete.

Dan River CC Natural Gas Unit
A CPCN for the 620 MW CC unit was received in June of 2008 and the air permit was received in August of 2009. Activities to date include major equipment delivery and site preparation. Project construction is scheduled to begin the first quarter of 2011 and the unit is scheduled to be operational by the end of 2012.

Riverbend, Buck, Dan River, and Buzzard's Roost Combustion Turbine (CT) Derates
Available system capacity is reviewed every spring. In the 2009 review there were multiple de-rates among the old fleet at Buck, Dan River, and Riverbend totaling 124 MW. Additional de-rates were identified during the 2010 review at the Buzzard's Roost station totaling 20 MW. These turbines were installed in the late 1960's and early 1970's and are approaching end of life, with increasing difficulty in finding parts required for optimal operation.

Lee Steam Station Natural Gas Conversion
The Lee Steam Station in South Carolina 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 at an alternative site. For planning purposes the Lee Steam Station will be retired as a coal station during the fourth quarter of 2014 and converted to natural gas by January 1, 2015. Preliminary engineering has been completed and more detailed project development and regulatory efforts will begin in 2011.

In addition, Duke is projecting the possible need for 740 MW of new CT generation in both 2017 and 2019. It is also considering nuclear uprates of 205 MW from 2012 to 2019, plus the possible addition of 2,234 MW of new nuclear capacity as discussed below.

Duke currently forecasts the possible retirement of up to 2,037 MW of capacity between 2011 and 2015. Over 1,650 MW of this total is made up of conventional coal-fired units. The remainder is made up of older CT units at multiple locations. 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.

There are two specific requirements that are related to the retirement of 800 MW of the older coal units. The first, a condition set forth in the Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6, requires the retirement of existing Cliffside Units 1-4 (200 MW) no later than the commercial operation date of the new unit, and retirement of older coal-fired generating units (in addition to Cliffside Units 1-4) on a MW-for-MW basis, considering the impact on the reliability of the system, to account for actual load reductions realized from new energy efficiency (EE) and demand-side management (DSM) programs up to the MW level added by the new Cliffside Unit. The requirement to retire older coal units is also set forth in the air permit for the new Cliffside Unit. In addition to Cliffside Units 1-4, it requires the retirement of 350 MW of coal generation by 2015, an additional 200 MW by 2016, and an additional 250 MW by 2018. If the Commission determines that the scheduled retirement of any unit identified for retirement pursuant to Duke's retirement plan will have a material adverse impact on the reliability of the electric generating system, Duke may seek modification of this plan. For planning purposes, the retirement dates for these 800 MW of older coal units are associated with the expected verification of realized EE load reductions, which is expected to occur earlier than the retirement dates set forth in the air permit.

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. Site characterization work is complete. In December, 2007, Duke submitted its COL application to the NRC for the proposed Lee Nuclear Station.

At the present time, Duke states that it is considering the option for new nuclear generating capacity in the 2020 timeframe. Duke continues to pursue project development and appropriate recovery and to evaluate the optimal time to file a CPCN in South Carolina and other needed 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 will also 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 2010, NC Power had 16,461 MW of existing Company owned generating capacity (summer rating). This excludes purchases and non-utility capacity.

In April 2009, Ladysmith Unit 5, a 160 MW CT unit became operational at the Company's existing Ladysmith Power Station in Carolina County, Virginia. Currently under construction in Buckingham County, Virginia, is the 590 MW Bear Garden CC facility with a forecasted commercial operating date (COD) of 2011, and a 585 MW coal/biomass station at the Virginia City Hybrid Energy Center in Wise County, Virginia, with a targeted COD of 2012. In addition, planned modifications to existing facilities between 2011 and 2015 will result in a net addition of 207 MW of new capacity, including an additional 159 MW at existing nuclear plants.

The Warren County CC plant and North Anna 3 nuclear facility, discussed below, are currently under development or in the early stages of the development process of planning, permitting, and approval. No final decision can be made to build either of these resources until they have been approved by regulators.

The Warren County CC plant is being developed in the northwest area of Virginia. For modeling purposes, it has been rated at 1,082 MW; however, the final rating will be determined after the design and vendor selection have been completed. Based on the current schedule, this plant would be available to meet 2015 peak capacity and energy demand.

Nuclear power is a critical component of NC Power's plan to achieve fuel diversity, stable long-term customer electric rates, and low emissions. The North Anna 3 facility would provide up to 1,268 MW of baseload capacity to the region by 2019. Although the Company has not committed to build this new unit, it intends to maintain the option to do so to meet projected demand and energy requirements for electricity.

On November 27, 2007, the NRC issued an Early Site Permit to the Company's affiliate, Dominion Nuclear North Anna, LLC, for a site located at the Company's existing North Anna Power Station. 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 Early Site Permit to the Company and ODEC. A merger of Dominion Nuclear North Anna, LLC into the Company was effective December 1, 2008.

In March 2009, the company issued a Request for Proposals (RFP) to license, engineer, procure, and construct the new nuclear unit at the North Anna Power Station. NC Power selected Mitsubishi Heavy Industry's US-APWR for the design of the planned nuclear unit, although no Engineering, Procurement, and Construction 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.

Between 2011 and 2015, NC Power may retire 21 units (273 MW) of older CT generation. This group includes the two units (31 MW) at Kitty Hawk that began operation in 1971. Those two units have a potential retirement date of 2011. Prior to the actual retirement of any of these older 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 2, 3, and 4. The summer reserve margins currently projected by each IOU are illustrated in Table 6.

Table 6: Projected Reserves for Progress, Duke, and NC Power (2010-2024)

	Reserve Margins
Progress	13% – 25%
Duke	16.9% – 22.4%
NC Power	12.0% – 17.4%

For many years, it has been a federal policy to encourage interconnection and coordination among electric utilities in order to conserve energy, make more efficient use of facilities and resources, and increase reliability. The North American Electric Reliability Corporation, or NERC, was formed by the electric power industry in 1968 to promote the reliability of bulk electric power supply in North America. NERC consists of eight regional areas, which together encompass virtually all of the electric power systems in the United States and Canada.

Prior to 2007, NERC, a not-for-profit corporation, relied on voluntary efforts and what it referred to as "peer pressure" to ensure compliance with reliability standards, but this approach was widely considered inadequate. NERC observed that the blackout of August 14, 2003, clearly demonstrated that the existing scheme of voluntary compliance with industry-developed reliability rules was no longer adequate in a restructured industry. To ensure the continued reliability of the interconnected transmission grid, reliability rules needed to be mandatory and enforceable and applied fairly to all electric industry participants throughout North America. Changing from a strictly voluntary reliability system to a mandatory, enforceable one required federal legislation authorizing the establishment of an independent electric reliability organization. On August 8, 2005, federal reliability legislation that had support from a wide array of interested parties took effect in the United States, establishing the foundation for making reliability standards mandatory and enforceable.

NERC worked closely with industry stakeholders and the Federal Energy Regulatory Commission (FERC) to become recognized as the official Electric Reliability Organization (ERO). On July 20, 2006, the FERC approved NERC's application to become the ERO for the United States. As of June 18, 2007, the FERC granted NERC the legal authority to enforce reliability standards with all U.S. owners, operators, and users of the bulk power system and made compliance with those standards mandatory and enforceable, as opposed to voluntary. It will audit owners, operators, and users for preparedness and educate and train industry personnel. NERC is a self-regulatory organization which is subject to audit by the FERC.

The Southeastern Electric Reliability Corporation, or SERC, is one of the eight NERC regional reliability organizations. Its 63 members include investor-owned utilities, electric cooperatives, municipally-owned utilities, RTOs, federal and state-owned systems, independent power producers, and power marketers. SERC is divided into five subregions and covers portions of 16 southeastern and central states. The five subregions are: Central, Delta, Gateway, Southeastern, and VACAR. SERC and its five subregions are all summer peaking. VACAR, which stands for Virginia Carolinas, consists of the Progress, Duke, and NC Power operating areas, in addition to the operating areas of other utilities serving portions of Virginia, North Carolina, and South Carolina.

The NERC October 2009 Long-Term Reliability Assessment indicates that the summer reserve margins for the SERC region will be adequate during the 2009-2018 period. NERC also projects that SERC will have adequate capacity resources during that period. Over the next ten years, the average annual summer peak demand growth rate for the entire SERC area is forecast to be 1.8%, which is slightly below last year's 1.9% forecast. The average annual demand growth rate for the VACAR sub-region during this period is also forecast to be 1.8%. These forecasts are based on average weather conditions.

While coal and nuclear 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. Often favored for their 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

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 must assure 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 October 1, 2010, the Commission submitted its third annual report to the Governor, the Environmental Review Commission, and the Joint Legislative Utility Review

Committee regarding Commission implementation of, and electric power supplier compliance with, the REPS. In addition, on October 1, 2009, the Commission filed its first 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 RECs. In 2008 the Commission opened Docket No. E-100, Sub 121 and established a stakeholder process to propose requirements for a North Carolina Renewable Energy Tracking System (NC-RETS). On October 19, 2009, the Commission issued a request for proposals via which it selected a vendor, APX Inc., to design, build, and operate the tracking system. NC-RETS began operating July 1, 2010, consistent with the requirements of Session Law 2009-475.

At the end of 2010, each electric power supplier will place solar RECS that they acquired to meet their 2010 REPS solar set-aside obligation into a 2010 compliance account within NC-RETS, which account will be available for audit. When the Commission concludes its review of each electric power suppliers' REPS compliance report, the associated RECs will be permanently retired.

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 November 9, 2010:

- NC-RETS had issued 665,080 RECs and 1,215 energy efficiency certificates.
- 96 organizations, including electric power suppliers and owners of renewable energy facilities, had established accounts in NC-RETS.
- About 93 renewable energy facilities had been established as NC-RETS projects, enabling the issuance of RECs based on their energy production data.

Energy Efficiency

Electric power suppliers in North Carolina are required to implement DSM and 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 and VEPCO have filed for the approval of a number of energy efficiency measures and cost recovery. VEPCO's requests are still pending before the Commission, as is Progress's most recent DSM/EE cost recovery request. EnergyUnited in 2009 filed for and received approval of two energy efficiency programs. In 2010, GreenCo filed for and received approval for ten EE programs.

On September 1, 2009, the Commission filed its first biennial report to the Governor and the Joint Legislative Utility Review Committee regarding proceedings for electric utilities involving EE and DSM cost recovery and incentives. That report provides a comprehensive review of the Commission's activities regarding EE and DSM, and is available on the Commission's web site.

NC GreenPower

NC GreenPower is an independent, nonprofit organization and the first, statewide multi-utility renewable energy program in the nation. Established in 2003, this landmark program launched an opportunity for North Carolinians to voluntarily support the growth of green power in North Carolina. As of 2008, NC GreenPower also offered Carbon Offsets to address growing concerns about the impact of greenhouse gases on the environment.

NC GreenPower is a statewide program designed to improve the quality of the environment by encouraging the development of renewable energy resources through consumers' voluntary funding of green power purchases by electric utilities in North Carolina and the mitigation of greenhouse gas emissions through consumers' voluntary funding of Carbon Offsets. The program revenues help provide financial incentives for generators of electricity from renewable sources and for developers of projects mitigating greenhouse gas emissions.

As of November 2010, NC GreenPower has contracts with the following green power generators: 369 solar photovoltaic (PV), two small hydroelectric, six wind, and one landfill methane. As of September 30, 2010, 12,221 North Carolina electric consumers were subscribed to 24,679 100-kWh blocks of power per month – representing 29,614,806 kWh of renewable energy to be delivered to the electric grid in North Carolina this year, which is enough to power about 2,500 homes. The Carbon Offset program currently has 384 customers subscribed to 973 blocks of greenhouse gas mitigation (500 pounds each), representing a total annual offset of 5,838,000 pounds of carbon dioxide equivalent. These donations are the environmental equivalent of planting 5,189,471 trees.

More than 48 utilities across North Carolina assist NC GreenPower by providing billing and collection of donations through consumers' utility bills.

9. TRANSMISSION AND GENERATION INTERCONNECTION ISSUES

Transmission Planning

The North Carolina Transmission Planning Collaborative (NCTPC) was established in 2005 and issued its first report in January of 2007. In that report, participants (transmission-owning utilities, such as Duke and Progress, and transmission-dependent utilities, such as municipal electric systems and EMCs) identified the electric transmission projects that needed to be built for reliability and estimated the costs of those upgrades.

The NCTPC's January 2010 report states that 18 major transmission projects are needed in North Carolina by the end of 2019 at an estimated cost of $595 million. In 2010, the NCTPC studied the transmission that would be needed to accommodate 3,000 MW of wind generation if it were built off the shores of North Carolina. The final report on this question, as well as an update of the NCTPC's 2010 study, will be published in early 2011. Pursuant to G.S. 62-101, a certificate of environmental compatibility and public convenience and necessity from the Utilities Commission is needed before building a transmission line of 161 kilovolts or more in size. No such requests are currently pending before the Commission. However, on March 31, 2010, the Citizens to Protect Kituwah Valley and Swain County jointly filed a complaint against Duke. The complaint asserts that Duke should be required to obtain a certificate of public convenience and necessity prior to building a 161-kilovolts transmission line, even though the line would replace an existing smaller line in the same location. The complaint is pending before the Commission (Docket No. E-7, Sub 949).

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.

Finally, 2010 saw the creation of a new organization 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. The DOE approved the award 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 that should assist the states in reaching consensus regarding future sources of electric energy, and by extension, the new electric transmission infrastructure needed to move that energy to consumers.

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 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 by 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 open access transmission tariffs (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

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).

Open Access Transmission Tariff Reform

On February 16, 2007, the FERC issued Order No. 890, adopting changes to the pro-forma 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.

The FERC currently has an open 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 have intervened in this proceeding, representing North Carolina electricity consumers.

Transmission Rate Filings

In 2008, NC Power sought permission from the FERC to charge transmission customers an incentive return on equity (ROE) for specific transmission construction projects. The Commission intervened in that case, arguing that a higher ROE would be inappropriate for some of NC Power's proposed projects and would unreasonably increase electricity prices to customers. The FERC rejected the Commission's arguments and granted NC Power's full request on August 29, 2008. The Commission has filed a request for reconsideration of this decision, which is pending. While the Commission retains full jurisdiction over NC Power's retail prices in North Carolina, NC Power's proposal would increase its wholesale transmission rates and, thus, impact the cost of importing power to other electric consumers in North Carolina.

In 2010, the Commission and the Public Staff jointly intervened in another NC Power transmission rate case before the FERC, again arguing that some transmission costs should not be passed onto 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 electric transmission lines when a viable overhead option was available. That case is now the subject of settlement negotiations.

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 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.

In October 2007, DOE issued an order designating two national interest electric transmission corridors. The Mid-Atlantic Area National Corridor includes portions of Delaware, Maryland, New Jersey, New York, Ohio, Pennsylvania, Virginia, West Virginia, and Washington, D.C. The Southwest Area National Corridor includes portions of southern California and western Arizona. DOE is required to prepare a report to Congress every three years on the status of transmission congestion nationwide. DOE’s 2010 report has not yet been issued.

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. As discussed above, 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.

American Recovery and Reinvestment Act of 2009 (ARRA 2009)

The ARRA 2009 initiated numerous efforts intended to stimulate the economy and create jobs. Many of them relate to energy infrastructure and energy policy. As authorized by the ARRA, the DOE announced a funding opportunity in mid-June of 2009 whereby it solicited grant proposals for "State Electricity Regulators Assistance." The intent of the grants is to insure that state regulators can meet the increased workload anticipated due to other ARRA awards such as those related to energy efficiency, renewable energy, energy storage, smart grid, electric and hybrid-electric vehicles, demand-response, coal with carbon capture and storage, and electric transmission. The Commission responded with a grant request to DOE, which was approved in September of 2009. The Commission requested funding for an electricity specialist position, which was filled by a new employee on October 15, 2010. This full-time position is limited to the four-year term of the grant. The grant will also cover the costs of training to prepare staff and commissioners to better address complex electric energy issues. The Commission and staff have subsequently attended several training meetings on topics that are eligible for ARRA funding.

The DOE also made ARRA grant awards to electric utilities for proposals related to smart grid. Progress and Duke were both grant recipients.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 118
DOCKET NO. E-100, SUB 124

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Investigation of Integrated Resource Planning in North Carolina – 2008 and 2009	)))	ORDER APPROVING INTEGRATED RESOURCE PLANS AND REPS COMPLIANCE PLANS

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on March 15, 16, 17, and 18, 2010

BEFORE: Commissioner William T. Culpepper, III, Presiding; Chairman Edward S. Finley, Jr.; Commissioner Lorinzo L. Joyner; Commissioner Bryan E. Beatty; and Commissioner Susan W. Rabon

APPEARANCES:

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

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For CPI USA North Carolina, LLC (CPI USA) and formerly known as EPCOR USA North Carolina, LLC:

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For Haywood, Rutherford, and Piedmont Electric Membership Corporations (EMCs):

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For the North Carolina Sustainable Energy Association (NCSEA):

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For the Southern Environmental Law Center (SELC), Sierra Club, Environmental Defense Fund, and Southern Alliance for Clean Energy (collectively the Environmental Intervenors):

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For the Using and Consuming Public:

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BY THE COMMISSION: General Statute 62-110.1(c) requires the North Carolina Utilities Commission (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 the issuance of a certificate for public convenience and necessity of construction of a generating facility. In addition, G.S. 62-110.1 requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly a report of: (1) the Commission's analysis and plan; (2) the Commission's 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 making its analysis and plan pursuant to G.S. 62-110.1.

G.S. 62-2(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 . . . .

S.L. 2007-397 (Senate Bill 3), signed into law on August 20, 2007, amended G.S. 62-2(a) to add subsection (a)(10) that provides that it is the policy of North Carolina "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS)" that will: (1) diversify the resources used to reliably meet the energy needs of North Carolina's consumers, (2) provide greater energy security through the use of indigenous energy resources available in North Carolina, (3) encourage private investment in renewable energy and energy efficiency, and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that end, Senate Bill 3 further provides that "[e]ach electric power supplier to which G.S. 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval." G.S. 62-133.9(c).

Senate Bill 3 also specifically defines demand-side management (DSM) as "activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electric use from peak to nonpeak demand periods" and defines an energy efficiency (EE) measure as "an equipment, physical or program change implemented after 1 January 2007 that results in less energy being used to perform the same function." G.S. 62-133.8(a)(2) and (4). EE measures do not include DSM. G.S. 62-133.8(a)(4).

To meet the requirements of G.S. 62-110.1 and G.S. 62-2(3a), the Commission conducts an annual investigation into the electric utilities' integrated resource planning (IRP). IRP is intended to identify those electric resource options which can be obtained at least cost to the ratepayers consistent with adequate, reliable electric service. IRP considers both demand-side options, such as conservation, EE and DSM programs, and supply-side options, including alternative supply-side energy resources, in the selection of resource options.

Commission Rule R8-60 sets out the Commission's requirements for the electric utilities' IRPs and the process for review of such IRPs. The Commission first enacted Rule R8-60 in 1988 and revised it several times thereafter. The Rule was substantially altered by the Commission's Order issued on July 11, 2007, in Docket No. E-100, Sub 111. The 2007 revisions to Rule R8-60 require biennial reports with annual updates in lieu of annual reports, continual assessments by the utilities of programs that promote DSM and EE, an increased amount of information to be provided regarding those assessments, an expansion of the planning horizon from ten to fifteen years, and an accounting in the reports for the effects of demand response (DR) and EE programs and activities. On February 29, 2008, the Commission issued an order in Docket No. E-100, Sub 113, which revised existing Commission Rules and promulgated new rules implementing Senate Bill 3. The Commission further amended Commission Rule R8-60 and promulgated Rule R8-67(b), which directs electric power suppliers subject to Commission Rule R8-60 to file their REPS compliance plans as part of their IRP filings. Commission Rules R8-60 and R8-67 applied prospectively to the 2008 biennial reports. The 2008 biennial reports were the first reports filed pursuant to revised Commission Rule R8-60.

In its March 30, 2009 Order in Docket No. E-7, Sub 858, the Commission ordered Duke to file revisions to its 2008 IRP to address the undesignated load for sales similar to that in the Orangeburg Agreement at issue in that docket and the effects on Duke's future supply and generation requirements. In its November 10, 2009 Order in Docket No. E-7, Sub 923 (Central Order), the Commission ordered Duke to present as part of its 2009 IRP testimony a revised IRP that (1) moved the load associated with the power purchase agreement with Central Electric Power Cooperative, Inc. (Central) out of the undesignated wholesale load amount, (2) contained an explanation of a discrepancy in the Central Order, (3) provided the amount of load and projected load for each wholesale customer on a year-by-year basis through the terms of the current contracts, and explained any growth rates that differ from the projections for retail load, and (4) justified any amount of undesignated load in the revised IRP as to the potential customers' supply arrangements and the reasonable expectations for serving such customers. In its January 28, 2010 Order in Docket No. E-2, Sub 960, the Commission ordered PEC to reflect its additional retirements of coal-fired generation reasonably proportionate to the amount of incremental gas-fired generating capacity authorized by the Lee certificate issued in that docket above 400 MW in its 2010 and subsequent IRPs and to address its progress in retiring its unscrubbed coal units by updates in its annual IRP filings.

Commission Rule R8-60 requires that each of the investor-owned utilities (IOUs), the North Carolina Electric Membership Corporation (NCEMC), and any individual EMC, to the extent that it is responsible for procurement of any or all of its individual power supply resources (hereinafter, collectively, "the utilities"), furnish the Commission with a biennial report in even-numbered years beginning in 2008 that contains its current IRP together with all information required by subsection (i) of Rule R8-60 covering a two-year period. In odd-numbered years, each utility shall file an annual report containing an updated 15-year forecast, supply and demand-side resources expected to satisfy those loads, the reserve margin thus produced, as well as significant amendments or revisions to the most recently filed biennial report, including amendments or revisions to the type and size of resources identified, as applicable.[1] In addition, each biennial and annual report should (1) be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports; (2) include the utility's REPS compliance plan pursuant to Rule R8-67(b); and (3) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p). Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the utilities' biennial and annual reports. Furthermore, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. The Commission must schedule one or more hearings to receive public testimony.

Procedural History

Docket No. E-100, Sub 118

2008 IRPs were filed by the IOUs, NCEMC, Piedmont EMC (Piedmont), Blue Ridge EMC (Blue Ridge), Rutherford EMC (Rutherford), and EnergyUnited EMC (EU). REPS compliance plans were also filed by the IOUs, as well as GreenCo Solutions, Inc. (GreenCo),[2] Halifax EMC (Halifax), and EU.

On August 18, 2008, GreenCo requested a waiver of the requirement for each of its member EMCs to file individual REPS compliance plans and permission for it to file a consolidated REPS compliance plan on behalf of its member EMCs, with the exception of Halifax, Rutherford, and EU. On the same day, NCEMC, Blue Ridge, Piedmont, and

[1] While the 2008 biennial reports and the 2009 annual reports may both be referred to hereinafter as "IRPs" for the respective years, it should be clear from Rule R8-60 that the requirements for a biennial report and an annual report differ.

[2] GreenCo filed a consolidated REPS compliance plan on behalf of Albemarle EMC, Blue Ridge, Brunswick EMC, Cape Hatteras EMC, Craven-Carteret EMC, Central EMC, Edgecombe-Martin County EMC, Four County EMC, French Broad EMC (French Broad), 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.

French Broad requested a waiver of the requirement to file individual REPS compliance plans and permission to have GreenCo file a consolidated REPS compliance plan on their behalf. On August 22 and 25, 2008, Duke filed a motion for an extension of time to file its biennial report and REPS compliance plan to November 3, 2008. On August 27, 2008, the Commission granted the requests of GreenCo, NCEMC, Blue Ridge, Piedmont, and French Broad for waiver of the requirement that each member EMC file an individual REPS compliance plan and for permission to file a consolidated report, and granted Duke's request for an extension of time to file its biennial report and REPS compliance plan. On August 28, 2008, Rutherford filed a notice with the Commission that its REPS compliance plan would be included in Duke's biennial report and REPS compliance plan. Also, on August 28, 2008, Rutherford filed its biennial report and Halifax filed its REPS compliance plan. On August 29, 2008, DNCP and EU filed their biennial reports and REPS compliance plans. On September 2, 2008, PEC filed its biennial report and REPS compliance plan. On September 12, 2008, NCEMC, Blue Ridge, and Piedmont filed their biennial reports, and NCEMC also filed its Energy Efficiency Potential Study Final Report. On the same day, GreenCo filed the consolidated REPS compliance plan and a motion for a protective order and confidential treatment for information attached to the consolidated report. On September 18, 2008, the Commission granted GreenCo's request for a protective order. On November 3, 2008, Duke filed its biennial report and REPS compliance plan. On January 29, 2009, Fibrowatt LLC (Fibrowatt) filed comments regarding the REPS compliance plans. On March 25, 2009, the Public Staff moved that the deadline for the filing of initial and reply comments on the biennial reports be extended. The Commission allowed the motion on March 30, 2009.

In addition to the Public Staff, the following parties intervened in Docket No. E-100, Sub 118: CIGFUR, NC WARN, Carolina Utility Customers Association, Inc. (CUCA), GreenCo, Fibrowatt, NCSEA, and the Attorney General.

On April 16, 2009, NC WARN filed its initial comments on the biennial reports and a request for an evidentiary hearing. On April 24, 2009, initial comments were filed by NCSEA, which were specifically in regard to the REPS compliance plans. Also, on April 24, 2009, the Public Staff submitted its initial comments. On May 27, 2009, reply comments were filed by the IOUs and the Public Staff. On the same day, NCSEA submitted additional comments.

On July 28, 2009, the Commission issued an Order Denying Request for Evidentiary Hearing, Scheduling Public Hearing, and Requiring Public Notice. This order set the public hearing in the Sub 118 docket for August 31, 2009. On August 12, 2009, NC WARN filed a Motion for Reconsideration and Renewal of Request of Hearing. The public hearing was held as scheduled. Six public witnesses testified in regard to REPS compliance plan issues.

Docket No. E-100, Sub 124

On or about September 1, 2009, the 2009 IRPs, which update the 2008 IRPs, were filed by the IOUs, NCEMC, Piedmont, Rutherford, EU, and Haywood. Blue Ridge had previously entered into a full requirements power purchase agreement with Duke whereby the entire Blue Ridge load is now included in Duke's IRP. Also, on or about September 1, 2009, the 2009 REPS compliance plans were submitted by the IOUs, GreenCo, Halifax, and EU. In addition to the Public Staff, the following parties initially intervened in the 2009 IRP proceeding: CIGFUR, CUCA, NC WARN, Nucor Steel-Hertford, and the Public Works Commission of the City of Fayetteville. The Attorney General filed a Notice of Intervention pursuant to G.S. 62-30.

On October 15, 2009, the Public Staff filed a motion for extension of time until January 15, 2010 for it and other intervenors to file alternative IRPs, annual reports, evaluations of, or comments on the 2009 IRPs.

On October 19, 2009, the Commission issued its Scheduling Order. In the Scheduling Order, the Commission consolidated the 2008 IRPs and the 2009 IRPs, reflecting Commission Rule R8-60 that requires the filing of biennial reports on the IRPs in even-numbered years and the filing of an update to that biennial report in odd-numbered years. The Commission found good cause to schedule an evidentiary hearing for the 2009 IRPs and REPS compliance plans filed by the IOUs. The Commission further directed that the 2009 IRPs filed by the other utilities (the non-IOUs) be addressed through the comment process contained in R8-60(j).

On November 20, 2009, EU filed an updated 2009 IRP. On December 11, 2009, DNCP filed the direct testimony and exhibits of Shannon L. Venable, M. Masood Ahmad, Michael J. Jesensky, and Aaron A. Reed; and PEC filed the direct testimony of David Kent Fonvielle, David Christian Edge, and Glen A. Snider. On January 11, 2010, Duke filed its revised 2009 IRP, the direct testimony and exhibits of Richard G. Stevie, Owen A. Smith, and James A. Riddle, and the testimony of Robert A. McMurry. On January 13, 2010, the Public Staff filed a second motion for extension of time to file comments on the non-IOUs' IRPs and REPS compliance plans, which was allowed by Commission order issued January 14, 2010. On January 29, 2010, CPI USA filed a petition to intervene, which was subsequently allowed. On February 8, 2010, the Public Staff filed comments on the non-IOUs' IRPs and REPS compliance plans. Haywood filed a letter in response to the Public Staff's comments on March 11, 2010.

On February 8, 2010, SELC filed a Petition to Intervene and Motion for Extension of Time to File Testimony. On February 11, 2010, the Environmental Defense Fund, Sierra Club, and Southern Alliance for Clean Energy also jointly filed a Petition to Intervene. On February 11, 2010, the Commission granted SELC's intervention and extended the date for the filing of intervenor testimony to February 19, 2010 and rebuttal testimony to March 9, 2010. On February 16, 2010, the Commission granted the intervention of the Environmental Defense Fund, Sierra Club, and Southern Alliance for Clean Energy.

On February 19, 2010, the Environmental Intervenors filed the testimony and exhibits of David A. Schlissel and John D. Wilson, CPI USA filed the testimony of Don C. Reading, NC WARN filed the testimony and exhibits of John O. Blackburn, and the Public Staff filed the affidavits of Jay B. Lucas, Jack L. Floyd, and Kennie D. Ellis and the testimony of John R. Hinton. On March 9, 2010, Duke filed the rebuttal testimony of Robert A. McMurry and the rebuttal testimony and exhibits of Richard G. Stevie, DNCP filed the affidavit of Shannon L. Venable, and PEC filed the rebuttal testimony of David Christian Edge, David Kent Fonvielle, and Glen A. Snider.

The public hearing regarding the 2009 IRPs and REPS compliance plans began at 7:00 p.m. on March 15, 2010 with ten public witnesses testifying before the Commission as members of the using and consuming public: Michael Thomas Cherin, June Blotnick, Alice Loyd, Elizabeth R. Hutchby, Beth Henry, Miriam Thompson, Bob Rodriquez, Zell McGee, Harry Phillips, and Mary McDowell. The public hearing was reopened at 9:30 a.m. on March 16, 2010, with Ryan William Thompson testifying as a public witness. The public witnesses generally testified in favor of energy conservation and efficiency and renewable energy, especially wind and solar, and against investment in traditional generating facilities. Many of the witnesses brought up the risks of additional coal plants to the health of North Carolina residents and to the environment. The Commission also received five letters and e-mails from customers, generally expressing strong support for energy conservation and renewable energy and urging the Commission to pursue these as integral elements in the utilities' current planning in lieu of fossil-fueled generation.

Following the conclusion of the public hearing, the parties stipulated that the testimony and affidavit of DNCP witness Venable, the testimony and exhibit of DNCP witness Ahmad, and the testimony of DNCP witnesses Jesensky and Reed be entered into the record. PEC presented the direct and rebuttal testimony of David Kent Fonvielle, Director of Fleet Optimization, David Christian Edge, Manager of Retail Market Strategy, and Glen A. Snider, Manager of Resource Planning. Duke presented the direct and rebuttal testimony of Richard G. Stevie, Managing Director of Customer Market Analytics, and Robert A. McMurry, Director of Integrated Resource Planning and the direct testimony of Owen A. Smith, Managing Director of Renewable Strategy and Compliance, and James A. Riddle, Manager of Load Forecasting in the Customer Market Analytics Department. NC WARN presented the direct testimony of John O. Blackburn, Ph.D., Professor Emeritus of Economics, Duke University. The Public Staff presented the testimony of Jack L. Floyd, Kennie D. Ellis, and Jay B. Lucas, engineers with the Electric Division of the Public Staff and John R. Hinton, Financial Analyst with the Economic Research Division of the Public Staff. The Environmental Intervenors presented the testimony of John D. Wilson, Director of Research for the Southern Alliance for Clean Energy, and David A. Schlissel, President of Schlissel Technical Consulting, Inc. CPI USA presented the testimony of Don C. Reading, Vice President and Consulting Economist with Ben Johnson and Associates, Inc.

On June 10, 2010, a brief was filed by NC WARN. On June 11, 2010, briefs were filed by the Environmental Intervenors and CPI USA. Also on June 11, 2010, proposed orders were filed by DNCP, PEC, Duke, and the Public Staff. On June 17, 2010, NC WARN filed a correction to its brief.

Although made shortly after the parties' post-hearing filings, approval of the 2008 IRP filings comes later than otherwise would have been the case due primarily to a change in Commission Rule R8-60 requiring an update to the even-year IRP filings. The next IRP filings will be due on September 1, 2010. With one round of IRP proceedings under new procedural rules behind us, the Commission contemplates that the 2010 filings and the Commission's determination will be timely and in accordance with the schedule and procedure prescribed in Commission Rule R8-60. Accordingly, with respect to future IRP proceedings, all parties are advised that requests for extensions of time will be appropriately scrutinized with an eye toward keeping the proceedings on schedule in order to serve the purposes of the governing statute.

Based upon the foregoing, the information contained in the 2008 biennial reports, the 2009 annual updates to the 2008 biennial reports, the REPS compliance plans, the testimony and exhibits introduced at the hearings, and the Commission's 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 and should be approved.

2. The IOUs' 2008 biennial reports, and the 2009 annual updates to the 2008 biennial reports, are reasonable and should be approved.

3. The IOUs' 2009 REPS compliance plans are reasonable and should be approved.

4. The IOUs should continue to investigate the opportunities to utilize air conditioning cycling load management programs as a way to reduce load and to reduce fuel costs.

5. The 2008 biennial reports, and the 2009 annual updates to the 2008 biennial reports, and 2009 REPS compliance plans submitted by NCEMC, Piedmont, Blue Ridge, Rutherford, EU, Haywood, GreenCo, and Halifax are reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence supporting this finding of fact is contained in the testimony of DNCP witnesses Ahmad and Venable, PEC witnesses Snider and Edge, Duke witnesses McMurry, Riddle, and Stevie, NC WARN witness Blackburn, Environmental Intervenor witness Wilson, and Public Staff witnesses Hinton, Ellis, and Floyd, and the 2009 IRPs of DNCP, PEC, and Duke.

DNCP witness Ahmad adopted the portions of DNCP's 2009 IRP dealing with its annual load forecast, as well as its proposed supply-side resources. Chapter 2 of DNCP's 2009 IRP contains its description of methodology for forecasting its peak demand and energy sales needs. DNCP's 15-year forecast from 2010 through 2024 predicted that its summer peaks will grow at an annual average rate of 2.0% after the effects of EE and DSM are included. DNCP's energy sales are predicted to grow at an average annual rate of 2.2% after DSM and EE are included. DNCP is obligated to maintain a reserve margin for its portion of the PJM coincidental peak load, resulting in an effective reserve margin requirement of 12%. Public Staff witness Hinton testified that DNCP's forecasts of peak demand and total energy sales were valid and reasonable for planning purposes.

PEC's 15-year forecast from 2010 through 2024 contained in its 2009 IRP indicates that its system peak loads will grow at an annual average rate of 1.6% after the effects of EE and DSM are included. PEC's energy sales are predicted to grow at an average annual rate of 1.4% after the effects of EE and DSM are included. According to PEC witness Snider, this forecasted growth is comparable to PEC's forecasts in recent years. He also stated that there has been a reduction in the peak load forecast and growth in the near term due to the continuation of the current economic downturn. Mr. Snider further indicated that PEC used the same methods, tools, and models in its 2009 IRP that it employed to develop load and energy forecasts presented to this Commission in prior IRP proceedings in recent years. PEC's 2009 IRP reflects reserve margins of approximately 13% to 26%. Public Staff witness Hinton agreed that PEC's growth rates in the 2009 IRP were similar to those in the 2008 IRP. He further testified that PEC's forecasts of peak demand and total energy sales were reasonable and valid for planning purposes. PEC witness Edge presented testimony regarding PEC's DSM and EE forecasts, as well as its programs and plans. He testified that between 2009 and 2023, PEC forecasts that the projected savings impact for all cost-effective EE will be 3.8% of total retail energy sales.

Duke's 15-year forecast from 2010 through 2024, as reflected in its revised 2009 IRP, predicted that its summer peaks after EE will grow at an annual average rate of 1.8%. Duke's energy sales are predicted to grow at an average annual rate of 1.6% after accounting for the effects of EE. Duke witness McMurry testified that Duke's revised 2009 IRP incorporates a target planning reserve margin of 17%, which Duke's historical experience has shown to be sufficient. Witness Riddle noted that the load forecast portrays the level of expected peak demand prior to any reductions for DSM programs, which are captured and incorporated in the development of the IRP as an offset to the load forecast. Duke witness Stevie noted that after the inclusion of the EE programs, retail sales projected for 2014 are actually below the level for 2009.

Pursuant to the Central Order, Duke's revised 2009 IRP moved the Central wholesale load from undesignated load, provided the amount of load and projected load for each wholesale customer and an explanation for a discrepancy between the growth rates between the wholesale loads and Duke's retail loads, and provided a justification for any amount of undesignated load and the reasonable expectations for serving such customers. Duke witness Riddle testified that he projects slightly less than 1% growth attributable to retail customers with EE and 1.3% without EE, and slightly more than 3.5% to 4% growth attributable to wholesale customers over the 15-year period. Mr. Riddle in his direct testimony addressed possible reasons for the differences in the demand of Duke's wholesale customers as opposed to its retail customers. He pointed out that, in general, wholesale customers' usage is concentrated more with residential and commercial end users with comparatively less industrial usage, as compared to Duke's retail usage, which is more widely distributed among the industrial, commercial, and residential classes. Mr. Riddle stated that because of these characteristic differences, different growth rates are to be expected. He also pointed out that the Central contract provides for a seven year step-in to the customer's full load requirement, with Duke providing 15% of Central's total member cooperative load in 2013, followed by 15% annual increases in load over the subsequent six years until all of the contract load is met.

Duke witness McMurry testified regarding the inclusion of the Central load as a firm requirement and the undesignated load associated with wholesale customers Duke believes it has a reasonable expectation to serve. He was questioned as to the analysis Duke uses to determine whether it has a "reasonable expectation" of serving a customer. Mr. McMurry testified that Duke used an estimate based on whether it believed it had more than a 50% chance of serving a particular customer within the foreseeable future. While Mr. McMurry could not provide an exact answer as to how Duke defined the "foreseeable future," he stated that if it did not appear that a contract would begin in the next two years, Duke should not include that customer in its current IRP. Mr. McMurry said that in such a case, Duke should include the contract in the following IRP if Duke had a reasonable expectation of serving that customer. Mr. McMurry agreed that each wholesale contract differed as to its individual facts and circumstances and that this analysis of whether Duke had a "reasonable expectation" of serving a particular wholesale customer involved a certain amount of subjectivity. He testified that both the inclusion of the Central load and the specified undesignated wholesale load associated with customers whom Duke has a reasonable expectation to serve increased the need for combustion turbine generation in the 2017 and 2026 timeframe.

Public Staff witness Ellis noted that Duke's 2009 IRP filed September 1, 2009, maintained a reserve margin averaging 18.8% throughout the planning horizon, while its revised 2009 IRP incorporated undesignated wholesale load and some changes to the capacity addition schedule, resulting in a reserve margin averaging 19.1% through the planning horizon. Public Staff witness Hinton testified that before inclusion of Duke's wholesale loads, the growth rate of Duke's summer peak demand from 2010 through 2024 is 1.2%, and the growth rate for total energy sales is 1.1%, which is similar to the growth rates in Duke's 2008 IRP. He further testified that the addition of the Central wholesale load and the undesignated load increases the growth rate of the summer peak demand to 1.8% and the growth rate of its total energy sales to 1.6%. Mr. Hinton testified that he found Duke's forecasts of peak demand and total energy sales to be valid and reasonable for planning purposes.

Duke witness McMurry testified that Duke's load forecast was updated to account for the projected load impacts for EE and demand-side resources associated with the settlement in Docket No. E-7, Sub 831 (save-a-watt). Duke witness Stevie testified that the conservation impacts were assumed at 85% of the target impacts from the terms of the save-a-watt settlement (Base Case). Dr. Stevie further testified that the projected load impacts from the conservation programs were based upon three bundles of the portfolio of programs with a new bundle entering every four years. The projected load impacts from Duke's DSM programs are based upon continuing and new DR programs. Dr. Stevie explained that the projection of EE impacts in the 2009 IRP differed in several respects from the 2008 projection: the start of the programs was delayed to the middle of 2009, the EE impacts were scaled up in the third and fourth years consistent with the save-a-watt settlement, and new information on the load shape associated with hourly load savings from the installation of compact fluorescent light bulbs was incorporated into the projection of the coincident peak load impacts. Dr. Stevie explained that the load forecasts prepared by Duke witness Riddle capture the effects of EE trends and activities, including EE resulting from rising fuel prices that occur outside of the Company's own EE programs. Dr. Stevie testified that under Duke's Base Case, which was scaled down to 85% of the projected impacts from the save-a-watt settlement, it projected that by 2020 it would have cumulative energy savings of 4.5% to 5%, or 7% if the effect of increasing energy prices is included. Under Duke's High Case scenario,[3] Dr. Stevie testified that Duke projects a 13.5% decrease in retail sales as a result of EE and DSM by 2029. However, Dr. Stevie testified that although Duke is committed to pursuing all cost-effective EE, he believes achieving the savings target in its High Case would be quite a "stretch." Duke witness McMurry indicated on cross examination that it was too early to tell whether Duke would be able to meet the EE goal to which it had agreed in the save-a-watt docket. He pointed to the number of industrial and commercial customers opting out, as well as a weak adoption rate as potential causes for Duke to miss the goal. He stated that Duke was making its best efforts, but that success in reaching the goal was also contingent on the availability of cost-effective EE.

Public Staff witness Floyd noted that the 2009 IRPs of Duke, PEC, and DNCP included slightly lower impacts from DSM and EE resources than their 2008 IRPs. He opined that this difference is the result of delays in implementation of DSM and

[3] The High Case scenario uses 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 annually until the load impacts reach the economic potential identified by the 2007 market potential study.

EE programs due to current economic conditions, as well as delays in the timing of development, approval, and rollout of the various programs within each portfolio.

NC WARN witness Blackburn testified that the forecasts of PEC and Duke overstated the demand for electricity. Dr. Blackburn produced a plan in which he deducted new wholesale contracts that he deemed unnecessary and recommended an annual EE goal of 1.5%. Dr. Blackburn did not intend that the utilities adopt an annual EE goal of 1.5% for their utility-administered programs, rather he believes that this amount of annual EE savings is achievable in North Carolina during the planning horizon through a combination of utility-sponsored programs, revised building codes, and governmental, individual, and corporate initiatives. In fact, Dr. Blackburn stated that if there were changes in building codes and local, state and federal standards, issuance of executive orders, and governmental initiatives increasing EE, there might be little left for the utilities to do.

Duke witness Stevie questioned the studies on which Dr. Blackburn relied to arrive at his recommendation of a 1.5% annual savings goal for EE. He cited a January 2009 study by the Electric Power Research Institute that implied a reasonable annual savings recommendation of approximately 0.6%. Dr. Stevie pointed out that 8% of Duke's total retail load from the commercial and industrial sector had chosen to opt-out from participation in Duke's EE programs. Duke witness McMurry pointed out that Dr. Blackburn's proposed plan had removed the wholesale contract to supply the load of Central, a wholesale customer that had been historically served by Duke. He also pointed out that Dr. Blackburn's analysis did not provide for any reserve margin and did not contain any detailed cost analysis. PEC witness Edge questioned the American Council for an Energy-Efficient Economy (ACEEE) study cited by Dr. Blackburn, in that it did not take into consideration the opt-out provision available to commercial and industrial customers in North Carolina, which represents 40% of PEC's retail sales. He also pointed out that the ACEEE study reported projected savings in terms of gross savings, while PEC's savings projections are based on net savings. Mr. Edge testified that he believed that it would be inconceivable for PEC to have a goal of 1% annual energy savings over the planning horizon based on PEC's analysis of cost-effective potential EE based under the screening of the total resources cost test.

Environmental Intervenor witness Wilson testified that for 2010, the utilities forecast reducing system sales by 0.3% through EE programs, which he termed a "good start." Mr. Wilson calculates cumulative energy savings from the utilities of 3.1% over the next 15 years. He recommended an annual goal of 1% with projected savings of up to 15% by 2024 for the utilities. PEC witness Edge testified on rebuttal that he disagreed with Mr. Wilson's contention that PEC should have a goal of achieving savings from EE of 15% by 2024. Mr. Edge criticized the studies on which Mr. Wilson relied in that none were specific to PEC's service area, some only projected economic potential, some did not consider the effects of "free riders,"[4] some were regional while others were national

[4] "Free riders" are generally described in the testimony as customers who undertake EE measures on their own initiative, without the influence of utility participant incentives. PEC witness Edge indicated that the energy savings resulting from free riders are not reflected in PEC's projections of energy savings.

in scope, some were meta-analyses of other studies, some relied on implementation of policies beyond those utility-implemented programs, and none took into account the opt-out provision of Senate Bill 3. Mr. Edge testified that both the 15% target by 2024 advocated by Mr. Wilson and the 1.5% annual target advocated by Dr. Blackburn were overly optimistic as they failed to account for the opt-out provision of Senate Bill 3 or new governmental efforts to stimulate EE that reduce the savings potentials for utility-administered programs. Mr. Edge testified that PEC should not rely on the aspirational goals proposed by Dr. Blackburn or Mr. Wilson, but rather on its own comprehensive analysis of available EE and DSM potential in its service territory and its experience implementing and evaluating its programs. Mr. Edge testified that comparison with the EE achievements in states such as Vermont, California, and New Jersey was unfair when numbers from those states' programs reflected achievements prior to the enactment of the Energy Independence and Security Act (EISA), which banned continued used of incandescent light bulbs. The numbers from those programs also do not account for free riders. Mr. Edge testified that in 2007, PEC committed to defer 1000 MW of generation through DSM and EE and that PEC projects a savings of 3.8% through EE and DSM by 2023. PEC witness Snider pointed out that supply-side resources differed from demand-side resources in that a planner could anticipate the quantity of the supply-side resources with greater certainty than with demand-side resources. He testified that this lack of certainty regarding demand-side resources translates into concerns regarding reliability and risk when forecasting DSM and EE.

DNCP witness Venable disagreed with Mr. Wilson's suggestion that the IOUs should meet an annual energy savings goal of 1%, as that target exceeds the requirements of Senate Bill 3. Nonetheless, Ms. Venable testified that DNCP is committed to pursuing EE that is cost-effective and appropriate for its customers.

In making his recommendation of an annual goal of 1% with projected savings of up to 15% by 2024 for the utilities, Environmental Intervenor witness Wilson pointed to states with lower or comparable electricity rates that had achieved much higher rates of EE savings. Duke witness Stevie disagreed with Mr. Wilson's contention that there was little correlation between electricity prices and EE savings and sponsored a rebuttal exhibit showing what he termed "a direct and significant relationship" between the price of electricity and the percent annual incremental EE achievement. Dr. Stevie further testified that it is easier to find cost-effective EE when rates are higher than when they are lower. PEC witness Edge also disagreed with Mr. Wilson's analysis of the correlation between electricity prices and EE. Mr. Edge pointed out that the 2009 ACEEE study cited by Mr. Wilson acknowledges that the highest EE cost savings have been achieved in states with high electricity rates. Mr. Edge also pointed out that there was a correlation between the level of electricity prices and the number of cost-effective EE programs and measures in a state.

Based on the foregoing, the Commission concludes that the energy and peak load forecasts of the IOUs are reasonable and appropriate. The IOUs' forecasting methodology is well accepted in the industry and has proven over time to be reasonably accurate. While the EE savings goals suggested by Dr. Blackburn and

Mr. Wilson may seem attractive, they fail to take into account the opt-out provision of Senate Bill 3, which allows a significant portion of the potential market for savings from EE to decline participation in the utilities' programs. Moreover, the utilities' post-Senate Bill 3 programs are in their early stages and have not been rolled out as quickly as anticipated due to various reasons enumerated above by both utility and Public Staff witnesses. As such, the projections of EE and DSM savings forecasted by the IOUs are found to be reasonable within this proceeding for planning purposes. This should not be regarded as any indication of low expectations for EE and DSM savings on the part of the Commission. These projections are subject to review and re-evaluation in future IRP proceedings and should not be regarded as static. These projections very well could change as the utilities' EE and DSM programs mature and are subject to measurement and verification, and as opportunities for refining existing programs or creating new programs appear on the horizon.

In regard to the appropriate treatment of wholesale load, the Commission finds that in future IRPs, all utilities should be required 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. Further, the approval of any IRP that includes undesignated load should not be cited as advance approval of any wholesale contract or method of cost allocation associated with any wholesale contract in a future proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

The evidence supporting this finding of fact is contained in the testimony of DNCP witnesses Jesensky and Venable, PEC witness Snider, Duke witnesses McMurry, Riddle, and Stevie, NC WARN witness Blackburn, Environmental Intervenor witnesses Wilson and Schlissel, and Public Staff witness Ellis, and the 2008 and 2009 IRPs of DNCP, PEC, and Duke.

DNCP witness Venable presented testimony regarding the utility's 2009 IRP, including an overview of the IRP process and a discussion of the Company's plans for future REPS filings. She noted in her direct testimony that DNCP's 2009 IRP included provisions to achieve policy goals from individual state legislatures. DNCP witness Jesensky discussed the utility's current, proposed, and future DSM programs. DNCP's IRP indicates that it has not filed for approval of DSM programs in North Carolina, but plans to implement a portfolio of DSM programs in Virginia after the Virginia State Corporation Commission approves them, and will evaluate and consider these programs for approval and implementation in North Carolina.[5] Environmental

[5] The Commission notes that in Docket No. E-22, Sub 418, on March 11, 2010, DNCP was ordered to file for approval appropriate demand response (DR) programs for its North Carolina customers by September 1, 2010.

Intervenor witness Wilson recommended that DNCP file its proposed EE programs in North Carolina as expeditiously as possible and recommended that all the utilities participate in a regional EE database and collaboration process. According to DNCP witness Venable, while DNCP does not support the creation of a regional EE database and collaboration process, it does support an inclusive stakeholder process.

PEC witness Snider testified that he oversaw the development of PEC's 2009 IRP. According to Mr. Snider, with regard to new supply resources, the only resources PEC is committed to install are the combined-cycle generation facilities at PEC's Richmond County and Wayne County sites. He stated that all other generation additions shown in PEC's plan are generic resources indicating the need for additional generation. According to Mr. Snider, PEC has made no commitments to any specific type, amount, location, or ownership of the needed capacity.

Duke witness McMurry testified that he oversees long-term resource planning for Duke. According to Mr. McMurry, based on the results of the 2009 IRP, the assumed retirement dates of Duke's older fleet of combustion turbines at Buck Steam Station, Dan River Steam Station, Riverbend Steam Station and Buzzard Roost Combustion Turbine Station were accelerated from the 2014-2015 timeframe to June 2012, and the remaining coal units without scrubbers at Buck Steam Station Units 5 and 6 and Lee Steam Station Units 1 through 3 were assumed to be retired in 2020 based on expected increased regulatory scrutiny. He stated that these planned retirements total an additional 625 MW of retired generation in the 2009 IRP as opposed to the 2008 IRP. Mr. McMurry testified that due to the impact of the recession on load growth, the combustion turbine portion of the new Buck combined cycle plant will not be operable during the summer of 2011, and the need for the new Dan River combined cycle plant has been delayed until the summer of 2013. Based on Duke's analysis, it determined that the addition of the Central load increases the need for combustion turbine generation in the 2017 and 2026 timeframe and supports the need for nuclear generation in the 2018 to 2021 timeframe. Mr. McMurry testified that the nuclear project cost escalation rate was also reduced from the 2008 to 2009 IRP. He stated that even with the inclusion of the updated information for the revised 2009 IRP, the basic conclusions of the 2008 IRP are unchanged.

NC WARN witness Blackburn testified that, in his opinion, substantially all of Duke's and PEC's coal plants could be phased out within the planning period without the addition of new nuclear generation if the following goals were achieved: (1) an annual EE goal of 1.5% over the planning period, (2) a renewable energy goal of 20%, and (3) a customer cogeneration or combined heat and power (CHP) goal that amounts to 16-17% of total power generation in North and South Carolina. Dr. Blackburn noted that in his plan, existing hydroelectric power would be allowed to count toward the renewable energy target. Dr. Blackburn conceded on cross-examination that his plan did not include any reserves and that additional costs for transmission, grid stability, and voltage control would be incurred if the renewable resources envisioned under his plan were added to the grid. Dr. Blackburn also agreed that implementation of his plan could require changes in laws and policies beyond the purview of the Commission.

Dr. Blackburn testified about a study he performed regarding how wind and solar might offset each other when operated in tandem despite their intermittent nature. His study showed that while the stream of electricity from the two sources still fluctuated when operated in tandem, it was much more stable. He concluded that while intermittency is a problem, it is manageable. On cross-examination, Dr. Blackburn admitted that he had matched loads on an hourly basis, rather than on a second or minute basis. He further conceded that of the 123 days of his study, there were three days when there was an inadequate supply of electricity and 17 hours when there was a need for back-up generation. The study also assumed from the onset that consumption was reduced by 20% due to EE.

Duke witness McMurry testified on rebuttal that history indicated that it was not economically feasible for customers to build CHP facilities on a large scale, and that he deemed Dr. Blackburn's CHP goal unrealistic. Mr. McMurry found Dr. Blackburn's plan to be flawed, and declared it to be a plan that would result in both higher costs and less reliability, contrary to the goals of IRP. Mr. McMurry referred to Dr. Blackburn's proposal as a "vision plan" as opposed to a resource plan.

Environmental Intervenor witness Schlissel testified that Duke's emissions from carbon will increase in each of its resource portfolios between 2010 and 2029 despite its plan to retire 1,600 to 1,700 MW of cycling coal units by 2020 as a result of the addition of Cliffside Unit 6. He also advocated that Duke and PEC consider the regulation of coal combustion products (CCPs) in their IRPs. Mr. Schlissel recommended that Duke use a wider range of carbon prices and testified that the methodology PEC used to make its assumptions regarding carbon prices was inadequate. He stated that if Duke were to build more natural gas fired generation, it would diversify Duke's portfolio and lower its emissions, especially since natural gas has been forecasted to have a greater supply and a lower price than had been previously thought. Mr. Schlissel pointed out that PEC mentions potential regulation of coal combustion waste as a significant challenge, but that Duke's IRP does not address the issue. He criticized Duke and PEC for not sufficiently reflecting the current and upcoming regulatory challenges surrounding air emissions. Mr. Schlissel recommended that the Commission require the utilities to include a detailed discussion and analysis of pollution control standards and to show how these are factored into their IRPs.

Duke witnesses McMurry and Riddle testified that one major difference between Duke's 2008 and 2009 IRPs was that Duke began incorporating the expected impact of greenhouse gas regulation into its load forecast in its 2009 IRP. However, Duke did consider the impact of carbon legislation in its 2008 IRP in its Higher Carbon Case analysis. Duke witness McMurry testified on rebuttal that as a result of its planned retirements and additions, including Cliffside 6, Duke's CO_2/MWh emissions will decline by 30% by 2029. He also pointed out that adding natural gas-fired plants would not significantly alter the dispatch order for generation and therefore not significantly impact Duke's CO_2 emissions. Mr. McMurry further testified that even with lower natural gas prices, Duke's analysis indicates that it would not be cost-effective to retire other coal-fired plants and replace them with natural-gas-fired plants. He testified that while not explicit in its IRP, Duke's analysis did consider the regulation of coal ash and its by-products. While Mr. McMurry did not agree with Mr. Schlissel that Duke should have used a wider range of potential carbon prices in its 2009 IRP based on the circumstances at that time, he stated that Duke may consider using a wider range in its 2010 IRP.

PEC witness Snider testified that PEC's plan reflects acknowledgment of the widely accepted assumption that there will be environmental legislation in the future requiring review of continued operation of certain coal-fired generation. This potential environmental legislation includes a carbon tax, the Clean Air Interstate Rule, maximum achievable control technology requirements in the wake of the vacatur of the Clean Air Mercury Rule, revision of the National Ambient Air Quality Standards for ground-level ozone, regulation of CCPs, and other laws or rules dealing with global climate change. According to Mr. Snider, as the 2009 IRP was an update to the 2008 IRP, PEC factored these legislative changes into its cost assumptions, but did not run different sensitivities when performing its IRP modeling in 2009.

Environmental Intervenor witness Wilson testified that the IOUs still treat EE as a second-class resource by failing to consider demand-side resources on an equivalent basis with supply-side resources. He noted that while all of the IOUs described their various EE or DSM programs in their 2009 IRPs, they did not describe the capacity, energy, number of customers and other required information for each program over the 15-year period. Mr. Wilson pointed out that this descriptive data was important for the Commission to analyze whether demand-side resources were being considered on an equal footing with supply-side resources. He further testified that both Duke's Base Case and its High Case appear to have been developed in a manner that does not reflect the program design principles and intent of the approved programs, in that they understate the probable impact of Duke's EE programs. Mr. Wilson recommended that Duke revise its resource plan to reflect a consistent trend in EE program growth consistent with available EE potential and opportunities for reasonable program growth. He also found certain information in PEC's IRP regarding the capacity and energy impacts of its demand-side resource forecast to be inconsistent or confusing. Mr. Wilson contended that neither Duke nor PEC performed a comprehensive analysis of demand-side resources in their 2009 IRPs. He recommended that the utilities either perform an EE potential study that captures all possible EE measures or set an annual energy savings goal that is benchmarked against leading efforts across the country. Mr. Wilson suggested that the Commission require the utilities in their resource planning to provide a more detailed explanation of how they selected their preferred portfolios, consider risks that cause short-term rate spikes, and create a regional EE database and collaboration process.

Duke witness Stevie disagreed with Mr. Wilson's contention that Duke relegated EE to a second-class status. Dr. Stevie explained that Duke evaluates demand and supply-side resources in a portfolio modeling exercise by having them compete with each other in an optimization model. While Dr. Stevie agreed with Mr. Wilson that Duke should have described the capacity, energy, number of customers and other required information for each EE or DSM program over the 15-year period, he disagreed with Mr. Wilson's charge that Duke had not included a comprehensive analysis of EE measures in its IRP. Dr. Stevie testified on rebuttal that Duke had already engaged in a bottom-up approach to study the economic potential of EE as advocated by Mr. Wilson. Dr. Stevie agreed with Mr. Wilson's statement that neither an EE potential study nor industry experience can provide as precise measure of cost-effective EE as a supply-side generation plan that can anticipate generation capacity. Dr. Stevie pointed out that there is greater uncertainty associated with the implementation of EE programs that can only be resolved as experience is gained with the newly implemented programs. He testified that as Duke had an ongoing collaborative process, there was not a need for a regional collaborative as suggested by Mr. Wilson. However, Dr. Stevie agreed with Mr. Wilson that a regional database should be created and kept up to date. Dr. Stevie testified that Duke should update its market potential study at least every five years, thus the 2007 study should be updated by at least 2012.

PEC witness Snider noted in his rebuttal testimony that PEC had assumed in IRPs prior to 2009 that all longer term power purchase agreements (PPAs) were perpetually renewed. PEC's 2008 IRP lists six wholesale PPAs with four entities that were assumed to be renewed following the expiration of the contracts. Beginning with the 2009 IRP, PEC assumed that such PPAs would expire at the end of their current terms. Mr. Snider listed several factors in support of this change. PEC has the right to purchase capacity only for the duration of the existing contract. At the expiration of the contract, the owner might elect to sell the capacity and energy to another purchaser, the facility might not be capable of providing reliable power to PEC, the owner might not have the financial ability to support a future agreement, or PEC might determine that the resource is not optimal for a variety of reasons. In the case of a facility producing renewable energy, the viability of the facility may be affected by external factors such as tax credits, steam hosts, renewable status, and environmental compliance.

Public Staff witness Ellis testified that the discussions of generating facilities, reserve margin adequacy, non-utility generation, wholesale power contracts, transmission facilities, transmission planning, evaluation of resource options, and levelized busbar costs in the 2009 IRPs of DNCP, PEC, and Duke, which were updates to the 2008 biennial reports, appeared to meet the requirements of R8-60.

Rule R8-60(h) requires that annual reports, such as the 2009 IRPs, contain an updated 15-year forecast of native load requirements and other system capacity or firm energy obligations; supply-side and demand-side resources expected to satisfy those loads; the reserve margin thus produced; significant amendments or revisions to the most recently filed biennial report, including amendments or revisions to the type and size of resources identified, as applicable; a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate; and the utility's REPS compliance plan pursuant to Rule R8-67(b). Unless there have been significant amendments or revisions to the biennial plan, the utility in an annual report is not required to perform the comprehensive analysis of all resource options pursuant to Rule R8-60(c)(2), nor to provide the items required by Rule R8-60(d), (e), (f), and (g). Utilities may certainly provide this information on a voluntary basis. This was the first year that the utilities filed annual IRP reports pursuant to the revised Rule R8-60, and it appears that there was confusion regarding the difference in requirements for a biennial report and an annual report. In order to reduce such confusion, the Commission will require the inclusion in future annual reports of an introduction in which the utilities list any circumstances which necessitate significant amendments or revisions to the most recently filed biennial reports and specify the portions of such biennial reports that have been amended or revised.[6]

Because the 2009 IRPs were annual reports as opposed to biennial reports, the utilities were not required to perform the same level of analysis as required for a biennial report unless there had been significant changes or revisions. It appears that to some extent, both PEC and Duke took into account the changes in environmental regulation occurring in the interval between their 2008 and 2009 IRPs. The regulatory climate surrounding climate change, CCPs, and other environmental issues certainly changed from the filing of the 2009 IRPs in September 2009 to the time of the hearing in March 2010, and the Commission expects that it will have changed by the time the 2010 IRPs are filed in September 2010. The biennial reports are to contain all required information, full and robust analyses and sensitivities, which should encompass a range of scenarios including potential regulatory changes.

While it should be clear at this point, the Commission reiterates that inclusion of a DSM or EE program, a proposed new generating station, a proposed new transmission line, or a purchased power contract in a utility's IRP filing does not constitute approval of any of those aspects of the plan even if the IRP as a whole is approved.

Based on the foregoing, the Commission's review of the 2009 annual updates and the 2008 biennial plans, and the entire record of this proceeding, the Commission concludes that the 2008 and 2009 IRPs submitted by the IOUs are reasonable for purposes of this proceeding and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence supporting this finding of fact is contained in the testimony of Duke witness Smith, DNCP witnesses Reed and Venable, PEC witness Fonvielle, CPI USA witness Reading, and Public Staff witnesses Lucas and Ellis, and the 2009 REPS compliance plans of DNCP, PEC, and Duke.

Duke witness Smith testified that under G.S. 62-133.8(b)(1), each utility in the State must comply with the REPS requirement in accordance with a statutorily set schedule based upon 3% of the utility's North Carolina retail sales beginning in the year 2012, 6% in 2015, 10% in 2018 and 12.5% in 2021 and thereafter. Additionally, G.S. 62-133.8(d) requires that each utility satisfy its REPS requirement with solar energy based upon 0.02% of the utility's North Carolina retail sales beginning in the

[6] This does not apply to the information required to be filed annually pursuant to Rule R8-60(c)(1).

year 2010, 0.07% in 2012, 0.14% in 2015, and 0.20% in 2018 and thereafter. In its Order Clarifying Electric Power Suppliers' Annual REPS Requirements, issued on November 26, 2008, in Docket No. E-100, Sub 113, the Commission clarified that the calculation of these requirements for each year would be based upon the utility's North Carolina retail sales for the prior year. Additionally, the Commission has clarified that the swine and poultry waste set-aside requirements of G.S. 62-133.8(e) and (f) are aggregate obligations of the utilities. Mr. Smith testified that upon the passage of Senate Bill 3, Duke modified its consideration of renewable energy resources. Instead of screening such resources based on their economics, initial consideration is given to the level of renewable resources necessary for compliance with G.S. 62-133.8 and the Commission's rules. Public Staff witness Lucas testified that he believed that Duke should be able to meet its REPS requirements for the period covered by its plan, 2009-2011.

DNCP witness Reed presented testimony regarding the Company's 2009 REPS compliance plan filed with its 2009 IRP. Ms. Venable testified that the Company has been having difficulty obtaining poultry and swine renewable energy resources, but has been cooperating with the other IOUs in Docket No. E-100, Sub 113, to develop a solution. Public Staff witness Lucas testified that he believed that DNCP should be able to meet its REPS requirements for the period covered by its plan, 2009-2011.

PEC witness Fonvielle testified that based on experience to date and current assumptions, PEC's REPS plan is projected to achieve compliance with the REPS requirements. However, he noted that there are significant uncertainties that could adversely impact PEC's ability to meet the long-term REPS requirements. These uncertainties include undesignated future resources that may not materialize, as well as changes in the cost or availability of resources, especially set-aside resources. Mr. Fonvielle noted that since the filing of its 2009 REPS compliance plan, PEC had resolved issues involving its poultry waste set-aside and that it was actively pursuing meeting that requirement for 2012. Mr. Fonvielle testified that PEC's 2009 REPS compliance plan indicates that based on its projected requirements, EE, and contracted resources, PEC has enough resources to achieve compliance through 2013 and needs a minimum of an additional 170 gigawatt-hours to be in compliance in 2014. However, Mr. Fonvielle testified that based on current prices, the chances of PEC being able to reach Senate Bill 3's 12.5% goal in 2021 without reaching the price cap imposed by G.S. 62-133.8(h)(3) and (4) were not "so great" in the long term, though PEC's chances of meeting the goals in the early and mid-term were more favorable. He also stated that PEC was in good shape to meet its REPS goals through 2018 based on current expectations. Mr. Fonvielle expressed his hope that the development of a more competitive market would drive prices down and make the goals more achievable in the long term. Public Staff witness Lucas testified that he believed that PEC should be able to meet its REPS requirements for the 2009-2011 period covered by its plan.

Public Staff witness Ellis testified that unless the price of RECs drops considerably, meeting the REPS requirements beyond the short term could become challenging, as the IOUs may reach the caps in the near future. Mr. Ellis pointed out the fact that under Senate Bill 3, the cost caps do not rise as quickly as the REPS requirements. According to Mr. Ellis, this could create a situation where the utilities reach the cost caps before they meet the REPS goals.

CPI USA witness Reading testified that with the significant lead time required to build new renewable resources, he doubted whether PEC could meet the mandates of Senate Bill 3 in regard to in-state RECs. He pointed to the output of the facilities of CPI USA as a potential source for such in-state RECs, and noted the pending arbitration between his client and PEC over a PPA. Mr. Reading stated that while PEC's 2008 IRP listed cogeneration resources of 179 MW, these resources have been reduced to zero in PEC's 2009 IRP, indicating a less robust and balanced resource plan. Mr. Reading further testified that his calculations indicated that the most readily available resource by which PEC could meet its REPS requirement is biomass. He testified that PEC showed no deficit in renewable resources until 2014, and that PEC would have three years to attain those requirements. CPI USA's specific interest in this issue is the subject of a separate arbitration proceeding before this Commission in Docket No. E-2, Sub 966, and will be addressed by the Commission in that docket.

No party contended that the IOUs' REPS compliance plans for 2009-2011 were insufficient, but there was concern whether the IOUs could meet the REPS mandates through 2021 without reaching the cost caps. The Commission shares this concern and will closely monitor the utilities' compliance plans and their progress toward meeting each of the REPS requirements in the coming years.

The 2009 REPS compliance plans submitted in Docket No. E-100, Sub 124, completely supersede the 2008 REPS compliance plans submitted in Docket No. E-100, Sub 118. Therefore, the Commission has not made any determination as to the acceptability of the 2008 plans.

Based on the foregoing, the Commission's review of the 2009 REPS compliance plans, and the entire record of this proceeding, the Commission concludes that the 2009 REPS compliance plans submitted by the IOUs are reasonable for purposes of this proceeding and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence supporting this finding of fact is contained in the testimony of, DNCP witness Venable, PEC witness Snider, and Public Staff witnesses Floyd and Hinton, and the 2009 IRPs of DNCP, PEC, and Duke.

Public Staff witness Floyd testified that the IOUs should utilize their DSM resources to obtain the maximum system value possible. He pointed out that while increased utilization of DSM might not lead to capacity savings, it might result in energy savings, with corresponding fuel savings. Mr. Floyd noted that both Duke and PEC received approval in 2009 for new residential air conditioning cycling programs that provide the capability to control central air conditioning systems in a manner that causes less customer inconvenience than earlier versions of such programs. He encouraged the IOUs to maximize the value of these air conditioning cycling programs. Similarly, Public Staff witness Hinton testified that while increased activation of these cycling programs should not have a material effect on the IOUs' expansion plans, it could allow the IOUs to achieve increased fuel savings during other near-peak or forced outage events. Mr. Hinton also pointed out that increased activation of these cycling programs could be beneficial to the utilities in that it would allow them to gain operational experience, test the program infrastructure, and assess customer response to more frequent power curtailments.

Mr. Floyd testified that he had compared Duke's Power Manager and PEC's EnergyWise air conditioning cycling programs with programs in other states and jurisdictions to some extent. He called PEC's and Duke's programs "new age" in that they involve new technology, but pointed to a program in Maryland that allows the customer to choose a level of incentive based on the amount of air conditioning load control he is willing to cede to the utility. Mr. Floyd deemed programs with various levels of incentives as a potential opportunity for consideration by North Carolina's IOUs.

DNCP witness Venable testified that DNCP included an air conditioner cycling program in its initial DSM portfolio modeled for the 2009 Plan and will consider opportunities for lowering fuel costs once the program is approved in North Carolina and it can further analyze operational data. PEC witness Snider testified that PEC will investigate and evaluate optimal use of its EnergyWise residential air conditioning load control program, including consideration of its potential benefits as a capacity resource and as a tool to lower fuel costs.

The Commission finds that DSM resources should be optimized so as to obtain their maximum value. Accordingly, the IOUs are encouraged in their 2010 IRPs to consider their DSM resources' potential benefits, both as capacity resources and as a means of lowering fuel costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence supporting this finding of fact is contained in the Public Staff's comments filed on February 8, 2010, and the 2008 and 2009 IRP and 2009 REPS compliance plans of NCEMC, Piedmont, Blue Ridge, Rutherford, EU, Haywood, GreenCo, and Halifax.

On February 8, 2010, the Public Staff filed the only comments on the IRPs and REPS compliance plans filed by the non-IOU electric utilities. As part of its comments, the Public Staff addressed the IRPs filed by NCEMC, Piedmont, Rutherford, EU, and Haywood and the REPS compliance plans filed by GreenCo, Halifax, and EU in Docket No. E-100, Sub 124, pursuant to Rule R8-60.

The 2009 IRPs are, as described above, the annual updates to the 2008 IRPs. Therefore, consistent with Rule R8-60(h)(2), the Public Staff's comments addressed the non-IOUs' updated 15 year forecasts and significant amendments or revisions to their 2008 IRPs. The Public Staff's initial comments on the 2008 IRPs, filed April 24, 2009, and its reply comments filed May 27, 2009 (collectively, 2008 Comments), in Docket No. E-100, Sub 118 were incorporated by reference. Overall, the Public Staff found the IRPs and REPS compliance plans to be acceptable.

As noted in its comments, the Public Staff's analysis of NCEMC's peak load forecasting accuracy over the past five years indicates that the forecasts with DSM in its 2004 annual report were, on average, 332 MW lower than the actual system load, a 11% forecast error, whereas, its energy sales forecast has been more accurate with less than a 5% error rate. All of the peak load predictions from the 2004 Annual Plan have been less than the actual peak loads experienced. The Public Staff had noted this pattern of under-forecasting of peak loads in comments filed in previous IRP dockets. Since NCEMC does not weather normalize its peak loads, the Public Staff was unable to examine the accuracy of the forecasts excluding the effects of weather.

As it did in its comments in Docket No. E-100, Sub 118, the Public Staff continues to recommend that NCEMC examine its peak load forecasting models and assumptions for possible sources of bias leading to under-forecasting of peak loads, as well as other factors that may have contributed to the relatively large forecast errors. NCEMC is addressing this concern in two ways. First, it has informed the Public Staff that it intends to use a weather normalization methodology in its 2010 IRP. Second, NCEMC is evaluating other peak demand models. Both of these actions should assist NCEMC in improving its forecasting accuracy.

As noted on page 4 of its IRP, NCEMC completed a forecast in late 2009 that reflected the impact of the 2008/2009 economic recession. The new forecast indicates compound annual growth rates of 1.6% for summer peaks, 1.6% for winter peaks, and 1.3% for energy sales. The peak load forecasts are based on more current information than that available to NCEMC at the time of the filing of its 2009 IRP. The Public Staff believes NCEMC's updated forecast is more accurate in light of current conditions. Due to a lack of historical data, the accuracy of the forecasts of EU, Haywood, Piedmont, and Rutherford were not reviewed.

With the exception of Rutherford, the Public Staff believes the EMCs are developing new DSM/EE programs for their customers. Each EMC has continued to rely on its existing load control resources as its primary DSM/EE resources. The Public Staff was encouraged to see GreenCo develop a portfolio of DSM/EE resources that will be available to each of its participating members.

Based on the Public Staff's comments, and the Commission's review of the record in this proceeding, the Commission finds that the 2008 and 2009 IRPs and 2009 REPS compliance plans of NCEMC, Piedmont, Blue Ridge, Rutherford, EU, Haywood, GreenCo, and Halifax are reasonable and should be approved. The 2009 REPS compliance plans submitted in Docket No. E-100, Sub 124, completely supersede the 2008 REPS compliance plans submitted in Docket No. E-100, Sub 118.

Therefore, the Commission has not made any determination as to the acceptability of the 2008 plans.

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 2008 biennial reports and the 2009 annual updates to the 2008 biennial reports filed in this proceeding by the IOUs, NCEMC, Piedmont, Blue Ridge, Rutherford, EU, and Haywood are hereby approved.

3. That the 2009 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 respective utility's projected reserve margins.

5. That future IRP filings by all utilities shall 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: (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. If time constraints dictate, this information may be filed separately from the main body of the 2010 report.

7. That the IOUs shall continue to investigate increased reliance on air conditioning cycling load control and other DSM resources so as to obtain the maximum value from those resources.

8. That NCEMC shall examine its peak load forecasting models and assumptions for possible sources of bias leading to under-forecasting of peak loads, as well as other factors that may have contributed to the relatively large forecast errors in the past.

9. 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), 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.

ISSUED BY ORDER OF THE COMMISSION.

This the _10th___ day of August, 2010.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount

Gail L. Mount, Deputy Clerk

kh081010.01

Progress Energy - Carolinas

Table 1 2009 Annual IRP (Summer)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
GENERATION CHANGES															
Sited Additions		635		950											
Undesignated Additions (1)				126				169	338	1,105	1,105				169
Planned Project Uprates		18	57		10	14									
Pollution Control Derates			(5)												
Retirements - Lee 1, 2, 3				(397)											
INSTALLED GENERATION															
Nuclear	3,468	3,486	3,543	3,543	3,553	3,567	3,567	3,567	3,567	3,567	3,567	3,567	3,567	3,567	3,567
Fossil	5,179	5,179	5,175	4,778	4,778	4,778	4,778	4,778	4,778	4,778	4,778	4,778	4,778	4,778	4,778
Combined Cycle	543	1,178	1,178	2,128	2,128	2,128	2,128	2,128	2,128	2,128	2,128	2,128	2,128	2,128	2,128
Combustion Turbine	3,132	3,132	3,132	3,132	3,132	3,132	3,132	3,132	3,132	3,132	3,132	3,132	3,132	3,132	3,132
Hydro	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
Undesignated (1)				126	126	126	126	295	633	1,738	2,843	2,843	2,843	2,843	3,012
TOTAL INSTALLED *	**12,550**	**13,203**	**13,256**	**13,935**	**13,945**	**13,959**	**13,959**	**14,128**	**14,466**	**15,571**	**16,676**	**16,676**	**16,676**	**16,676**	**16,845**
PURCHASES & OTHER RESOURCES															
SEPA	95	95	95	109	109	109	109	109	109	109	109	109	109	109	95
NUG QF - Cogen															
NUG QF - Renewable **	25	25	28	35	40	19	19	19	23	23	23	23	23	24	24
NUG QF - Other															
AEP/Rockport 2															
Butler Warner			220	220	220	220	220	220							
Anson CT Tolling Purchase				336	336	336	336	336	336	336	336,	336	336	336	336
Broad River CT	829	829	829	829	829	829	829	829	829	829	829	339			
Southern CC Purchase - ST	150	150													
Southern CC Purchase - LT	150	150	150	150	150	150	150	150	150	150					
TOTAL SUPPLY RESOURCES	**13,799**	**14,452**	**14,578**	**15,613**	**15,629**	**15,621**	**15,622**	**15,791**	**15,912**	**17,017**	**17,972**	**17,482**	**17,144**	**17,144**	**17,299**
SYSTEM PEAK LOAD	12,731	12,913	13,099	14,122	14,361	14,624	14,854	15,091	15,316	15,557	15,808	16,061	16,317	16,576	16,840
Firm Sales	200	200	200	100	100	100	100	100	100	100	100	100	100	100	100
Energy Efficiency & Demand Response	502	636	797	882	963	1,043	1,126	1,210	1,290	1,365	1,427	1,474	1,519	1,561	1,600
System Firm Load after DSM	12,230	12,276	12,303	13,239	13,397	13,581	13,729	13,881	14,026	14,192	14,381	14,586	14,798	15,015	15,240
RESERVES (2)	1,569	2,175	2,275	2,374	2,231	2,040	1,893	1,909	1,886	2,826	3,591	2,896	2,346	2,129	2,059
Capacity Margin (3)	11%	15%	16%	15%	14%	13%	12%	12%	12%	17%	20%	17%	14%	12%	12%
Reserve Margin (4)	13%	18%	18%	18%	17%	15%	14%	14%	13%	20%	25%	20%	16%	14%	14%
ANNUAL SYSTEM ENERGY (GWh)	**66,137**	**66,762**	**67,937**	**69,224**	**70,397**	**71,581**	**72,703**	**73,850**	**74,916**	**75,951**	**77,108**	**78,293**	**79,586**	**80,855**	**82,140**

Notes:

* TOTAL INSTALLED includes Mod-24 unit rating changes.

** 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 MW 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 2009 Annual IRP (Winter)

	09/10	10/11	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
GENERATION CHANGES															
Sited Additions			694	950											
Undesignated Additions (1)				147					201	402	1,125	1,125			
Planned Project Uprates		4	35	32	10		18								
Pollution Control Derates	(22)			(5)											
Retirements - Lee 1, 2, 3				(417)											
INSTALLED GENERATION															
Nuclear	3,622	3,626	3,661	3,693	3,703	3,703	3,721	3,721	3,721	3,721	3,721	3,721	3,721	3,721	3,721
Fossil	5,274	5,274	5,274	4,853	4,853	4,853	4,853	4,853	4,853	4,853	4,853	4,853	4,853	4,853	4,853
Combined Cycle	626	626	1,320	2,270	2,270	2,270	2,270	2,270	2,270	2,270	2,270	2,270	2,270	2,270	2,270
Combustion Turbine	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647	3,647
Hydro	229	229	229	229	229	229	229	229	229	229	229	229	229	229	229
Undesignated (1)				147	147	147	147	147	348	750	1,875	3,000	3,000	3,000	3,000
TOTAL INSTALLED *	**13,398**	**13,402**	**14,131**	**14,839**	**14,849**	**14,849**	**14,867**	**14,867**	**15,068**	**15,470**	**16,595**	**17,720**	**17,720**	**17,720**	**17,720**
PURCHASES & OTHER RESOURCES															
SEPA	95	95	95	109	109	109	109	109	109	109	109	109	109	109	109
NUG QF - Cogen															
NUG QF - Renewable **	25	25	28	35	40	19	19	19	23	23	23	23	23	24	24
NUG QF - Other															
AEP/Rockport 2															
Butler Warner				260	260	260	260	260							
Anson CT Tolling Purchase				365	365	365	365	365	365	365	365	365	365	365	365
Broad River CT	822	822	822	822	822	822	822	822	822	822	822	822	329		
Southern CC Purchase - ST	150	150													
Southern CC Purchase - LT	150	150	150	150	150	150	150	150	150	150					
Undesignated Purchase															
TOTAL SUPPLY RESOURCES	**14,640**	**14,644**	**15,226**	**16,579**	**16,594**	**16,573**	**16,591**	**16,592**	**16,536**	**16,938**	**17,913**	**19,039**	**18,546**	**18,217**	**18,217**
SYSTEM PEAK LOAD	11,420	11,573	11,734	12,776	12,985	13,213	13,407	13,608	13,798	14,003	14,218	14,435	14,655	14,879	15,108
Firm Sales	200	200	100	100	100	100	100	100	100	100	100	100	100	100	100
Energy Efficiency & Demand Response	410	482	572	686	721	755	787	821	855	891	925	955	984	1,013	1,039
System Firm Load after DSM	11,009	11,091	11,162	12,090	12,264	12,458	12,620	12,786	12,943	13,112	13,293	13,481	13,671	13,866	14,069
RESERVES (2)	3,630	3,553	4,064	4,489	4,331	4,116	3,971	3,805	3,593	3,826	4,621	5,558	4,874	4,351	4,149
Capacity Margin (3)	25%	24%	27%	27%	26%	25%	24%	23%	22%	23%	26%	29%	26%	24%	23%
Reserve Margin (4)	33%	32%	36%	37%	35%	33%	31%	30%	28%	29%	35%	41%	36%	31%	29%

Notes:

* TOTAL INSTALLED includes Mod-24 unit rating changes.

** 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 MW 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.

Summer Projections of Load, Capacity, and Reserves for Duke Energy Carolinas 2009 Annual Plan

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Load Forecast																				
1 Duke System Peak	17,668	18,635	18,897	19,035	19,317	19,670	20,072	20,446	20,877	21,266	21,596	21,930	22,277	22,639	23,021	23,403	23,801	24,195	24,579	24,955
Reductions to Load Forecast																				
2 New EE Programs	(39)	(72)	(125)	(163)	(194)	(236)	(293)	(336)	(366)	(394)	(452)	(483)	(483)	(483)	(483)	(483)	(483)	(483)	(483)	(483)
3 Adjusted Duke System Peak	**17,629**	**18,562**	**18,772**	**18,871**	**19,124**	**19,434**	**19,779**	**20,109**	**20,511**	**20,871**	**21,144**	**21,447**	**21,794**	**22,156**	**22,538**	**22,920**	**23,318**	**23,712**	**24,096**	**24,472**
Cumulative System Capacity																				
4 Generating Capacity	19,915	19,916	19,966	20,773	21,137	21,155	21,018	20,966	20,833	20,833	20,833	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207
5 Capacity Additions	13	50	1,464	665	18	51	81	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	(12)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	0	0	(657)	(300)	0	(188)	(133)	(133)	0	0	(626)	0	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	19,916	19,966	20,773	21,137	21,155	21,018	20,966	20,833	20,833	20,833	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207
Purchase Contracts																				
9 Cumulative Purchase Contracts	767	893	906	734	769	451	475	473	487	518	528	544	612	628	648	666	163	163	163	163
Sales Contracts																				
10 Catawba Owner Backstand	(73)	(121)	(47)	(47)																
11 Catawba Owner Load Following Agreement	(23)	(23)																		
12 Cumulative Future Resource Additions																				
Base Load	0	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
Peaking/Intermediate	0	0	0	0	0	0	632	1,264	1,264	1,896	2,528	2,528	2,528	2,528	2,528	2,528	3,160	3,792	4,424	4,464
Renewables	14	27	171	175	179	183	220	224	318	337	371	405	420	420	420	435	435	458	458	458
13 Cumulative Production Capacity	**20,601**	**20,742**	**21,802**	**21,999**	**22,103**	**21,652**	**22,293**	**22,794**	**22,902**	**23,584**	**23,634**	**24,801**	**24,884**	**26,017**	**26,037**	**26,070**	**26,199**	**26,854**	**27,486**	**27,526**
Reserves w/o Demand-Side Management																				
14 Generating Reserves	2,972	2,180	3,030	3,128	2,979	2,218	2,514	2,685	2,391	2,713	2,490	3,354	3,090	3,861	3,499	3,151	2,881	3,142	3,390	3,053
15 % Reserve Margin	**16.9%**	**11.7%**	**16.1%**	**16.6%**	**15.6%**	**11.4%**	**12.7%**	**13.4%**	**11.7%**	**13.0%**	**11.8%**	**15.6%**	**14.2%**	**17.4%**	**15.5%**	**13.7%**	**12.4%**	**13.2%**	**14.1%**	**12.5%**
16 % Capacity Margin	14.4%	10.5%	13.9%	14.2%	13.5%	10.2%	11.3%	11.8%	10.4%	11.5%	10.5%	13.5%	12.4%	14.8%	13.4%	12.1%	11.0%	11.7%	12.3%	11.1%
Demand-Side Management																				
17 Cumulative DSM Capacity	750	965	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
IS / SG	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293
Power Share / Power Manager	457	672	807	807	807	807	807	807	807	807	807	807	807	807	807	807	807	807	807	807
18 Cumulative Equivalent Capacity	21,351	21,707	22,902	23,099	23,203	22,752	23,393	23,894	24,002	24,684	24,734	25,901	25,984	27,117	27,137	27,170	27,299	27,954	28,586	28,626
Reserves w/ DSM																				
19 Generating Reserves	3,722	3,145	4,130	4,228	4,079	3,318	3,614	3,785	3,491	3,813	3,590	4,454	4,190	4,961	4,599	4,251	3,981	4,242	4,490	4,153
20 % Reserve Margin	**21.1%**	**16.9%**	**22.0%**	**22.4%**	**21.3%**	**17.1%**	**18.3%**	**18.8%**	**17.0%**	**18.3%**	**17.0%**	**20.8%**	**19.2%**	**22.4%**	**20.4%**	**18.6%**	**17.1%**	**17.9%**	**18.6%**	**17.0%**
21 % Capacity Margin	17.4%	14.5%	18.0%	18.3%	17.6%	14.6%	15.4%	15.8%	14.5%	15.4%	14.5%	17.2%	16.1%	18.3%	16.9%	15.6%	14.6%	15.2%	15.7%	14.5%

Winter Projections of Load, Capacity, and Reserves for Duke Energy Carolinas 2009 Annual Plan

	09/10	10/11	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
Load Forecast																				
1 Duke System Peak	16,165	16,526	17,282	17,427	17,678	17,974	18,312	18,627	18,976	19,295	19,558	19,821	20,097	20,391	20,702	21,013	21,345	21,663	21,974	22,279
Reductions to Load Forecast																				
2 New EE Programs	(29)	(71)	(103)	(177)	(210)	(254)	(348)	(344)	(409)	(438)	(472)	(599)	(555)	(555)	(555)	(555)	(555)	(555)	(555)	(555)
3 Adjusted Duke System Peak	**16,136**	**16,454**	**17,180**	**17,249**	**17,469**	**17,720**	**17,964**	**18,283**	**18,566**	**18,857**	**19,086**	**19,222**	**19,542**	**19,836**	**20,147**	**20,458**	**20,790**	**21,108**	**21,419**	**21,724**
Cumulative System Capacity																				
4 Generating Capacity	20,766	20,638	20,639	20,689	21,495	21,860	21,878	21,740	21,688	21,555	21,555	21,555	20,929	20,929	20,929	20,929	20,929	20,929	20,929	20,929
5 Capacity Additions	13	13	50	1,464	665	18	51	81	0	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	(141)	(12)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	0	0	0	(657)	(300)	0	(188)	(133)	(133)	0	0	(626)	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	20,638	20,639	20,689	21,495	21,860	21,878	21,740	21,688	21,555	21,555	21,555	20,929	20,929	20,929	20,929	20,929	20,929	20,929	20,929	20,929
Purchase Contracts																				
9 Cumulative Purchase Contracts	870	900	913	734	769	451	475	473	487	518	528	544	612	628	648	666	163	163	163	163
Sales Contracts																				
10 Catawba Owner Backstand	(73)	(121)	(47)	(47)																
11 Catawba Owner Load Following Agreement	(23)	(23)																		
12 Cumulative Future Resource Additions																				
Base Load	0	0	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
Peaking/Intermediate	0	0	0	0	0	0	0	632	1,264	1,264	1,896	2,528	2,528	2,528	2,528	2,528	2,528	3,160	3,792	4,424
Renewables	3	14	27	171	175	179	183	220	224	318	337	371	405	420	420	420	435	435	458	458
13 Cumulative Production Capacity	**21,415**	**21,409**	**21,581**	**22,353**	**22,804**	**22,508**	**22,399**	**23,014**	**23,531**	**23,656**	**24,317**	**24,373**	**25,592**	**25,623**	**26,760**	**26,778**	**26,290**	**26,922**	**27,576**	**28,208**
Reserves w/o Demand-Side Management																				
14 Generating Reserves	5,278	4,955	4,401	5,104	5,335	4,788	4,435	4,730	4,964	4,799	5,231	5,151	6,050	5,787	6,613	6,320	5,500	5,814	6,157	6,484
15 % Reserve Margin	**32.7%**	**30.1%**	**25.6%**	**29.6%**	**30.5%**	**27.0%**	**24.7%**	**25.9%**	**26.7%**	**25.5%**	**27.4%**	**26.8%**	**31.0%**	**29.2%**	**32.8%**	**30.9%**	**26.5%**	**27.5%**	**28.7%**	**29.8%**
16 % Capacity Margin	24.6%	23.1%	20.4%	22.8%	23.4%	21.3%	19.8%	20.6%	21.1%	20.3%	21.5%	21.1%	23.6%	22.6%	24.7%	23.6%	20.9%	21.6%	22.3%	23.0%
Demand-Side Management																				
17 Cumulative DSM Capacity	521	711	835	835	835	835	835	835	835	835	835	835	835	835	835	835	835	835	835	835
IS / SG	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293
Power Share / Power Manager	228	418	542	542	542	542	542	542	542	542	542	542	542	542	542	542	542	542	542	542
18 Cumulative Equivalent Capacity	21,936	22,120	22,416	23,188	23,639	23,343	23,234	23,849	24,366	24,491	25,152	25,208	26,427	26,458	27,595	27,613	27,125	27,757	28,411	29,043
Reserves w/ DSM																				
19 Generating Reserves	5,799	5,666	5,236	5,939	6,170	5,623	5,270	5,565	5,799	5,634	6,066	5,986	6,885	6,622	7,448	7,155	6,335	6,649	6,992	7,319
20 % Reserve Margin	**35.9%**	**34.4%**	**30.6%**	**34.4%**	**35.3%**	**31.7%**	**29.3%**	**30.4%**	**31.2%**	**29.9%**	**31.8%**	**31.1%**	**35.2%**	**33.4%**	**37.0%**	**35.0%**	**30.5%**	**31.5%**	**32.6%**	**33.7%**
21 % Capacity Margin	26.4%	25.6%	23.4%	25.6%	26.1%	24.1%	22.7%	23.3%	23.8%	23.0%	24.1%	23.7%	26.1%	25.0%	27.0%	25.9%	23.4%	24.0%	24.6%	25.2%

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 103 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for NCMPA1 firm capacity sale.
Generating Capacity also reflects a 277 MW reduction in Catawba Nuclear Station to account for PMPAs termination of their interconnection agreement with Duke Energy Carolinas.

5. Capacity Additions reflect an estimated 50 MW capacity uprate at the Jocassee pumped storage facility from increased efficiency from the new runners, a 36 MW increase in Belews Creek capacity due to LP rotor changeouts, and an 8.75 MW increase in capacity at Bridgewater Hydro by summer 2012.
The 150 MW addition in Catawba Nuclear Station resulting from the Saluda River acquisition was completed in September of 2008. However, there was no change to Catawba's capacity due to this acquition. Saluda River's portion of load associated with Catawba has historically been modeled within Duke Energy's load projections. Therefore, Saluda's ownership in Catawba has also been included in the Existing Capacity for Load, Capacity and Reserves reporting.
Capacity Additions include Duke Energy Carolinas projects that have been approved by the NCUC (Cliffside 6, Buck and Dan River Combined Cycle facilities).
Also included is a 205 MW capacity increase due to nuclear uprates at Catawba, McGuire, and Oconee Timing of these uprates are shown from 2012-2016

6. The expected Capacity Derates reflect the impact of parasitic loads from planned scrubber additions to various Duke fossil generating units. The units, in order of time sequence on the LCR table is Allen 1 - 5 followed by Cliffside 5.

7. The 657 MW capacity retirement in summer 2012 represents the projected retirement dates for Buck 3-4 (113 MW), Cliffside units 1-4 (198 MW), and 346 MW of old fleet CTs.
The 300 MW capacity retirement in summer 2013 represents the projected retirement date for Dan River Steam Station (276) and 24 MWs of old fleet CT retirements.
The 188 MW capacity retirement in summer 2015 represents the projected retirement date for Riverbend 4 and 5.
The 133 MW capacity retirement in summer 2016 represents the projected retirement date for Riverbend 6.
The 133 MW capacity retirement in summer 2017 represents the projected retirement date for Riverbend 7.
The 626 MW capacity retirement in summer 2020 represents the projected retirement date for Buck 5-6 (256 MW) and Lee Steam Station 1-3 (370 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.

10-11. Two firm wholesale agreements are effective between Duke Energy Carolinas and NCMPA1. The first is a 23 MW load following agreement that expires year-end 2010. The second is a backstand agreement of up to 432 MW (depending on operation of the Catawba and McGuire facilities) that was extended through 2010.

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 22 MW.
C. Purchase of 151 MW from Rowan Unit 2 began January 1, 2006 and expires December 31, 2010.
D. Purchase of 153 MW from Rowan Unit 1 began June 1, 2007 and expires December 31, 2010.
E. Purchase of 153 MW from Rowan Unit 3 began June 1, 2008 and expires December 31, 2010.

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

Schedule 1

I. PEAK LOAD AND ENERGY FORECAST

	(ACTUAL) [1]			(PROJECTED)															
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
1. Utility Peak Load (MW)																			
A. Summer																			
1a. Base Forecast	17,046	17,305	16,758	16,368	16,632	17,274	17,612	18,082	18,616	19,022	19,406	19,784	20,054	20,457	21,021	21,440	21,841	22,251	22,544
1b. Additional Forecast																			
BTMG				158	158	158	155	152	147	143	141	141	141	141	141	141	141	121	121
NCEMC	150	150	150	150	150	150	150	150	150	0	0	0	0	0	0	0	0	0	0
2. Conservation, Efficiency				0	0	0	-31	-106	-170	-192	-200	-207	-210	-212	-215	-217	-220	-222	-224
3. Demand-Side and Response				-14	-44	-100	-181	-273	-369	-435	-495	-551	-595	-627	-654	-677	-692	-705	-716
4. Demand-Side and Response-Existing [2]	21	23	22	22	21	19	17	16	15	15	15	15	15	15	15	15	15	15	15
5. Peak Adjustment				28	12	-52	276	-16	-16	-15	-15	-15	-15	-15	-15	-15	-15	-13	-13
6. Adjusted Load	17,196	17,455	16,908	16,704	16,952	17,530	18,163	18,261	18,727	18,958	19,332	19,703	19,970	20,371	20,932	21,349	21,747	22,137	22,428
7. % Increase in Adjusted Load (from previous year)		1.5%	-3.1%	-1.2%	1.5%	3.4%	3.6%	0.5%	2.5%	1.2%	2.0% l.	9%	1.4%:2.	0%:2.8	%	2.0% l.9	%	1.8% l.3	%
B. Winter																			
1. Base Forecast	14,294	15,910	14,985	14,288	14,295	14,582	14,864	15,370	15,748	16,024	16,327	16,525	16,950	17,284	17,630	17,967	18,216	18,551	18,999
1b. Additional Forecast																			
BTMG				158	158	158	155	152	147	143	141	141	141	141	141	141	141	121	121
NCEMC	150	150	150	150	150	150	150	150	150	0	0	0	0	0	0	0	0	0	0
2. Conservation, Efficiency				0	0	0	-29	-95	-141	-154	-159	-165	-167	-168	-170	-172	-174	-176	-178
3. Demand-Side and Response				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5. Adjusted Load	14,444	16,060	15,135	14,596	14,603	14,890	15,141	15,578	15,903	16,013	16,309	16,501	16,924	17,257	17,600	17,936	18,182	18,496	18,942
6. % Increase in Adjusted Load		11.2%	-5.8%	-3.6%	0.0%	2.0%	1.7%	2.9%	2.1%	0.7%	1.8% l.	2%	2.6%:2.	0%:2.0	%	1.9% l.4	%	1.7%:2.4	%
2. Energy (GWh)																			
A. Base Forecast	82,983	87,755	85,798	81,993	83,114	86,388	89,604	92,195	94,471	96,460	98,729	100,518	102,621	104,895	107,494	109,519	111,813	114,135	116,795
B. Additional Forecast																			
BTMG				1,386	1,386	1,386	1,363	1,319	1,282	1,255	1,238	1,235	1,235	1,235	1,238	1,235	1,235	1,064	1,181
NCEMC				590	605	619	645	658	676	0	0	0	0	0	0	0	0	0	0
ODECsupp				161	119	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C. PJM Energy Efficiency				-17	-18	-18	-19	-19	-20	-20	-21	-21	-22	-22	-23	-23	-24	-24	-25
D. Conservation & Demand Response				-94	-521	-1,293	-2,127	-2,866	-3,079	-3,158	-3,194	-3,231	-3,242	-3,252	-3,263	-3,273	-3,283	-3,293	-3,304
E. Adjusted Energy	82,983	87,755	85,798	84,018	84,685	87,082	89,467	91,287	93,329	94,537	96,752	98,500	100,592	102,856	105,447	107,458	109,741	111,882	114,647
F. % Increase in Adjusted Energy		5.8%	-2.2%	-2.1%	0.8%	2.8%	2.7%	2.0%	2.2%	1.3%	2.3% l.	8%	2.1%:2.	2%:2.5	%	1.9%:2.1	%	2.0%:2.5	%

(1) 88% of zonal load
(2) Existing DSM programs are included in the load forecast

APPENDIX 2I – REQUIRED RESERVE MARGIN

Company Name: Virginia Electric and Power Company

Schedule 6

POWER SUPPLY DATA (continued)

	(ACTUAL)				(PROJECTED)														
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
I. Reserve Margin [1]																			
(Including Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW [1]	645	494	1,312	3,476	2,947	2,821	3,040	2,191	2,247	2,275	2,320	2,365	2,397	2,445	2,512	2,562	2,610	2,657	2,693
b. Percent of Load	3.8%	2.9%	7.8%	21.3%	17.4%	16.1%	16.7%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
c. Actual Reserve Margin [4]	N/A	N/A	N/A	10.17%	8.9%	9.6%	9.0%	10.3%	7.7%	6.9%	8.6%	6.4%	11.2%	10.1%	8.6%	8.6%	9.6%	10.5%	11.9%
2. Winter Reserve Margin																			
a. MW [1]	N/A	N/A	N/A	N/A	7,236	7,241	7,911	6,632	6,809	7,520	7,439	8,506	7,877	8,183	8,458	8,788	8,883	9,035	8,928
b. Percent of Load	N/A	N/A	N/A	N/A	49.6%	48.6%	52.2%	42.6%	42.8%	47.0%	45.6%	51.5%	46.5%	47.4%	48.1%	49.0%	48.9%	48.9%	47.1%
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]	708	494	1,312	3,476	2,947	2,821	3,040	2,191	2,247	2,275	2,320	2,365	2,397	2,445	2,512	2,562	2,610	2,657	2,693
b. Percent of Load	3.0%	2.9%	7.8%	21.3%	17.4%	16.1%	16.7%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%
c. Actual Reserve Margin [4]	N/A	N/A	N/A	10.2%	8.9%	9.6%	9.0%	10.3%	7.7%	6.9%	8.6%	6.4%	11.2%	10.1%	8.6%	8.6%	9.6%	10.5%	11.9%
2. Winter Reserve Margin																			
a. MW [1]	N/A	N/A	N/A	N/A	7,236	7,241	7,911	6,632	6,809	7,520	7,439	8,506	7,877	8,183	8,458	8,788	8,883	9,035	8,928
b. Percent of Load	N/A	N/A	N/A	N/A	49.6%	48.6%	52.2%	42.6%	42.8%	47.0%	45.6%	51.5%	46.5%	47.4%	48.1%	49.0%	48.9%	48.9%	47.1%
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 no units in Cold Reserve past 2006

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

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Load Requirements															
20 EMC Demand (1)	2,891	2,962	3,027	3,102	3,173	3,245	3,321	3,398	3,478	3,560	3,649	3,738	3,827	3,918	4,012
Existing DSM (2)	73	68	68	68	68	68	68	68	68	68	68	68	68	68	68
Net Peak Demand	2,819	2,895	2,959	3,034	3,105	3,177	3,253	3,330	3,410	3,493	3,581	3,671	3,760	3,851	3,945
Capacity Resources															
Catawba (3)	682	682	682	682	682	682	682	682	682	682	682	682	682	682	682
NCEMC CTs	623	623	623	623	623	623	623	623	623	623	623	623	623	623	623
Diesels	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Total Capacity Resources	1,323	1,323	1,323	1,323	1,323	1,323	1,323	1,323	1,323	1,323	1,323	1,323	1,323	1,323	1,323
Purchased Resources (4)															
AEP Purchases	355	150	150	0	0	0	0	0	0	0	0	0	0	0	0
PEC SORs	870	870	870	920	970	970	970	970	970	970	550	375	225	0	0
PEC PPAs	350	350	300	1,140	1,130	1,165	1,200	1,235	1,271	1,306	1,759	1,969	2,154	2,415	2,453
Duke PPAs	97	97	97	97	97	97	122	122	122	122	147	147	147	147	147
Southern PPAs	0	0	225	225	225	225	225	270	270	360	360	360	360	360	360
SCE&G PPA	250	250	250	0	0	0	0	0	0	0	0	0	0	0	0
Dominion PPA	150	150	150	150	150	0	0	0	0	0	0	0	0	0	0
SEPA Allocations (5)	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
PJM UCAP (9)	110	114	118	39	40	131	136	140	144	147	152	156	160	164	168
Total Purchased Resources	2,254	2,053	2,232	2,644	2,683	2,661	2,726	2,809	2,848	2,978	3,040	3,079	3,118	3,158	3,200
Obligations															
Capacity Sale to Independent Members	499	376	376	261	262	218	218	218	218	218	211	208	205	201	201
Southern PSA	0	0	100	100	100	100	100	100	100	100	100	100	0	0	0
PEC Tolling	0	0	0	336	336	336	336	336	336	336	336	336	336	336	336
Reserves (6)	81	81	99	55	55	55	55	60	60	72	72	72	84	84	84
Net Resources for Participating Members	2,996	2,919	2,980	3,214	3,253	3,275	3,339	3,418	3,457	3,575	3,644	3,686	3,816	3,860	3,902
Undesignated DSM / EE Resources (7)	11	22	32	44	57	71	84	97	97	97	97	97	97	97	97
Undesignated Renewable Resources (7)	0	2	2	9	15	17	25	26	26	83	111	115	120	126	126
Undesignated Future Conventional Resources	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual Energy (GWh) (8)	12,822	13,229	13,625	14,022	14,343	14,674	15,014	15,365	15,728	16,106	16,499	16,906	17,325	17,845	18,287
Annual Energy after EE (GWh) (8)	12,761	13,119	13,464	13,807	14,069	14,337	14,614	14,903	15,266	15,644	16,038	16,445	16,863	17,383	17,826

Notes:

(1) Total Demand is NCEMC's Participating Member coincident peak (NCEMC CP) measured at generation.

(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) NCEMC assumes all capacity purchases will be 100% firm with reserves provided by the supplying entity.

(5) SEPA Allocations are for Participating Members

(6) Reserves included for NCEMC CTs and Southern purchases as applicable.

(7) Undesignated DSM / Energy Efficiency & Renewable resources included in NCEMC's 2008 IRP.

(8) Energy values are measured at generation for Participating Members.

Table 4.2 NCEMC Projected Winter Load and Capacity (values in MW unless noted otherwise)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Load Requirements															
20 EMC Demand (1)	2,864	2,935	3,001	3,076	3,144	3,217	3,289	3,364	3,443	3,525	3,610	3,697	3,785	3,875	3,967
Existing DSM (2)	66	64	64	64	64	64	64	64	64	64	64	64	64	64	64
Net Peak Demand	2,798	2,871	2,937	3,012	3,080	3,153	3,225	3,301	3,380	3,461	3,547	3,633	3,721	3,811	3,903
Capacity Resources															
Catawba (3)	682	682	682	682	682	682	682	682	682	682	682	682	682	682	682
NCEMC CTs	673	673	673	673	673	673	673	673	673	673	673	673	673	673	673
Diesels	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Total Capacity Resources	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373
Purchased Resources (4)															
AEP Purchases	355	150	150	0	0	0	0	0	0	0	0	0	0	0	0
PEC SORs	870	870	870	920	970	970	970	970	970	970	550	375	225	0	0
PEC PPAs	350	350	300	1,140	1,130	1,165	1,200	1,235	1,271	1,306	1,759	1,969	2,154	2,415	2,453
Duke PPAs	97	97	97	97	97	97	122	122	122	122	147	147	147	147	147
Southern PPAs	0	0	225	225	225	225	225	270	270	360	360	360	360	360	360
SCE&G PPA	250	250	250	0	0	0	0	0	0	0	0	0	0	0	0
Dominion PPA	150	150	150	150	150	0	0	0	0	0	0	0	0	0	0
SEPA Allocations (5)	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
PJM UCAP (9)	110	114	118	39	40	131	136	140	144	147	152	156	160	164	168
Total Purchased Resources	2,254	2,053	2,232	2,644	2,683	2,661	2,726	2,809	2,848	2,978	3,040	3,079	3,118	3,158	3,200
Obligations															
Capacity Sale to Independent Members	499	376	376	261	262	218	218	218	218	218	211	208	205	201	201
Southern PSA	0	0	100	100	100	100	100	100	100	100	100	100	0	0	0
PEC Tolling	0	0	0	367	367	367	367	367	367	367	367	367	367	367	367
Reserves (6)	88	88	106	58	58	58	58	63	63	75	75	75	87	87	87
Net Resources for Participating Members	3,040	2,962	3,023	3,230	3,269	3,291	3,355	3,434	3,473	3,591	3,660	3,702	3,832	3,876	3,918
Undesignated DSM / EE Resources (7)	11	22	32	44	57	71	84	97	97	97	97	97	97	97	97
Undesignated Renewable Resources (7)	0	2	2	9	15	17	25	26	26	83	111	115	120	126	126
Undesignated Future Conventional Resources	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual Energy (GWh) (8)	12,822	13,229	13,625	14,022	14,343	14,674	15,014	15,365	15,728	16,106	16,499	16,906	17,325	17,845	18,287
Annual Energy after EE (GWh) (8)	12,761	13,119	13,464	13,807	14,069	14,337	14,614	14,903	15,266	15,644	16,038	16,445	16,863	17,383	17,826

Notes:

(1) Total Demand is NCEMC's Participating Member coincident peak (NCEMC CP) measured at generation.

(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) NCEMC assumes all capacity purchases will be 100% firm with reserves provided by the supplying entity.

(5) SEPA Allocations are for Participating Members

(6) Reserves included for NCEMC CTs and Southern purchases as applicable.

(7) Undesignated DSM / Energy Efficiency & Renewable resources included in NCEMC's 2008 IRP.

(8) Energy values are measured at generation for Participating Members.

(9) PJM UCAP purchases include estimated market reserve requirements

Table 1.2: Piedmont EMC Projected Summer Peak Loads, Resources and Annual Energy (2009 Load Forecast)

Piedmont EMC - Duke Control Area

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
PEAK (MW) (1)	99	101	103	105	107	109	111	113	115	117	119	121	123	125	127
ANNUAL ENERGY (GWh) (1)	424	432	441	450	458	466	474	482	490	499	508	516	525	534	543

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 full requirements agreement with Duke Power Company, LLC, thus Piedmont's loads and resources are integrated into Duke Power's 2009 Integrated Resource Plan. The initial term of the FRA with Duke Power is January 1, 2008 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

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Load Requirements:															
PEAK (MW) (1)	28	28	29	29	30	30	31	31	32	33	33	34	34	35	36
Purchased Resources: (2)															
NCEMC WPSA	10	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	1
Progress Energy Purchases (3)	17	21	22	23	24	24	25	25	26	27	27	28	28	29	30
TOTAL RESOURCES (MW)	28	28	29	29	30	30	31	31	32	33	33	34	34	35	36
RESERVE CAPACITY (MW) (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL ENERGY (GWh) (1)	118	121	123	126	128	130	132	135	137	139	142	144	147	149	152

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

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
PEAK (MW) (1)	127	129	132	134	137	139	141	144	147	149	152	154	157	160	163
ANNUAL ENERGY (GWh) (1)	542	553	564	576	586	596	606	617	627	638	649	661	672	683	695
ANNUAL ENERGY (GWh) (1) (Including Impact of Energy Efficiency Programs)	538	548	556	565	573	580	588	597	607	618	629	640	652	663	675

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

Table 1.3: Piedmont EMC Projected Winter Peak Loads, Resources and Annual Energy (2009 Load Forecast)

Piedmont EMC - Duke Control Area

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
PEAK (MW) (1)	101	103	105	107	109	111	113	115	117	119	121	123	125	127	130
ANNUAL ENERGY (GWh) (1)	424	432	441	450	458	466	474	482	490	499	508	516	525	534	543

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 full requirements agreement with Duke Power Company, LLC, thus Piedmont's loads and resources are integrated into Duke Power's 2009 Integrated Resource Plan. The initial term of the FRA with Duke Power is January 1, 2008 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

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Load Requirements:															
PEAK (MW) (1)	28	29	29	30	30	31	32	32	33	33	34	34	35	36	36
Purchased Resources: (2)															
NCEMC WPSA	10	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	1
Progress Energy Purchases (3)	17	22	22	24	24	25	26	26	27	27	28	28	29	30	30
TOTAL RESOURCES (MW)	28	29	29	30	30	31	32	32	33	33	34	34	35	36	36
RESERVE CAPACITY (MW) (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL ENERGY (GWh) (1)	118	121	123	126	128	130	132	135	137	139	142	144	147	149	152

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

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
PEAK (MW) (1)	129	132	134	137	139	142	144	147	149	152	155	158	160	163	166
ANNUAL ENERGY (GWh) (1)	542	553	564	576	586	596	606	617	627	638	649	661	672	683	695
ANNUAL ENERGY (GWh) (1) (Including Impact of Energy Efficiency Programs)	538	548	556	565	573	580	588	597	607	618	629	640	652	663	675

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

Table 1.2: Rutherford EMC Projected Summer Peak Load, Resources and Annual Energy (2009 Load Forecast)

Rutherford EMC

Load Requirements:	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
PEAK (MW) (1)	282	285	288	291	294	297	300	303	306	309	313	317	320	324	328
Purchased Resources: (2)															
NCEMC WPSA	116	84	84	57	57	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
Morgan Stanley Purchases (3)	87	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Duke Power Purchases (4)	55	177	180	210	213	226	229	232	235	238	242	246	249	253	257
TOTAL RESOURCES (MW)	282	285	288	291	294	297	300	303	306	309	313	317	320	324	328
RESERVE CAPACITY (MW) (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL ENERGY (GWh) (5)	1,336	1,349	1,363	1,375	1,388	1,400	1,413	1,425	1,439	1,452	1,468	1,482	1,498	1,513	1,530

1. Peak is Rutherford's peak measured at generation.
2. All purchases are 100% firm with reserves provided by the supplying entity.
3. The term of the initial purchase with Morgan Stanley is 7 years beginning in 2004. All current and future resources provided by Morgan Stanley are firm; Resources provided by Morgan will come from resources in the Duke control area or through imports made with firm transmission at interties with Southern, AEP, and Yadkin.
4. The initial term of the purchase with Duke Power 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 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 Rutherford's demand-side programs, therefore the MWs associated with these programs are considered a Duke resource.
5. Energy values are measured at generation.

Table 1.3: Rutherford EMC Projected Winter Peak Load, Resources and Annual Energy (2009 Load Forecast)

Rutherford EMC	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Load Requirements:															
PEAK (MW) (1)	314	317	321	324	327	331	334	337	341	345	348	352	356	360	365
Purchased Resources: (2)															
NCEMC WPSA	116	84	84	57	57	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
Morgan Stanley Purchases (3)	95	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Duke Power Purchases (4)	79	209	213	243	246	260	263	266	270	274	277	281	285	289	294
TOTAL RESOURCES (MW)	314	317	321	324	327	331	334	337	341	345	348	352	356	360	365
RESERVE CAPACITY (MW) (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL ENERGY (GWh) (5)	1,336	1,349	1,363	1,375	1,388	1,400	1,413	1,425	1,439	1,452	1,468	1,482	1,498	1,513	1,530

1. Peak is Rutherford's peak measured at generation.
2. All purchases are 100% firm with reserves provided by the supplying entity.
3. The term of the initial purchase with Morgan Stanley is 7 years beginning in 2004. All current and future resources provided by Morgan Stanley are firm; Resources provided by Morgan will come from resources in the Duke control area or through imports made with firm transmission at interties with Southern, AEP, and Yadkin.
4. The initial term of the purchase with Duke Power 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 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 Rutherford's demand-side programs, therefore the MWs associated with these programs are considered a Duke resource.
5. Energy values are measured at generation.

2009 ncuc IRP filings
summer (Table 1.2)

Table 1.2: EnergyUnited Total Projected Summer Load and Capacity (2009 Load Forecast)

EnergyUnited

	LOCATION	FUEL SOURCE	CAPACITY DESIGNATION	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Load Requirements:																		
PEAK BEFORE ANTICIPATED ENERGY EFFICIENCY PROGRAMS (MW) (1)				566.3	578.0	580.2	584.0	594.1	607.5	621.3	635.5	650.2	666.2	682.5	699.0	716.0	733.4	751.3
Less: Impact of anticipated energy efficiency programs				(0.3)	(1.4)	(4.8)	(7.5)	(10.5)	(10.6)	(12.5)	(12.6)	(12.6)	(12.7)	(12.8)	(12.9)	(13.0)	(13.1)	(13.3)
PEAK NET OF ANTICIPATED ENERGY EFFICIENCY PROGRAMS				566.0	576.6	575.3	576.5	583.5	596.9	608.8	623.0	637.5	653.5	669.6	686.1	703.0	720.3	738.1
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	79.0
AEP Purchase	Duke Control Area	Coal	Base	26.0														
CP&L SOR A	Duke Control Area	Mix	Base	29.0														
SCE&G Intermediate Resouce	Duke Control Area	Gas	Intermediate	32.0	32.0	32.0												
AEP Baseload Resource	Duke Control Area	Mix	Base	19.0	19.0	19.0												
Dominion PPA	Duke Control Area	Mix	Intermediate	19.0	19.0	19.0	19.0	19.0										
Total NCEMC Existing Resources				204.0	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
SEPA	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	16.0
Morgan Stanley Purchases (3)																		
Total Morgan Stanley Purchases	Various	Mix	Base/Intermediate/Peaking	265.0														
Southern Power/Southern Company Purchases (4)																		
Total Southern Purchases	Various	Mix	Base/Intermediate/Peaking	81.0	411.6	410.3	462.5	469.5	501.9	513.8	528.0	542.5	558.5	574.6	591.1	608.0	625.3	643.1
TOTAL RESOURCES (MW)				566.0	576.6	575.3	576.5	583.5	596.9	608.8	623.0	637.5	653.5	669.6	686.1	703.0	720.3	738.1
RESERVE CAPACITY (MW) (4)			15% of EnergyUnited Peak	85.0	86.7	87.0	87.6	89.1	91.1	93.2	95.3	97.5	99.9	102.4	104.9	107.4	110.0	112.7
REPS Resources																		
ANNUAL ENERGY BEFORE ENERGY EFFICIENCY PROGRAMS(GWH) (5)				2,506.1	2,527.5	2,551.9	2,591.9	2,645.7	2,701.0	2,757.9	2,816.3	2,876.3	2,937.4	2,999.5	3,063.3	3,128.9	3,196.2	3,265.4
Less: Impact of anticipated energy efficiency programs				(0.8)	(2.0)	(45.9)	(70.7)	(99.3)	(99.6)	(116.3)	(117.1)	(117.8)	(118.7)	(119.5)	(120.4)	(121.3)	(122.2)	(123.2)
NET ANNUAL ENERGY				2,505.2	2,525.5	2,506.0	2,521.3	2,546.4	2,601.4	2,641.5	2,699.2	2,758.5	2,818.7	2,880.0	2,942.9	3,007.6	3,074.0	3,142.2
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
Anticipated Solar Resources	TBD	Solar	N/A	1.0	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
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
Other Anticipated Renewable Resources (TBD)	TBD	TBD				4.5	4.7	4.9	5.0	13.4	13.7	14.1	31.9	33.0	34.1	35.2	36.3	38.0
Total Anticipated Renewable Capacity				20.0	20.0	24.5	24.7	24.9	26.0	34.4	34.7	35.1	53.9	55.0	56.1	57.2	58.3	60.0
Energy from renewable resources (GWH):	REC's Carried Forward																	
Iredell Transmission LLC	32			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
Anticipated Solar Resources				0.8	1.8	1.8	1.8	1.8	2.6	2.6	2.6	2.6	3.9	3.9	3.9	3.9	3.9	3.9
SEPA	21			21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Nextera Wind REC's(Out of State)	150																	
Salem Energy Systems LLC REC's	60			30.0														
Other Renewable Resources/REC's needed											53.6	239.0	243.8	250.0	256.4	263.0	269.7	276.6
Demand Side Management (6)																		
DEMAND SIDE MANAGEMENT PROGRAMS:(activated during peak hours)	# Customers	Demand Reduction(MW)	Hours in DSM															
Residential Water Heaters	23,659	7.56	98 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	98 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	98 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

2008 Peak- June 9th, 2008 HE 6:00pm --558 MW
2009 Peak- August 10th, 2009 HE 3:00pm --510 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 term of the initial purchase with Morgan Stanley is 7 years beginning in 2004. All current and future resources provided by Morgan Stanley are firm; the Morgan Stanley purchase is a network resource recognized by Duke Transmission. Resources provided by Morgan to serve load in the Duke control area will come from resources in the Duke control area or through imports made with firm transmission at interties with Southern, AEP, and Yadkin. These firm transmission purchases have been designated in the application with the transmission provider.
4. 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 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
5. Energy values are measured at generation.
6. Demand Side Management allows us to reduce 21MW during peak periods at our option using load management devices and backup generation.

2009 ncuc IRP filings
winter (Table 1.3)

Table 1.3: EnergyUnited Total Projected Winter Load and Capacity (2009 Load Forecast)

EnergyUnited

	LOCATION	FUEL SOURCE	CAPACITY DESIGNATION	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Load Requirements:																		
PEAK BEFORE ENERGY EFFICIENCY PROGRAMS (MW) (1) (6)				577.7	579.4	582.0	586.8	599.7	613.0	626.7	640.8	655.3	670.2	685.2	700.5	716.4	732.7	749.4
Less: Impact of anticipated energy efficiency programs				(0.3)	(1.4)	(4.9)	(7.5)	(10.5)	(10.6)	(12.5)	(12.6)	(12.7)	(12.8)	(12.9)	(12.9)	(13.0)	(13.1)	(13.2)
PEAK NET OF ANTICIPATED ENERGY EFFICIENCY PROGRAMS				577.4	578.0	577.1	579.3	589.2	602.4	614.2	628.3	642.6	657.5	672.3	687.6	703.4	719.6	736.2
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	79.0
AEP Purchase	Duke Control Area	Coal	Base	26.0														
CP&L SOR A	Duke Control Area	Mix	Base	29.0														
SCE&G Intermediate Resouce	Duke Control Area	Gas	Intermediate	32.0	32.0	32.0												
AEP Baseload Resource	Duke Control Area	Mix	Base	19.0	19.0	19.0												
Dominion PPA	Duke Control Area	Mix	Intermediate	19.0	19.0	19.0	19.0	19.0										
Total NCEMC Existing Resources				204.0	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
SEPA	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	16.0
Morgan Stanley Purchases (3)																		
Total Morgan Stanley Purchases	Various	Mix	Base/Intermediate/Peaking	265.0														
Southern Power/Southern Company Purchases (4)																		
Total Southern Purchases	Various	Mix	Base/Intermediate/Peaking	92.4	413.0	412.1	465.3	475.2	507.4	519.2	533.3	547.6	562.5	577.3	592.6	608.4	624.6	641.2
TOTAL RESOURCES (MW)				577.4	578.0	577.1	579.3	589.2	602.4	614.2	628.3	642.6	657.5	672.3	687.6	703.4	719.6	736.2
RESERVE CAPACITY (MW) (4)			15% of Peak EU Load	86.7	86.9	87.3	88.0	90.0	92.0	94.0	96.1	98.3	100.5	102.8	105.1	107.5	109.9	112.4
REPS Resources																		
ANNUAL ENERGY BEFORE ENERGY EFFICIENCY PROGRAMS(GWH) (5)				2,506.1	2,527.5	2,551.9	2,591.9	2,645.7	2,701.0	2,757.9	2,816.3	2,876.3	2,937.4	2,999.5	3,063.3	3,128.9	3,196.2	3,265.4
Less: Impact of anticipated energy efficiency programs				(0.8)	(2.0)	(45.9)	(70.7)	(99.4)	(99.8)	(116.6)	(117.3)	(118.1)	(118.9)	(119.7)	(120.5)	(121.3)	(122.2)	(123.1)
NET ANNUAL ENERGY				2,505.2	2,525.5	2,506.0	2,521.2	2,546.3	2,601.2	2,641.2	2,698.9	2,758.2	2,818.5	2,879.8	2,942.8	3,007.5	3,074.0	3,142.3
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
Anticipated Solar Resources	TBD	Solar	N/A		0.3	0.3	1.0	1.0	1.0	1.0	2.0	2.0	3.0	3.0	3.0	3.0	3.0	3.0
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
Other Anticipated Renewable Resources (TBD)	TBD	TBD	TBD			4.5	4.7	4.9	5.0	13.4	13.7	14.1	31.9	33.0	34.1	35.2	36.3	38.0
Total Anticipated Renewable Capacity				19.0	19.3	23.8	24.7	24.9	25.0	33.4	34.7	35.1	53.9	55.0	56.1	57.2	58.3	60.0
Energy from renewable resources (GWH):	REC's Carried Forward																	
Iredell Transmission LLC	32			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
Anticipated Solar Resources				0.8	1.8	1.8	1.8	1.8	2.6	2.6	2.6	2.6	3.9	3.9	3.9	3.9	3.9	3.9
SEPA	21			21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Nextera Wind REC's(Out of State)	150																	
Salem Energy Systems LLC REC's	60			30.0														
Other Renewable Resources/REC's needed											53.6	239.0	243.8	250.0	256.4	263.0	269.7	276.6
Demand Side Management																		
	# Customers	Demand Reduction	Hours in DSM															
DEMAND SIDE MANAGEMENT PROGRAMS: Activated during Peak Hours																		
Residential Water Heaters	23,659	7.56	0	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
Coincident Peak Commercial/Industrial Consumers	30	8.83	42 hours	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
Residential Air Conditioners	26,470	8.65	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
Annual Peak Demand (6)																		
2008 Peak-Jan 25th, 2008 HE 8:00am –555 MW																		
2009 Peak-Jan 17th, 2009 HE 9:00am –607 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 term of the initial purchase with Morgan Stanley is 7 years beginning in 2004. All current and future resources provided by Morgan Stanley are firm; the Morgan Stanley purchase is a network resource recognized by Duke Transmission. Resources provided by Morgan to serve load in the Duke control area will come from resources in the Duke control area or through imports made with firm transmission at interties with Southern, AEP, and Yadkin. These firm transmission purchases have been designated in the application with the transmission provider.
4. 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 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
5. Energy values are measured at generation.
6. 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 (2009 Load Forecast)

Haywood EMC - Duke Control Area

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
PEAK (MW) (1)	24	25	25	26	26	26	27	27	27	28	28	28	29	29	30
ANNUAL ENERGY (GWh) (1)	126	128	130	131	133	135	137	138	140	142	144	145	147	149	151

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 2009 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

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Load Requirements:															
PEAK (MW) (1)	32	33	33	34	34	34	35	35	36	36	37	37	38	38	39
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	17	18	17	17	18	18	19	19	24	26	29	31	32
TOTAL RESOURCES (MW)	32	33	33	34	34	34	35	35	36	36	37	37	38	38	39
RESERVE CAPACITY (MW) (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL ENERGY (GWh) (1)	196	198	201	204	206	209	212	214	217	220	223	225	228	231	234

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

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
PEAK (MW) (1)	57	57	58	59	60	61	62	62	63	64	65	66	67	68	69
ANNUAL ENERGY (GWh) (1)	322	326	331	335	339	344	348	353	357	361	366	371	376	381	386
ANNUAL ENERGY (GWh) (1) (Including Impact of Energy Efficiency Programs)	320	322	325	327	329	331	333	336	341	345	350	354	359	364	369

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

Table 1.3: Haywood EMC Projected Winter Peak Loads, Resources and Annual Energy (2009 Load Forecast)

Haywood EMC - Duke Control Area

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
PEAK (MW) (1)	31	31	32	32	32	33	33	34	34	35	35	36	36	37	37
ANNUAL ENERGY (GWh) (1)	126	128	130	131	133	135	137	138	140	142	144	145	147	149	151

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 2009 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

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Load Requirements:															
PEAK (MW) (1)	49	50	51	51	52	53	53	54	55	55	56	57	58	59	59
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)	32	34	35	35	35	36	36	37	38	38	43	46	49	52	52
TOTAL RESOURCES (MW)	49	50	51	51	52	53	53	54	55	55	56	57	58	59	59
RESERVE CAPACITY (MW) (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL ENERGY (GWh) (1)	196	198	201	204	206	209	212	214	217	220	223	225	228	231	234

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

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
PEAK (MW) (1)	80	81	82	83	84	85	87	88	89	90	91	93	94	95	96
ANNUAL ENERGY (GWh) (1)	322	326	331	335	339	344	348	353	357	361	366	371	376	381	386
ANNUAL ENERGY (GWh) (1) (Including Impact of Energy Efficiency Programs)	320	322	325	327	329	331	333	336	341	345	350	354	359	364	369

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

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 968

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:		
Application of Progress Energy Carolinas, Inc.	)	
for a Certificate of Public Convenience and	)	ORDER ISSUING CERTIFICATE
Necessity to Construct Approximately 620 MW	)	OF PUBLIC CONVENIENCE AND
of Combined Cycle Generating Capacity at its	)	NECESSITY
New Hanover County Facility near Wilmington,	)	
North Carolina	)	

HEARD: Judicial Building, Courtroom 300, 314 Princess Street, Wilmington, North Carolina, on Tuesday, February 23, 2010, at 7:00 p.m., and

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Wednesday, March 31, 2010, at 9:00 a.m.

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

APPEARANCES:

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

Len S. Anthony, General Counsel - Progress Energy Carolinas, Inc. and Kendal C. Bowman, Associate General Counsel, Post Office Box 1551, Raleigh, North Carolina 27602-1551

For the Using and Consuming Public:

Dianna Downey, 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: Commission Rule R8-61(a) requires a utility seeking a certificate of public convenience and necessity to construct a generating facility with a capacity of 300 megawatts (MW) or more to file with the Commission certain information

120 days prior to filing the application for the certificate. Commission Rule R8-61(b)(4) requires updates to the information to be filed with the application. On December 4, 2009, Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC), filed a motion for waiver of Commission Rule R8-61(a) and (b)(4) with regard to PEC's proposed application for a certificate of public convenience and necessity to construct a generating facility to replace PEC's three coal-fired generating units at its Sutton Plant in New Hanover County. In support of its motion, PEC stated that the proposed facility will be constructed at an existing generation site and that PEC needs to begin construction soon given the current low cost for equipment and services. PEC also stated that both the Public Staff – North Carolina Utilities Commission (Public Staff) and the North Carolina Attorney General had agreed that the prefiling was not necessary under the circumstances. On December 15, 2009, the Commission issued its Order Granting Waiver of Prefiling Requirement.

On December 18, 2009, PEC filed an Application for a Certificate of Public Convenience and Necessity (Application) pursuant to G.S. 62-110.1 and Commission Rule R8-61, along with the supporting testimony of Glen A. Snider, Manager – Resource Planning. PEC proposes to construct approximately 620 MW of combined-cycle (CC) natural gas-fired generating capacity at its existing Sutton Plant generation site in New Hanover County near Wilmington, North Carolina. The planned in-service date of the facility is December 2013.

On December 30, 2009, Attorney General Roy Cooper gave Notice of Intervention in this docket on behalf of the using and consuming public pursuant to G.S. 62-20. Intervention and participation by the Public Staff is made and recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On January 5, 2010, the Commission issued its Order Scheduling Hearings, Establishing Procedural Deadlines and Requiring Public Notice. Pursuant to this Order, a public hearing for the purpose of taking public witness testimony was scheduled on February 23, 2010, in Wilmington and an evidentiary hearing was scheduled on March 31, 2010, in Raleigh. The Commission also required PEC to give public notice of the application and hearings, and PEC properly published notice.

The public hearing in Wilmington was held on February 23, 2010, as scheduled. No public witnesses testified at the public hearing.

On March 16, 2010, the Public Staff filed the affidavits of Kennie D. Ellis, Engineer – Electric Division, and Darlene P. Peedin, Supervisor, Electric Section – Accounting Division, together with a notice that the affidavits would be used in evidence at the hearing pursuant to G.S. 62-68.

On March 25, 2010, PEC filed a motion to excuse its witness Glen A. Snider from appearing at the March 31, 2010 evidentiary hearing and to allow the introduction of all prefiled direct testimony, exhibits, and affidavits into the record. PEC stated that all parties had agreed to waive cross-examination of witness Snider and the Public Staff's witnesses. This motion was allowed by Commission Order issued March 26, 2010.

On March 31, 2010, the hearing was held in Raleigh as scheduled. No public witnesses appeared to testify at the hearing. The prefiled direct testimony and exhibits of PEC witness Glen A. Snider were received into evidence as if given orally. The affidavits of Public Staff witnesses Kennie D. Ellis and Darlene P. Peedin together with the respective appendices, were also received into evidence as if given orally. The hearing was then concluded.

On May 11, 2010, PEC filed a proposed order, and on May 12, 2010, the Public Staff filed a letter stating that it supported adoption of PEC's proposed order.

Based upon consideration of all the evidence admitted during the hearings and the entire record of this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. PEC is a North Carolina corporation engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North and South Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. PEC is lawfully before this Commission based upon its application filed pursuant to G.S. 62-110.1 and Commission Rule R8-61.

2. PEC owns and operates three coal-fired electric generating units with a combined generating capacity of approximately 600 MW at its Sutton Plant site in New Hanover County. None of the Sutton coal-fired units have any form of flue gas desulfurization to limit their emissions of sulfur dioxide (SO_2) and mercury. None of the units have any environmental controls to limit their emissions of greenhouse gases (GHG).

3. If PEC continues to operate the Sutton coal-fired units, state and federal laws and regulations will require PEC to make significant investments to install nitrogen oxide (NO_x), SO_2, and mercury emissions controls.

4. If PEC continues to operate the Sutton coal-fired units, it is possible that new federal regulations or legislation will require PEC to reduce its emissions of GHG.

5. If PEC continues to operate the Sutton coal-fired units, it will have to construct a new ash pond, convert to dry ash storage, or arrange for offsite storage in order to dispose of coal combustion products (CCP) generated by the operation of the units.

6. PEC seeks a certificate of public convenience and necessity to construct approximately 620 MW of CC natural gas-fired generating capacity at the Sutton Plant site. The proposed facility will consist of two combustion turbines and two heat recovery

steam generators to produce steam to drive a single steam turbine. The facility will be equipped with duct firing capability which will increase its generating capacity to approximately 620 MW during peak conditions.

7. It is more cost effective for PEC to retire its existing Sutton coal-fired units and replace them with the proposed CC generating facility than to install the environmental controls and incur the handling, disposal, and storage costs necessary to allow their continued operation.

8. Since PEC plans to cease operation of the coal-fired units at the Sutton Plant site upon completion of the proposed CC generating facility of essentially the same capacity at the same site, PEC is not requesting approval to construct any net additional generating capacity in this proceeding.

9. The proposed CC generating facility is the appropriate substitution for the coal-fired units, as opposed to alternative types of generation.

10. Generation is critical in the general location of the Sutton Plant site for voltage support to both the Brunswick Nuclear Plant and the eastern part of the PEC system. The existing site has the necessary infrastructure to support the proposed CC generating facility, and minimal investment would be required to connect to PEC's transmission system.

11. Due to the uniqueness of the present circumstances and the criticality of generation at the Sutton location, PEC has proceeded appropriately in its pursuit of self-built generation at the Sutton plant site.

12. The process being implemented to plan and construct the proposed CC generating facility and PEC's construction cost estimate are reasonable and should be approved.

13. It is reasonable and appropriate to issue a certificate of public convenience and necessity for the construction of the proposed CC generating facility at the Sutton Plant site, subject to the following conditions recommended by the Public Staff:

a. That the facility certificated in this order shall be constructed and operated in strict accordance with all applicable laws and regulations, including the provisions of all permits issued by the North Carolina Department of Environment and Natural Resources;

b. That PEC shall file with the Commission in this docket a progress report and any revisions in the cost estimate for this facility on an annual basis, with the first report due no later than one year from the date of this order;

c. That, immediately upon completion of the construction of and placement into service of the CC facility, PEC shall permanently cease operation of the three coal-fired generating units at its Sutton Plant facility and shall file with the Commission in this docket a notice that operation of all of the coal-fired generation at the Sutton Plant has ceased;

d. That issuance of this order does not constitute approval of the final costs associated with the construction of the CC generation at the Sutton Plant site for ratemaking purposes, and this order is without prejudice to the right of any party to take issue with the ratemaking treatment of the final costs in a future proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding is essentially informational, procedural, and jurisdictional in nature and is not controversial.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2-5

The evidence supporting these findings of fact is contained in PEC's Application and in the testimony of PEC witness Snider.

The evidence shows that PEC operates three coal-fired units with a total generating capacity of approximately 600 MW at its Sutton Plant site in New Hanover County. PEC faces many environmental compliance challenges in connection with the Sutton units. These challenges include the following: none of the Sutton coal units have any flue-gas desulfurization equipment to limit their emissions of SO_2 and mercury, and the existing ash pond at the Sutton Plant site will reach full capacity on or before 2014.

PEC states that in 2006, North Carolina adopted mercury emission regulations (N.C. Mercury Rules). The N.C. Mercury Rules establish mercury limits, allocate emission allowances, and require all coal-fired units to have mercury-control technology installed no later than December 31, 2017. The N.C. Mercury Rules require PEC to develop an emission control plan for each operating unit by January 1, 2013, that will identify a schedule for installation and operation of mercury controls. In addition, the United States Environmental Protection Agency (EPA) is currently developing Maximum Achievable Control Technology standards for mercury and other hazardous air pollutants emitted by steam generators.

PEC states that both the North Carolina Clean Smokestacks Act and the federal Clean Air Interstate Rule (CAIR) require reductions in SO_2 emissions. The Clean Smokestacks Act requires PEC to reduce its annual North Carolina emissions of SO_2 from its coal-fired plants to 50,000 tons or fewer by January 1, 2013. PEC plans to achieve this required reduction by retiring the Lee coal-fired units. In addition, North Carolina has adopted rules implementing the federal CAIR (N.C. CAIR). N.C. CAIR incorporated the CAIR allowance trading system under which an entity could either reduce its emissions to the required limit, purchase sufficient allowances to comply with the rule's requirements, or undertake a combination of both. In 2008, the Court of Appeals for the District of Columbia Circuit at first vacated federal CAIR and then, in December 2008, modified its earlier opinion to remand the case to EPA without vacatur for further proceedings. In the interim, CAIR and N.C. CAIR remain in effect while EPA develops a revised rule. PEC anticipates that the revised CAIR will require additional reductions of SO_2 and NO_x and will require point-specific controls, rather than allowance trading.

PEC also states that on December 7, 2009, EPA issued a final "endangerment finding," declaring that carbon dioxide (CO_2) and five other GHG emissions are pollutants that threaten public health and welfare. This finding gives EPA the authority to regulate CO_2 under the Clean Air Act. Concurrently, Congress is considering legislation to regulate GHG. The American Clean Energy and Security Act of 2009, also known as the Waxman-Markey bill, was approved by the House of Representatives on June 26, 2009, and in the Senate, the Clean Energy Jobs and American Power Act, also known as the Kerry-Boxer bill, has been introduced and approved by a key committee. Even in the absence of Congressional action, the EPA regulatory efforts are expected to continue. The EPA's endangerment finding provides a basis for regulating CO_2 and raises the possibility of new requirements being imposed in future and current air emission permits. Additionally, PEC cites two recent federal appellate court decisions which suggest that regulation of GHG may occur through legal actions based upon state law claims for nuisance, trespass, or negligence.

Finally, PEC states that EPA is currently considering re-characterizing the nature and regulation of CCP (coal combustion products such as bottom ash, fly ash, and related materials) in response to the ash pond impoundment failure at TVA's Kingston Plant. If EPA increases the regulatory requirements applicable to CCP, the handling, storage, and disposal of CCP may result in significantly increased costs. The phase-out of surface impoundments is also under consideration by EPA. Since the current ash pond at PEC's Sutton Plant site will reach full capacity on or before 2014, PEC must incur significant costs to construct a new ash pond or convert to dry ash handling together with onsite disposal or transportation for offsite disposal, even if EPA does not increase regulatory requirements for CCP.

None of the parties to this proceeding disputed PEC's description of the environmental compliance challenges associated with the future operation of coal-fired generation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 6-13

The evidence supporting these findings of fact is found in PEC's Application and in the testimony of PEC witness Snider and the affidavits of Public Staff witnesses Ellis and Peedin.

Given the environmental compliance challenges associated with coal-fired generation, PEC evaluated the cost effectiveness of continuing to operate the Sutton coal-fired units. PEC concluded that simply retiring these coal units is not an option due to voltage support requirements in this area of PEC's system. PEC witness Snider testified that voltage support requirements in the eastern region and the needs of the Brunswick Nuclear Plant require PEC to have approximately 600 MW of generating capacity at a location that is essentially the same as the Sutton Plant site.

Regarding the type of generation that should be considered to replace the Sutton coal units, PEC witness Snider relied upon the information in PEC's 2008 Integrated Resource Plan and 2009 update. According to witness Snider, these documents demonstrate that gas-fired generators are the most environmentally benign and economical large-scale capacity additions available for meeting peak and intermediate loads. New designs of these technologies are more efficient (as measured by heat rate) than previous designs, resulting in a smaller impact on the environment. The advancements associated with CC generation provide greater operational flexibility relative to combustion turbines without heat recovery steam generators and steam turbines. This is due to several factors. First, each combustion turbine can be operated in a simple-cycle mode or in concert with its heat recovery steam generator and the steam turbine to enhance reliability and optimize unit operations. Second, the proposed CC facility has approximately 70 MW of duct firing capability that can be dispatched during peak demand periods, much as a peaker would be dispatched, but at a fraction of the cost of installing an additional combustion turbine. Third, a CC generating facility can be economically utilized across a wide capacity range, approximately 30% to 60%, which means that it can grow with system energy needs, unlike oil-fired combustion turbines, which are logistically and environmentally hindered from operating at capacity factors greater than roughly 5% to 10%. Witness Snider also noted that CC technology has an additional benefit within PEC's balanced solution of providing fuel diversity and lowering long-term fuel price volatility.

Witness Snider further testified that a CC facility fueled by natural gas is the cleanest and most efficient fossil-fueled generation currently available. There are virtually no SO_2 emissions, NO_x emissions are approximately 80% less than new coal-fired generation, and CO_2 emissions are approximately 60% less than new coal-fired generation.

PEC compared the cost of building a new approximately 620-MW CC natural gas-fired generator at the Sutton Plant site to the cost of continuing to operate the three existing coal-fired units, including the cost of modifications that could be required by new environmental regulations. According to PEC, continued operation of the coal units will require new SO_2, NO_x, and mercury emission controls as early as 2015. Continued operation will also require a new permitted landfill for ash and other CCP. Retiring these coal units will eliminate the need for these controls and the new landfill, saving almost $720 million in capital expenditures. Retiring the coal units will also avoid ongoing operations and maintenance (O&M) costs and capital expenditures for the units, estimated at over $670 million in O&M and over $285 million in capital through the

2009-2039 study period. These cost savings are partially offset, however, by O&M and capital expenditures for the proposed CC facility.

PEC described the economic analysis of the proposed CC facility, performed in terms of cumulative present value of revenue requirements (CPVRR). The costs associated with the continued operation of the coal units were: the ongoing O&M costs; the capital costs to operate and maintain the units; the cost of adding emission controls to the units; a new ash landfill for the plant; and the cost of CO_2 emissions, i.e., the difference in CO_2 emissions between the case with the proposed CC facility and the case with the coal units' continued operation. For the proposed CC facility, the cost components were: the ongoing O&M and capital costs of the coal units until they are retired at the end of 2013; the O&M and capital costs of the proposed CC facility; the natural gas pipeline reservation costs; and the change in total system fuel and purchased power costs from continued coal operation. Among the costs included in the CPVRR of continued coal operations were $795 million of costs associated with SO_2 and NOx environmental controls. PEC evaluated the likelihood of being required to install these controls and concluded that new regulation and management of emissions and CCP was highly probable and that inclusion of these costs in the analysis was appropriate. PEC stated that three of the key uncertainties in retiring and replacing the coal units are the cost of natural gas, the cost of coal, and the cost of CO_2 emissions. PEC stated that construction of a new landfill for ash disposal would require a county "special use" permit. If a landfill for ash cannot be built at the Sutton Plant site, the CCP would have to be transported to another location at an assumed cost of $55/ton. This would increase the cost of continuing to operate the coal units by over $440 million through the 2009-2039 study period.

According to PEC, the total savings associated with retiring the coal units and replacing them with the proposed CC facility is approximately $90 million. If transporting the CCP is required, the savings would be more than $192 million. PEC concluded that, given the range of variables and the evaluation of uncertainties, building the proposed CC facility at the Sutton Plant site is the most cost effective and robust decision.

Witness Snider also described the process being proposed by PEC to plan and construct the CC facility. He testified that since 1997, PEC has placed in-service approximately 2,230 MW of new combustion turbines and 480 MW of CC generating capacity. PEC has extensive experience in both negotiating the purchase of these facilities and installing and constructing them. The proposed CC facility would be the result of a competitive bidding process. PEC would invite proposals from different equipment vendors for the purchases of the combustion turbine generators and other items of major equipment. PEC would also request bids from available and qualified engineering and construction firms to construct the facility.

Public Staff witness Ellis stated in his affidavit that the Public Staff investigated and determined that generation in the general location of the Sutton Plant site is critical for voltage support to both the Brunswick Nuclear Plant and the eastern part of the PEC system. Therefore, if PEC retires the Sutton coal units, it must replace them with some other form of generation near the same location. Witness Ellis noted that, because PEC is not requesting approval to construct net additional generating capacity in this proceeding, it is unnecessary for the Commission to consider whether PEC's proposal is consistent with the analysis of long-range needs for expansion of facilities for generation of electricity required by G.S. 62-110.1(c). Witness Ellis stated that, while mindful of the Commission's expectation expressed in Docket No. E-100, Sub 122, that in future CPCN proceedings electric utilities should "provide evidence of a robust and thoughtful review of opportunities in the wholesale market" and "employ the use of competitive bidding and/or third-party evaluators as necessary and appropriate," the Public Staff believes that PEC proceeded appropriately in its pursuit of self-built generation given the uniqueness of the present circumstances and the criticality of having generation at the Sutton Plant site.

Public Staff witness Ellis did not identify any major concerns regarding the process being proposed by PEC to plan and construct the CC units. He stated that PEC has the experience to manage the construction of the CC units, thus avoiding the incremental costs associated with a third party provider. He noted that PEC is competitively bidding all large equipment and engineering, procurement, and construction services and would take advantage of economies of scale by soliciting bids for equipment and services to both the Wayne County facility and the proposed Sutton CC facility at the same time.

Public Staff witness Peedin agreed that the results of PEC's base case economic analysis shows that there is a benefit in retiring the Sutton coal units and replacing them with the proposed CC natural gas-fired facility. She also stated that PEC's analysis, in comparing the cost of continuing to operate the coal units with constructing and operating the proposed CC facility, used reasonable methodologies and assumptions consistent with previous evaluations of generation additions found to be acceptable by the Commission, and that the analysis was conducted in a satisfactory manner. Additionally, she stated that it appears that, based on PEC's assumptions, the estimated cost of the proposed CC facility is comparable on a per-kW basis to other recent additions of CC facilities in the State and that PEC's proposal and cost estimate to build the proposed CC facility are reasonable and should be approved.

Only PEC and the Public Staff presented evidence in this proceeding. The evidence supports the retirement of the existing Sutton coal units and replacing them with the proposed 620-MW natural gas-fired CC electric generating facility. The granting of a certificate for the new facility requires Commission approval of the cost estimate for the construction being proposed and a finding that the construction is consistent with the Commission's plan for expansion of electric generating capacity. Public Staff witness Ellis concluded that, because PEC is not requesting approval of any net additional generating capacity, it is unnecessary to consider whether PEC's proposal is consistent with the analysis of long-range needs for expansion of facilities for generation of electricity required by G.S. 62-110.1(c). The Commission finds and concludes that, because PEC is proposing to retire existing generation and replace it with essentially the same amount of new generation at the same site and, thus, is essentially requesting no net additional generating capacity, PEC's proposal is consistent with long-range needs for expansion of electric generating facilities in the State. Public Staff witness Peedin concluded that PEC's cost estimate to build the proposed CC facility is reasonable and should be approved. The Commission so finds, but notes that its approval is made only in the context of this proceeding and does not apply to any ratemaking determination or proceeding. The Commission notes that PEC is required by G.S. 62-110.1(f) to provide an annual progress report and any revisions to its cost estimate, and the Commission so requires.

The Commission finds that PEC's Application for a Certificate of Public Convenience and Necessity to construct a 620-MW CC natural gas-fired electric generating facility at the Sutton Plant site in New Hanover County should be granted, subject to the following conditions recommended by the Public Staff, which the Commission finds to be appropriate:

1. That the facility certificated in this order shall be constructed and operated in strict accordance with all applicable laws and regulations, including the provisions of all permits issued by the North Carolina Department of Environment and Natural Resources;

2. That PEC shall file with the Commission in this docket a progress report and any revisions in the cost estimate for this facility on an annual basis, with the first report due no later than one year from the date of this order;

3. That immediately upon completion of the construction and placement into service of the CC facility, PEC shall permanently cease operation of the three coal-fired generating units at its Sutton Plant facility and shall file with the Commission in this docket a notice that operation of all of the coal-fired generation at the Sutton Plant has ceased;

4. That issuance of this order does not constitute approval of the final costs associated with the construction of the CC generation at the Sutton Plant site for ratemaking purposes, and this order is without prejudice to the right of any party to take issue with the ratemaking treatment of the final costs in a future proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That a certificate of public convenience and necessity should be, and hereby is, granted to PEC to construct a 620-MW CC natural gas-fired electric generating facility to be located at the Sutton Plant site in New Hanover County subject to the above conditions and the following ordering paragraphs, and this order shall constitute the certificate;

2. That the facility certificated herein shall be constructed and operated in strict accordance with all applicable laws and regulations, including the provisions of all

permits issued by the North Carolina Department of Environment and Natural Resources;

3. That PEC shall file with the Commission in this docket a progress report and any revisions in the cost estimate for this facility on an annual basis, with the first report due no later than one year from the date of this order;

4. That PEC shall permanently cease operation of the three coal-fired units at its Sutton Plant site immediately upon completion of construction and placement into service of the CC facility certificated herein and shall file with the Commission a notice that operation of all coal-fired generation at the Sutton Plant site has ceased; and

5. That issuance of this Order does not constitute approval of the final costs associated with the construction of the CC facility at the Sutton Plant site for ratemaking purposes, and this Order is without prejudice to the right of any party to take issue with the ratemaking treatment of the final costs in a future proceeding.

ISSUED BY ORDER OF THE COMMISSION.

This the 9th day of June, 2010.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount

Gail L. Mount, Deputy Clerk

Sk060710.01

North Carolina Electric IOU Service Area Map