E-100, Sub 128

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

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

DATE DUE: DECEMBER 31, 2011
SUBMITTED: NOVEMBER 30, 2011

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

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SUBMITTED BY THE NORTH CAROLINA UTILITIES COMMISSION

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Western Carolina University

North Carolina Electric Membership Corporation

ElectriCities of North Carolina

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LIST OF ACRONYMS

AP Advanced Passive
APWR Advanced Pressurized-Water Reactor
ARRA 2009 American Recovery and Reinvestment Act of 2009
Blue Ridge Blue Ridge EMC
CC combined-cycle
CFB circulating fluidized bed
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
ESP Early Site Permit
FERC Federal Energy Regulatory Commission
GreenCo GreenCo Solutions, Inc.
GridSouth GridSouth Transco, LLC
G.S. General Statute
GWh gigawatt-hour/s
Halifax Halifax EMC
Haywood Haywood EMC
IOU investor-owned electric utility
IRP *integrated resource planning/integrated resource plans*
kWh kilowatt-hour/s
MW megawatt/s
MWh megawatt-hour/s
NARUC National Association of Regulatory Utility Commissioners
NC Power Dominion North Carolina Power
NC-RETS North Carolina Renewable Energy Tracking System
NCEMC North Carolina Electric Membership Corporation
NCEMPA North Carolina Eastern Municipal Power Agency

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
Santee Cooper Public Service Authority of South Carolina
SCC State Corporation Commission of Virginia
SCE&G South Carolina Electric & Gas
Senate Bill 3 Session Law 2007-397
SEPA Southeastern Power Administration
SERC Southeastern Electric Reliability Corporation
TOU time-of-use
TVA Tennessee Valley Authority
VACAR Virginia and Carolinas Regional Reliability Council
VEPCO Virginia Electric and Power Company
VCHEC Virginia City Hybrid Energy Center
WPSA Wholesale Power Supply Agreement

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APPENDICES

1. EXECUTIVE SUMMARY

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

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

Duke and Progress, the two largest electric IOUs in North Carolina, together supply about 96% of the utility-generated electricity consumed in the state. Approximately 18% of the IOUs' 2010 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)	
	2010	2009	2010	2009	2010	2009
Progress	39,075	36,694	16,817	13,471	59,702	56,947
Duke	57,843	54,348	5,032	4,902	85,443	79,830
NC Power	4,330	4,029	868	707	84,605	81,513

*GWh = 1 Million kWh (kilowatthours)

During the 2011 to 2025 timeframe, the average annual growth rate in summer peak demand for electricity in North Carolina is forecasted to be approximately 1.6%. Table ES-2 illustrates the systemwide average annual growth rates forecast by the IOUs that operate in North Carolina. Each uses generally accepted forecasting methods and, although their forecasting models are different, the econometric techniques employed by each are widely used for projecting future trends. Under normal weather patterns, summer peak demand remains higher than winter peak demand for all three IOUs.

Table ES-2: Forecast Annual Growth Rates for Progress, Duke, and NC Power (After Energy Efficiency and Demand-Side Management are Included) (2011 – 2025)

	Summer Peak	Winter Peak	Energy Sales
Progress	1.6%	1.8%	1.2%
Duke	1.6%	1.6%	1.8%
NC Power	1.7%	1.8%	1.8%

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 2010

	Progress	Duke	NC Power
Coal	49%	44%	31%
Nuclear	35%	48%	28%
Net Hydroelectric*	1%	1%	0%
Oil and Natural Gas	9%	1%	11%
Wood/Biomass	0%	0%	1%
Purchased Power	6%	6%	29%

* 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 November 30, 2010 Annual Report. It is based primarily on reports to the Commission by the regulated electric utilities serving North Carolina, but also includes information from other records and Commission files. Much of the material was gathered in Docket No. E-100, Sub 128, Investigation of Integrated Resource Planning in North Carolina - 2010.

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, 2010, Duke had 1,847,000 customers located in North Carolina, and Progress had 1,272,000. 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 18% 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 2010 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)	
	2010	2009	2010	2009	2010	2009
Progress	39,075	36,694	16,817	13,471	59,702	56,947
Duke	57,843	54,348	5,032	4,902	85,443	79,830
NC Power	4,330	4,029	868	707	84,605	81,513

*GWh = 1 Million kWh (kilowatthours)

The Commission does not regulate the retail rates of municipally-owned electric systems or electric membership corporations. However, the Commission does have jurisdiction over the licensing of all new electric generating plants and large scale transmission facilities built in North Carolina. Commission Rule R8-60(b) specifies that the IRP process is applicable to the North Carolina Electric Membership Corporation (NCEMC), and any individual electric membership corporation (EMC) to the extent that it is responsible for procurement of any or all of its individual power supply resources.

EMCs are independent, non-profit corporations. There are 31 EMCs serving 1,019,000 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 1.8% per year during the 2011-2025 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. NCEMC also owns 620 MW of combustion turbine (CT) 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 CT generator at its existing Richmond County site. NCEMC expects to achieve commercial operation of this CT in May, 2013. This addition will result in a total facility output of 339 MW. Also, 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.

On December 17, 2007, Blue Ridge EMC entered into a Full Requirements Power Purchase Agreement with Duke. As a result, the Blue Ridge electric load is now included in Duke's IRP. Load data for the other Independent Members is shown in Appendices 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 goal is to serve all its members as a single integrated system.

NCEMC currently purchases wholesale electricity from Progress, Duke, Dominion, American Electric Power, South Carolina Electric & Gas (SCE&G), 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 from January 1, 2013 through December 31, 2032. Under this agreement, NCEMC owns and maintains the Anson facility for the exclusive use of meeting the joint needs of NCEMC and Progress. Progress will purchase, schedule, and deliver natural gas and fuel oil in order to meet these dispatch requirements. In addition, NCEMC and Southern Power have executed a baseload sale agreement. Under this agreement NCEMC will sell 100 MW 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 require Commission approval.

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

One agency, the North Carolina Eastern Municipal Power Agency (NCEMPA), is the wholesale supplier to 32 cities and towns in eastern North Carolina. NCEMPA owns portions of five Progress generating units (about 700 MW of coal and nuclear capacity). NCEMPA also has Supplemental Load Agreements with Progress that run through 2017. These contracts provide for additional power when load requirements exceed the capacity NCEMPA owns.

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

NCMPA1 purchases power through bilateral agreements with other generators to obtain its requirements above its Catawba entitlement. To meet its supplemental power requirements, NCMPA1 has purchase power agreements with Duke, Southern Power, Georgia Power, and SEPA. NCMPA1 also owns 65 MW of diesel-fueled distributed generation located at certain city delivery points, and has contracts for an additional 84 MW of generation owned by municipalities and retail customers which is available during times of high demand and spiking wholesale prices. During 2010, NCMPA1 brought online 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 32,700 households and 8,500 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 seven substations and switchyards and nearly 119 miles of transmission line in North Carolina.

4. THE HISTORY OF INTEGRATED RESOURCE PLANNING IN NORTH CAROLINA

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

Initial IRP Rules

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

The initial IRPs were filed with the Commission in April 1989. In May of 1990, the Commission issued an Order in which it found that the initial IRPs of Progress, Duke, and NC Power were reasonable for purposes of that proceeding and that NCEMC should be required to participate in all future IRP proceedings. By an Order issued in December 1992, Rule R8-62 was added. It covers the construction of electric transmission lines.

The Commission subsequently conducted a second and third full analysis and investigation of utility IRP matters, resulting in the issuance of Orders Adopting Least Cost Integrated Resource Plans on June 29, 1993, and February 20, 1996. A subsequent round of comments included general endorsement of a proposal that the two/three year IRP filing cycle, plus annual updates and short-term action plans, be replaced by a single annual filing. There was also general support for a shorter planning horizon than the fifteen years required at that time.

Streamlined IRP Rules (1998)

In April 1998, the Commission issued an Order in which it repealed Rules R8-56 through R8-59 and revised Rules R8-60 through R8-62. The new rules shortened the reported planning horizon from 15 to 10 years and streamlined the IRP review process while retaining the requirement that each utility file an annual plan in sufficient detail to allow the Commission to continue to meet its statutory responsibilities under G.S. 62-110.1(c) and G.S. 62-2(a)(3a).

These revised rules allowed the Public Staff and any other intervenor to file a report, evaluation, or comments concerning any utility's annual report within 90 days after the utility filing. The new rules further allowed for the filing of reply comments 14 days after any initial comments had been filed and required that one or more public hearings be held. An evidentiary hearing to address issues raised by the Public Staff or other intervenors could be scheduled at the discretion of the Commission.

In September 1998, the first IRP filings were made under the revised rules. The Commission concluded, as a part of its Order ruling on these filings, that the reserve margins forecast by Progress, Duke, and NC Power indicated a much greater reliance upon off-system purchases and interconnections with neighboring systems to meet unforeseen contingencies than had been the case in the past. The Commission stated that it would closely monitor this issue in future IRP reviews.

In June 2000, the Commission stated in response to the IOUs' 1999 IRP filings that it did not believe that it was appropriate to mandate the use of any particular reserve margin for any jurisdictional electric utility at that time. The Commission concluded that it would be more prudent to monitor the situation closely, to allow all parties the opportunity to address this issue in future filings with the Commission, and to consider this matter further in subsequent integrated resource planning proceedings. The Commission did, however, want the record to clearly indicate its belief that providing adequate service is a fundamental obligation imposed upon all jurisdictional electric utilities, that it would be actively monitoring the adequacy of existing electric utility reserve margins, and that it would take appropriate action in the event that any reliability problems developed.

Further orders required that IRP filings include a discussion of the adequacy of the respective utility's transmission system and information concerning levelized costs for various conventional, demonstrated, and emerging generation technologies.

Order Revising Integrated Resource Planning Rules – July 11, 2007

A Commission Order issued on October 19, 2006, in Docket No. E-100, Sub 111, opened a rulemaking proceeding to consider revisions to the IRP process as provided for in Commission Rule R8-60. On May 24, 2007, the Public Staff filed a Motion for Adoption of Proposed Revised Integrated Resource Planning Rules setting forth a proposed Rule R8-60 as agreed to by the various parties in that docket. The Public Staff asserted that the proposed rule addressed many of the concerns about the IRP process that were raised in the 2005 IRP proceeding and balanced the interests of the utilities, the environmental intervenors, the industrial intervenors, and the ratepayers. Without detailing all of the changes recommended in its filing, the Public Staff noted that the proposed rule expressly required the utilities to assess on an ongoing basis both the potential benefits of reasonably available supply-side energy resource options, as well as programs to promote demand-side management. The proposed rule also substantially increased both the level of detail and the amount of information required from the utilities regarding those assessments. Additionally, the proposed rule extended the planning horizon from 10 to 15 years, so the need for additional generation would be identified sooner. The information required by the proposed rule would also indicate the projected effects of demand response and energy efficiency programs and activities on forecasted annual energy and peak loads for the 15-year period. The Public Staff also noted that the proposed rule provided for a biennial, as opposed to annual or triennial, filing of IRP reports with an annual update of forecasts, revisions, and amendments to the biennial report. The Public Staff further noted that adoption of the proposed Rule R8-60 would necessitate revisions to Rule R8-61(b) to reflect the change in the frequency of the filing of the IRP reports.

With the addition of certain other provisions and understandings, the Commission ordered that revised Rules R8-60 and R8-61(b), attached to its Order as Appendix A, should become effective as of the date of its Order, which was entered on July 11, 2007. However, since the utilities might not have been able to comply with the new requirements set out in revised Rule R8-60 in their 2007 IRP filings, revised Rule R8-60 was ordered to be applied for the first time to the 2008 IRP proceedings in Docket No. E-100, Sub 118. These new rules were further refined in Docket No. E-100, Sub 113 to address the implementation of Senate Bill 3 requirements.

2010 Biennial IRP Proceeding (Docket No. E-100, Sub 128)

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

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

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

Comments, reply comments, briefs, and proposed orders were submitted as part of the proceeding. A public hearing was held on January 24, 2011. The Commission's Order Approving 2010 Biennial Integrated Resource Plans and 2010 REPS Compliance Plans, issued October 26, 2011, which includes the procedural history, can be found in the back of this report as Appendix 1.

5. LOAD FORECASTS AND PEAK DEMAND

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

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

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

Table 2: Forecast Annual Growth Rates for Progress, Duke, and NC Power (After Energy Efficiency and Demand-Side Management are Included) (2011 – 2025)

	Summer Peak	Winter Peak	Energy Sales
Progress	1.6%	1.8%	1.2%
Duke	1.6%	1.6%	1.8%
NC Power	1.7%	1.8%	1.8%

North Carolina utility forecasts of future peak demand growth rates are somewhat higher than forecasts for the nation as a whole. The 2010-2019 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 1.3%. This number is lower than that shown in NERC's prior year report of 1.5% to 1.6%.

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 2006 (in MW)

	Progress		Duke		NC Power	
	Summer	Winter*	Summer	Winter*	Summer	Winter*
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
2010	12,074	12,230	17,358	17,570	16,783	15,017

**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, CTs and other peaking plants usually operate less than 1,000 hours per year.

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

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

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

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

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

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

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

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

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

Table 4: Installed Utility-Owned Generating Capacity by Fuel Type (Summer Ratings) for 2010

	Progress	Duke	NC Power
Coal	41%	37%	28%
Nuclear	28%	33%	20%
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 2010, is provided in Table 5.

Table 5: Total Energy Resources by Fuel Type for 2010

	Progress	Duke	NC Power
Coal	49%	44%	31%
Nuclear	35%	48%	28%
Net Hydroelectric*	1%	1%	0%
Oil and Natural Gas	9%	1%	11%
Wood/Biomass	0%	0%	1%
Purchased Power	6%	6%	29%

* 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 CT 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 CTs 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 2011, Progress had 13,196 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 2011 resource plan proposes to add 4,491 MW of new capacity during the 2012-2026 period. This includes 920 MW of combined-cycle (CC) natural gas generation at the Company's Wayne County facility scheduled to go into service in January, 2013, and 625 MW of CC generation at the Sutton Plant with an expected in-service date of December, 2013. A nuclear baseload addition of 550 MW, through a regional partnership, continues to be shown in the 2020/2021 timeframe. In addition, approximately 100 MW of planned uprates to existing facilities are projected by 2017.

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 Fall 2011 and late 2013. These units total approximately 1,500 MW. The exact dates of these retirements may change subject to a number of variables.

The 2011 resource plan continues to contemplate the potential for regional partnerships rather than full ownership of a nuclear facility. For long range planning purposes, Progress assumed that 25% shares of undesignated nuclear would be available in the marketplace. This generation could come from partnerships in self-build nuclear facilities or from a partnership in another utility's regional nuclear project. Under this regional assumption, nuclear projects would be jointly undertaken by utilities in the region with participating utilities and load serving organizations taking ownership stakes in each others' projects. At this point in time, no specific plans for such partnerships have been entered into and the 25% nuclear blocks simply represent undesignated baseload generation for planning purposes.

Progress had previously announced that it was pursuing development of a combined construction and operating license (COL) application to potentially construct new nuclear facilities. That announcement was not a commitment to build a nuclear unit, but a necessary step to keep open the option of building such a unit or units. In January 2006, Progress announced that it had selected a site at the existing Harris Plant to evaluate for possible future nuclear expansion. It selected the Westinghouse Advanced Passive (AP) 1000 reactor design as the technology upon which to base its application. In February 2008, Progress submitted its COL application to the NRC for the construction of two additional reactors at the Harris site. If Progress receives COL approval from the NRC in 2014 and applicable state agency approvals, and if the decisions to build are made, Progress stated that a new plant would not be online prior to 2026.

Duke Generation

As of September 2011, Duke had 20,868 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 2011, the project was over 80% 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. They are scheduled to be available for the summer peak of 2012.

Jocassee Unit 1 and 2 Upgrades

This project is completed. Capacity additions reflect a 50 MW capacity uprate at the Jocassee pumped storage facility from increased efficiency of the new equipment. These uprates were included in the 2011 IRP analysis.

Buck CC Natural Gas Unit

The Company received the CPCN for this project in June 2008 and received the corresponding air permit in October 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 and commissioning activities are underway and the project is over 90% complete.

Dan River CC Natural Gas Unit

The Company received the CPCN for this project concurrently with the CPCN for the Buck CC project in June 2008 and received the air permit for this project in August 2009. The

620 MW Dan River CC unit is scheduled to be operational by the end of 2012. Construction is underway and the project is over 50% complete.

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 2015, 2016, and 2020, as well as 650 MW of new CC capacity in 2018. 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 1,924 MW of capacity between 2011 and 2015. Over 1,550 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.

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.

In its September 1, 2011 Annual Report, Duke stated that its analysis considered a portfolio based on full ownership of the 2,234 MW Lee Nuclear Station in 2021 and 2023, as well as a portfolio that reflects regional nuclear generation equivalent to the MW associated with Lee Nuclear Station spread over 2018 and 2028. The regional nuclear portfolio is illustrative of a potential regional nuclear portfolio and the Company developed this potential portfolio based on its recent activities to procure new nuclear generation and to sell a portion of the Lee Nuclear Station. Specifically, in February 2011, JEA (formerly Jacksonville Electric Authority), located in Jacksonville, Florida, signed an option to potentially purchase up to 20% of Lee Nuclear Station. In July 2011, the Company signed a letter of intent with Public Service Authority of South Carolina (Santee Cooper) to perform due diligence and potentially acquire an option for a minority interest (5 to 10% of the capacity of the two units) in Santee Cooper's 45% ownership of the planned new nuclear reactors at V.C. Summer (Summer) Nuclear Generating Station in South Carolina. The new Summer units are scheduled to be online between 2016 and 2019.

The results of the Company's analysis indicate that the regional nuclear portfolio is lower cost to customers in the base case and most scenarios, but the full nuclear portfolio was chosen for the 2011 IRP preferred plan because there are no firm commitments in place at this time for the regional nuclear portfolio. Although the regional nuclear portfolio assumes 10% of the Summer station is purchased, the Company's decision on whether and how much to purchase will be based on many factors, including the results of the due diligence related to Summer, the capacity need at the time of the decision, and the financial implications of the purchase on the Company. Duke will continue to assess opportunities to benefit from economies of scale and risk reduction in new resource decisions by considering the prospects for joint ownership and/or sales agreements for new nuclear generation resources.

NC Power / VEPCO Generation

As of September 2011, NC Power had 16,987 MW of existing Company owned generating capacity (summer rating). This excludes purchases and non-utility capacity. Of this total, only 480 MW is located in North Carolina.

On May 23, 2011, the Bear Garden CC Station, located in Buckingham County, Virginia, began service. Construction first began on this 590 MW CC unit in April 2009.

The Company previously noted that it had filed for a CPCN with the State Corporation Commission of Virginia (SCC) to construct and operate the Virginia City Hybrid Energy Center (VCHEC), a 585 MW clean coal powered electric generation facility located in Wise County, Virginia. On March 31, 2008, the SCC granted the CPCN and in June 2008 the Company began construction of the station. As of August 2011, the project was approximately 90% complete and proceeding on schedule. The station's targeted commercial operation date is Summer 2012.

The plant will use circulating fluidized bed (CFB) technology to burn a wide range of coals and waste coal from abandoned mines in the area. Additionally, the station's advanced design will allow the plant to consume up to 20% biomass fuel such as wood waste and wood byproducts. The station's two CFB boilers will also consume limestone to aid in the reduction of SO_2 emissions.

On May 2, 2011, the Company filed an application for SCC approval to construct and operate the Warren County Power Station, a 1,337 MW CC facility in Warren County, Virginia. Based on the Company's current schedule, this plant will be available to meet 2015 peak capacity and energy demand.

Nuclear power remains an important component of the Company's plan to achieve fuel diversity, stable long-term customer electric rates, system reliability, and low greenhouse gas emissions. On November 27, 2007, the NCR issued an Early Site Permit (ESP) to the Company's affiliate, Dominion Nuclear North Anna, LLC, for a site located at the Company's existing North Anna Power Station for a third unit. Also on November 27, 2007, the Company and Old Dominion Electric Cooperative (ODEC) filed an application with the NRC for a COL to build and operate a new nuclear reactor. On October 31, 2008, the NRC approved the transfer of the ESP to the Company and ODEC. The merger of Dominion Nuclear North Anna, LLC, into the Company became effective on December 1, 2008.

The two existing nuclear units will allow the third future unit to share some of the costs to meet safety and operating requirements. In March 2009, the Company issued a Request for Proposals (RFP) to license, engineer, procure, and construct a third nuclear unit at the North Anna Power Station. The Company selected Mitsubishi Heavy Industry's United States Advanced Pressurized-Water Reactor (APWR) for the design of the planned nuclear unit, although no 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.

In February 2011, ODEC informed the Company of its intent to no longer participate in the development of North Anna 3. The withdrawal of ODEC from the project does not change the Company's plans for North Anna 3 and it continues to move forward with the federal COL process. The Company is expecting the results of the NRC review by November 2013.

North Anna 3 would provide 1,453 MW of additional baseload capacity to the region by 2022. Although the Company has not committed to build the new unit, it intends to maintain the option to meet projected demand and energy requirements for electricity.

Between 2011 and 2022, NC Power may retire 33 units (2,088 MW) of older coal and CT generation. This group includes the two units (31 MW) at Kitty Hawk that began operation in 1971. Those two units will be retired by the end of 2011 and were put into cold reserve status on March 15, 2011, due to the age of the units. Prior to the actual retirement of any older coal and CT units, the condition and economics of these units will be evaluated by NC Power and the unit retirement dates may be revised.

7. RELIABILITY AND RESERVE MARGINS

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

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

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

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

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

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

Table 6: Projected Summer Reserve Margins for Progress, Duke, and NC Power (2011-2025)

	Reserve Margins
Progress	14.0% – 25.0%
Duke	16.2% – 26.2%
NC Power	11.0% – 16.7%

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. NERC audits owners, operators, and users for preparedness and educates, trains, and certifies industry personnel. NERC is a self-regulatory organization which is subject to oversight 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 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 2010 Long-Term Reliability Assessment indicates that the summer reserve margins for the SERC region will be adequate during the 2010-2019 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 1.7%, which is slightly below last year's 1.8% forecast. The average annual demand growth rate for the VACAR sub-region during this period is also forecast to be 1.7%. These forecasts are based on normal 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 were required to ensure that 0.02% of their retail electric sales in North Carolina come from solar energy resources. Additional requirements are effective in 2012 and subsequent years.

On October 1, 2011, the Commission submitted its fourth annual report to the Governor, the Environmental Review Commission, and the Joint Legislative Commission on Governmental Operations regarding Commission implementation of, and electric power supplier compliance with, the REPS. In addition, on September 28, 2011, the Commission filed its second biennial report to the same entities regarding cost allocations as required by Senate Bill 3. That report discusses allocations of utility costs for renewable energy, DSM/EE, 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 an RFP via which it selected a vendor, NYSE Blue, to design, build, and operate the tracking system. NC-RETS began operating July 1, 2010, consistent with the requirements of Session Law 2009-475.

Members of the public can access the NC-RETS web site at www.ncrets.org. The site's "resources" tab provides information regarding REPS activities and NC-RETS account holders. NC-RETS also provides an electronic bulletin board where RECs can be offered for purchase.

As of November 7, 2011:

- NC-RETS had issued 8,695,064 RECs and 252,601 energy efficiency certificates.
- 166 organizations, including electric power suppliers and owners of renewable energy facilities, had established accounts in NC-RETS.
- About 334 renewable energy facilities had been established as NC-RETS projects, enabling the issuance of RECs based on their energy production data.

At the end of 2010, each electric power supplier was required to have placed solar RECs that they acquired to meet their 2010 REPS solar set-aside obligation into a 2010 compliance account within NC-RETS. When the Commission concludes its review of each electric power supplier's REPS compliance report, the associated RECs are permanently retired. On August 23, 2011, the Commission approved 2010 REPS compliance for Duke, Blue Ridge, the City of Concord, the Town of Dallas, the Town of Forest City, the City of Highlands, the City of Kings Mountain and Rutherford. On November 10, 2011, the Commission approved 2010 REPS compliance for Progress, and the towns of Waynesville, Black Creek, Lucama, Sharpsburg and Stantonsburg. For all other North Carolina electric power suppliers, 2010 REPS compliance is pending before the Commission.

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

On September 1, 2011, the Commission filed its second biennial report to the Governor and the Joint Legislative Commission on Governmental Operations regarding proceedings for electric utilities involving EE and DSM cost recovery and incentives. That report lists the DSM and EE programs that have been reviewed by the Commission, and is available on the Commission's web site.

NC GreenPower

Launched in 2003, NC GreenPower began as the first, statewide multi-utility renewable energy program in the nation. NC GreenPower is an independent nonprofit working to help improve the quality of the environment in North Carolina. Voluntary contributions are accepted from residents and businesses that donate directly to NC GreenPower or through their utility bills to support local renewable energy and carbon offset projects. Renewable energy funds are used to pay approved generators across the state for each kWh of green energy they produce and put onto the electric grid from their project. Carbon offset contributions are used to pay carbon mitigation projects for every pound of greenhouse gas that is eliminated by their project. Funds support local projects and help create jobs.

As of November 2011, NC GreenPower had contracts with 585 green power generators, including 558 small solar photovoltaic (PV), 15 large solar PV, one small hydroelectric facility, nine wind facilities, and one landfill methane facility. According to NC GreenPower, 11,181 North Carolina electric consumers were subscribed to 35,436 100-kWh blocks of power per month, representing 42,523,200 kWh of renewable energy delivered to the electric grid annually, which is enough to power about 3,000 homes.

As of November 2011, NC GreenPower's Carbon Offset program had 395 customers subscribed to 723 blocks of greenhouse gas mitigation (1,000 pounds each), representing a total offset of 8,676,000 pounds of carbon dioxide equivalent per year. Annually, these donations are the environmental equivalent of planting 7,474,007 trees.

On August 1, 2011, NC GreenPower announced that Carbon Offset blocks are now double in value. Each $4 block now offsets 1,000 pounds of greenhouse gases. Once worth 500 pounds, the NC GreenPower Carbon Offset block has defied the market and increased in value. A participant can now offset the annual emissions of driving a mid-sized car 15,000 miles annually for just $4 a month, the environmental equivalent of planting 923 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. Participants (transmission-owning utilities, such as Duke and Progress, and transmission-dependent utilities, such as municipal electric systems and EMCs) identify the electric transmission projects that are needed to be built for reliability and estimate the costs of those upgrades.

The NCTPC's January 2011 report states that 14 major transmission projects are needed in North Carolina by the end of 2020 at an estimated cost of $473 million. This report also studied two "climate change" scenarios and estimated their transmission impacts and costs. The first hypothetical scenario studied was one in which 3,500 MW of un-scrubbed coal generation had to be retired. The study found that such a hypothetical future would not drive the need for any incremental large transmission projects. The other scenario that was studied was whether additional transmission would be needed if 3,000 MW of wind generation were built off the coast of North Carolina. The study concluded that it would cost at least $1.2 billion to build the high-voltage transmission lines that would be needed to move that power from North Carolina's coast inland to the large population centers.

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. On March 31, 2010, the Citizens to Protect Kituwah Valley and Swain County jointly filed a complaint against Duke. The complaint asserted that Duke should have been required to obtain such a certificate prior to upgrading an existing single circuit 66-kV transmission line to a double circuit 161-kV transmission line in the same location. On April 13, 2011, the Commission issued an order finding that Duke was not required to obtain a CPCN prior to building a tie station or upgrading the related transmission line. However, the Commission scheduled a hearing on the issues of whether Duke acted in a reasonable and appropriate manner in its siting and construction of the transmission line. The hearing was held August 2, 2011, in Bryson City, and the Commission's decision is pending.

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.

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

State Generator Interconnection Standards

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

In Session Law 2007-397, the General Assembly, among other things, directed the Commission to "[e]stablish standards for interconnection of renewable energy facilities and other nonutility-owned generation with a generation capacity of 10 megawatts or less to an electric public utility's distribution system; provided, however, that the Commission shall adopt, if appropriate, federal interconnection standards."

On June 9, 2008, the Commission issued an Order revising North Carolina's Interconnection Standard. The Commission used the federal standard as the starting point for all state-jurisdictional interconnections (regardless of the size of the generator), and made modifications to retain and improve upon the policy decisions made in 2005. The Commission's Order required regulated utilities to update any affected rate schedules, tariffs, riders, and service regulations to conform with the revised standard.

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

Net Metering

"Net metering" refers to a billing arrangement whereby a customer that owns and operates an electric generating facility is billed according to the difference over a billing period between the amount of energy the customer consumes and the amount of energy it generates. In Senate Bill 3, codified at G.S. 62.133.8(i)(6), the General Assembly required the Commission to consider whether it is in the public interest to adopt rules for electric public utilities for net metering of renewable energy facilities with a generation capacity of one megawatt or less.

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

10. FEDERAL ENERGY INITIATIVES

Open Access Transmission Tariff

In April 1996, the FERC issued Order Nos. 888 and 889, which established rules governing open access to electric transmission systems for wholesale customers and required the construction and use of an Open Access Same-time Information System (OASIS) for reserving transmission service. In Order No. 888, the FERC also required utilities to file standard, non-discriminatory 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.

In 2010 FERC opened a rulemaking regarding how to allocate the costs of large transmission projects in order to encourage development of renewable energy. The Commission and the Public Staff intervened in the proceeding, representing North Carolina electricity consumers. On July 21, 2011, the FERC issued a final rule entitled "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities," also known as "Order 1000." The Utilities Commission and the Public Staff jointly filed a request for rehearing, arguing that the rule infringes on state jurisdiction by mandating regional and inter-regional transmission planning processes and cost allocation methods. North Carolina's rehearing request is pending before FERC. If the rule remains unchanged, it will require transmission owners to make compliance filings in 2012 and 2013.

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 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 on to all transmission customers. Specifically, the Commission and the Public Staff argued that North Carolina citizens should not be required to pay the incremental cost of undergrounding 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. DOE is required to prepare a report to Congress every three years on the status of transmission congestion nationwide. On November 10, 2011, the DOE announced its plan for conducting a 2012 Congestion Study, which includes soliciting public comments, publishing a draft study with a 60-day comment period, and publishing a final report.

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 also covers 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 128

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

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

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

APPEARANCES:

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

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

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

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

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

Further, Commission Rule R8-67(b) requires any electric power supplier subject to Rule R8-60 to file a Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance plan as part of its IRP report. Within 150 days after the filing of each electric utility's biennial report, and within 60 days after the filing of each electric utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the electric utilities' IRP reports. Furthermore, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing.

The 2010 biennial integrated resource plans (IRPs) were filed by the following investor-owned utilities (IOUs): Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC); Duke Energy Carolinas, LLC (Duke); Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP); and the electric membership corporations (EMCs): North Carolina Electric Membership Corporation (NCEMC); Rutherford EMC (Rutherford), Piedmont EMC (Piedmont), Haywood EMC (Haywood), and EnergyUnited EMC (EU). In addition, REPS compliance plans were submitted by the IOUs, GreenCo Solutions, Inc. (GreenCo),[1] Halifax EMC (Halifax), and EU.

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

Procedural History

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

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

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

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

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

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

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

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

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

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

Based upon the foregoing, the information contained in the 2010 biennial IRPs, the 2010 REPS compliance plans, the comments and reply comments, and the Commission's entire record of this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. The IOUs' 15-year forecasts of native load requirements and other system capacity or firm energy obligations; supply-side and demand-side resources expected to satisfy those loads; and reserve margins thus produced are reasonable for purposes of this proceeding and should be approved.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Peak and Energy Forecasts

In the Public Staff's comments, it stated that all of the electric utilities use accepted econometric and end-use analytical models to forecast their peak and energy needs. As with any forecasting methodology, there is a degree of uncertainty associated with models that rely, in part, on assumptions that certain historical trends or relationships will continue in the future.

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

PEC

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

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

Duke

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

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

DNCP

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

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

shows that the predictions in the 2005 IRP were reasonably accurate with less than a 5% forecast error.

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

NCEMC

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

EU

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

Haywood

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

Piedmont

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

Rutherford

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

Summary of Load Forecasts

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

2011- 2025 Growth Rates
(After EE and DSM)

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

Reserve Margins

PEC

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

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

Duke

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

DNCP

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

DSM and EE

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

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

Evaluation of Resource Options

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

REPS Compliance Plan Review

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

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

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

Conclusions

Based upon the foregoing, the Commission finds that the IOUs' 15-year forecasts of native load requirements and other system capacity or firm energy obligations; supply-side and demand-side resources expected to satisfy those loads; and reserve margins thus produced are reasonable for purposes of this proceeding and should be approved. The 2010 biennial IRP reports and 2010 REPS compliance plans submitted by the IOUs are reasonable and should be approved.

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

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 5

Least Cost Resource Portfolio Selection

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

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

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

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

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

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

Evaluation of EE

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

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

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

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

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

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

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

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

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

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

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

- The potential benefits regarding grid stability;

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

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

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

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

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

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

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

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

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

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

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

- A lack of any adjustment for large customer statutory opt-out of utility EE and demand-side management programs, as permitted under G.S. 62-133.9;
- A lack of any adjustment for naturally occurring, customer-driven EE captured in the company load forecasts;
- Assumptions of unreasonably high participation rates that are not reflective of the current data for the utilities;
- *Reliance on market potential studies completed before the passage of the* Energy Independence and Security Act of 2007;
- A lack of any discussion of equipment life (also referred to as Rate of Turnover); and
- The inclusion of below efficiency standard impacts already captured in the utilities' load forecasts, thereby double-counting potential savings impacts.

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

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

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

Baseload Requirements

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Cost of Additional Nuclear Generation

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Greenhouse Gas Emissions

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

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

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

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

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

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

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

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

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

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

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

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

Existing Scrubbed Coal Units

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

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

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

Overly Optimistic Growth Projections

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

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

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

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

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

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

Convening a Workshop or Workgroup

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

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

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

Conclusions

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

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

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

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 6

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

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

Conclusion

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

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 7

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

PEC

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

Duke

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

Conclusion

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

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 8

In its comments, the Public Staff requested:

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

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

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

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

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

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

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

Conclusion

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

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 9

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

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

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

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

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

Conclusions

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

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

In its comments, the Public Staff requested:

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

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

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

Conclusions

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

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 13

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

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

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

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

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

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

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

Conclusions

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

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 14

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

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

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

Conclusions

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

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 15

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

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

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

Conclusions

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

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 16

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

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

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

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

Conclusions

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

IT IS, THEREFORE, ORDERED as follows:

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

2. That the 2010 biennial reports filed in this proceeding by the IOUs, NCEMC, Piedmont, Rutherford, EU, and Haywood are hereby approved.

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

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

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

6. That future IRP filings by all utilities shall continue to: (1) provide the amount of load and projected load growth for each wholesale customer under contract on a year-by-year basis through the terms of the current contract, segregate actual and projected growth rates of retail and wholesale loads, and explain any difference in actual and projected growth rates between retail and wholesale loads, and (2) for any amount of undesignated load, detail each potential customer's current supply arrangements and explain the basis for the utility's reasonable expectation for serving each such customer.

7. That French Broad and Blue Ridge shall not be required to file individual IRPs.

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

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

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

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

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

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

ISSUED BY ORDER OF THE COMMISSION.

This the 26th day of October, 2011.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount

Gail L. Mount, Deputy Clerk

kh102611.01

Progress Energy Carolinas

Table 1 2010 Annual IRP (Summer)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
GENERATION CHANGES															
Sited Additions	635		920	625											
Undesignated Additions (1)						126		528	176	276	804	606		176	176
Planned Project Uprates	8	55		10	24										
Pollution Control Derates															
Retirements			(397)	(604)	(487)										
INSTALLED GENERATION															
Nuclear	3,490	3,545	3,545	3,555	3,579	3,579	3,579	3,579	3,579	3,579	3,579	3,579	3,579	3,579	3,579
Fossil	5,190	5,190	4,793	4,189	3,702	3,702	3,702	3,702	3,702	3,702	3,702	3,702	3,702	3,702	3,702
Combined Cycle	1,171	1,171	2,091	2,716	2,716	2,716	2,716	2,716	2,716	2,716	2,716	2,716	2,716	2,716	2,716
Combustion Turbine	3,152	3,152	3,152	3,152	3,152	3,152	3,152	3,152	3,152	3,152	3,152	3,152	3,152	3,152	3,152
Hydro	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225
Undesignated (1)						126	126	654	830	1,106	1,910	2,516	2,516	2,692	2,868
TOTAL INSTALLED *	13,228	13,283	13,806	13,837	13,374	13,500	13,500	14,028	14,204	14,480	15,284	15,890	15,890	16,066	16,242
PURCHASES & OTHER RESOURCES															
SEPA	95	95	109	109	109	109	109	109	109	109	109	109	109	109	109
NUG QF - Cogen **	161	161	161	161	161	161	161	161	161	161	161	161	161	161	161
NUG QF - Renewable ***	83	119	120	130	108	112	112	67	67	64	51	52	52	52	52
Butler Warner		220	220	220	220	220	220								
Anson CT Tolling Purchase			336	336	336	336	336	336	336	336	336	336	336	336	336
Broad River CT	816	816	816	816	816	816	816	816	816	816	336				
Southern CC Purchase - ST	150														
Southern CC Purchase - LT	145	145	145	145	145	145	145	145	145						
TOTAL SUPPLY RESOURCES	14,677	14,839	15,712	15,753	15,269	15,398	15,398	15,662	15,838	15,966	16,277	16,547	16,547	16,723	16,900
PEAK DEMAND															
Retail	9,189	9,389	9,621	9,875	10,099	10,295	10,453	10,615	10,784	10,958	11,132	11,306	11,483	11,664	11,850
Wholesale	3,050	3,219	4,012	4,075	4,100	4,140	4,187	4,215	4,277	4,314	4,376	4,423	4,489	4,541	4,608
Firm (Duke Area)	150	100	150	150	150	150	150	150	150	150	150	150	150	150	0
OBLIGATION BEFORE DSM	12,389	12,708	13,782	14,099	14,348	14,585	14,789	14,979	15,211	15,422	15,657	15,878	16,122	16,355	16,458
DSM & EE	611	824	925	1,015	1,095	1,170	1,240	1,303	1,365	1,425	1,478	1,532	1,590	1,646	1,701
OBLIGATION AFTER DSM	11,778	11,884	12,857	13,084	13,253	13,415	13,550	13,676	13,846	13,997	14,180	14,346	14,532	14,709	14,757
RESERVES (2)	2,900	2,954	2,854	2,669	2,016	1,983	1,849	1,986	1,992	1,968	2,098	2,201	2,015	2,015	2,142
Capacity Margin (3)	20%	20%	18%	17%	13%	13%	12%	13%	13%	12%	13%	13%	12%	12%	13%
Reserve Margin (4)	25%	25%	22%	20%	15%	15%	14%	15%	14%	14%	15%	15%	14%	14%	15%
ANNUAL SYSTEM ENERGY (GWh)	62,765	63,715	65,899	67,085	68,023	69,040	69,839	70,581	71,454	72,370	73,305	74,164	75,059	75,983	76,813

Notes:

* TOTAL INSTALLED includes Mod-24 unit rating changes.

** EPCOR Capacity has been included but subject to change pending arbitration outcome.

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

Footnotes:

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

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

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

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

Progress Energy Carolinas

Table 2 2010 Annual IRP (Winter)

	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
GENERATION CHANGES															
Sited Additions		894	1,049	717											
Undesignated Additions (1)						147			603	201	281	884	674		201
Planned Project Uprates	4	25	30	10		28									
Pollution Control Derates															
Retirements			(417)	(616)	(500)										
INSTALLED GENERATION															
Nuclear	3,626	3,651	3,681	3,691	3,691	3,719	3,719	3,719	3,719	3,719	3,719	3,719	3,719	3,719	3,719
Fossil	5,284	5,284	4,867	4,251	3,751	3,751	3,751	3,751	3,751	3,751	3,751	3,751	3,751	3,751	3,751
Combined Cycle	610	1,304	2,353	3,070	3,070	3,070	3,070	3,070	3,070	3,070	3,070	3,070	3,070	3,070	3,070
Combustion Turbine	3,657	3,657	3,657	3,657	3,657	3,657	3,657	3,657	3,657	3,657	3,657	3,657	3,657	3,657	3,657
Hydro	229	229	229	229	229	229	229	229	229	229	229	229	229	229	229
Undesignated (1)						147	147	147	750	951	1,232	2,116	2,790	2,790	2,991
TOTAL INSTALLED *	13,406	14,125	14,787	14,898	14,398	14,573	14,573	14,573	15,176	15,377	15,658	16,542	17,216	17,216	17,417
PURCHASES & OTHER RESOURCES															
SEPA	95	95	109	109	109	109	109	109	109	109	109	109	109	109	109
NUG QF - Cogen **	161	161	161	161	161	161	161	161	161	161	161	161	161	161	161
NUG QF - Renewable ***	83	119	120	130	108	112	112	67	67	64	51	52	52	52	52
Butler Warner			260	260	260	260	260								
Anson CT Tolling Purchase			365	365	365	365	365	365	365	365	365	365	365	365	365
Broad River CT	888	888	888	888	888	888	888	888	888	888	888	389			
Southern CC Purchase - ST	150														
Southern CC Purchase - LT	145	145	145	145	145	145	145	145	145						
TOTAL SUPPLY RESOURCES	14,927	15,533	16,834	16,955	16,433	16,612	16,612	16,307	16,910	16,963	17,231	17,617	17,902	17,902	18,104
OBLIGATION BEFORE DSM	11,158	11,441	12,566	12,848	13,067	13,272	13,446	13,605	13,801	13,979	14,180	14,367	14,576	14,775	14,844
DSM & EE	493	654	695	737	773	802	834	867	901	938	971	1,006	1,044	1,081	1,119
OBLIGATION AFTER DSM	10,664	10,787	11,871	12,112	12,294	12,470	12,612	12,738	12,900	13,041	13,209	13,362	13,532	13,694	13,725
RESERVES (2)	4,263	4,746	4,962	4,843	4,139	4,142	4,000	3,569	4,010	3,922	4,023	4,256	4,370	4,209	4,378
Capacity Margin (3)	29%	31%	29%	29%	25%	25%	24%	22%	24%	23%	23%	24%	24%	24%	24%
Reserve Margin (4)	40%	44%	42%	40%	34%	33%	32%	28%	31%	30%	30%	32%	32%	31%	32%

Notes:

* TOTAL INSTALLED includes Mod-24 unit rating changes.

** EPCOR Capacity has been included but subject to change pending arbitration outcome.

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

Footnotes:

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

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

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

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

**Summer Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2010 Annual Plan**

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Forecast																				
1 Duke System Peak	17,571	17,840	18,115	18,481	18,864	19,307	19,747	20,212	20,651	21,031	21,388	21,698	22,018	22,343	22,672	23,010	23,343	23,669	24,034	24,384
Reductions to Load Forecast																				
2 New EE Programs	(42)	(81)	(141)	(201)	(259)	(317)	(396)	(457)	(496)	(553)	(633)	(633)	(633)	(633)	(633)	(633)	(633)	(633)	(633)	(633)
3 Adjusted Duke System Peak	**17,529**	**17,759**	**17,974**	**18,280**	**18,605**	**18,990**	**19,351**	**19,755**	**20,155**	**20,478**	**20,755**	**21,065**	**21,385**	**21,710**	**22,039**	**22,377**	**22,710**	**23,056**	**23,401**	**23,751**
Cumulative System Capacity																				
4 Generating Capacity	19,817	19,756	20,564	21,064	21,082	20,372	20,382	20,409	20,489	20,519	20,519	20,519	20,519	20,519	20,519	20,519	20,519	20,519	20,519	20,519
5 Capacity Additions	64	1,465	666	18	370	10	27	81	30	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	(113)	(658)	(166)	0	(1,080)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	19,756	20,564	21,064	21,082	20,372	20,382	20,409	20,489	20,519	20,519	20,519	20,519	20,519	20,519	20,519	20,519	20,519	20,519	20,519	20,519
Purchase Contracts																				
9 Cumulative Purchase Contracts	270	270	211	123	100	100	100	100	100	97	96	87	87	87	87	87	87	87	87	87
Sales Contracts																				
10 Catawba Owner Backstand	(73)																			
11 Catawba Owner Load Following Agreement																				
12 Cumulative Future Resource Additions																				
Base Load	0	0	0	0	0	0	0	0	0	0	1,117	1,117	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234
Peaking/Intermediate	0	0	0	0	0	0	740	740	1,480	1,480	1,480	1,480	1,480	1,480	1,480	1,480	2,130	2,130	2,780	3,080
Renewables	36	125	154	259	378	379	380	450	453	424	471	474	472	477	483	490	497	505	512	520
13 Cumulative Production Capacity	**19,989**	**20,958**	**21,429**	**21,465**	**20,851**	**20,861**	**21,629**	**21,780**	**22,553**	**22,521**	**23,684**	**23,678**	**24,793**	**24,798**	**24,804**	**24,811**	**25,468**	**25,476**	**26,133**	**26,441**
Reserves w/o Demand-Side Management																				
14 Generating Reserves	2,460	3,199	3,455	3,185	2,246	1,871	2,278	2,025	2,398	2,043	2,929	2,613	3,408	3,088	2,765	2,434	2,758	2,420	2,732	2,690
15 % Reserve Margin	**14.0%**	**18.0%**	**19.2%**	**17.4%**	**12.1%**	**9.9%**	**11.8%**	**10.2%**	**11.9%**	**10.0%**	**14.1%**	**12.4%**	**15.9%**	**14.2%**	**12.5%**	**10.9%**	**12.1%**	**10.5%**	**11.7%**	**11.3%**
16 % Capacity Margin	12.3%	15.3%	16.1%	14.8%	10.8%	9.0%	10.5%	9.3%	10.6%	9.1%	12.4%	11.0%	13.7%	12.5%	11.1%	9.8%	10.8%	9.5%	10.5%	10.2%
Demand-Side Management																				
17 Cumulative DSM Capacity	961	1,168	1,255	1,267	1,267	1,267	1,267	1,267	1,267	1,267	1,267	1,267	1,267	1,267	1,267	1,267	1,267	1,267	1,267	1,267
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	668	875	962	974	974	974	974	974	974	974	974	974	974	974	974	974	974	974	974	974
18 Cumulative Equivalent Capacity	20,950	22,126	22,684	22,732	22,118	22,129	22,897	23,047	23,820	23,789	24,952	24,946	26,061	26,066	26,071	26,078	26,736	26,743	27,401	27,709
Reserves w/ DSM																				
19 Generating Reserves	3,421	4,367	4,710	4,452	3,513	3,139	3,546	3,292	3,665	3,311	4,197	3,881	4,676	4,356	4,032	3,701	4,026	3,687	4,000	3,958
20 % Reserve Margin	**19.5%**	**24.6%**	**26.2%**	**24.4%**	**18.9%**	**16.5%**	**18.3%**	**16.7%**	**18.2%**	**16.2%**	**20.2%**	**18.4%**	**21.9%**	**20.1%**	**18.3%**	**16.5%**	**17.7%**	**16.0%**	**17.1%**	**16.7%**
21 % Capacity Margin	16.3%	19.7%	20.8%	19.6%	15.9%	14.2%	15.5%	14.3%	15.4%	13.9%	16.8%	15.6%	17.9%	16.7%	15.5%	14.2%	15.1%	13.8%	14.6%	14.3%

Winter Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2010 Annual Plan

	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	2018	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Load Forecast																					
1 Duke System Peak	16,919	17,186	17,481	17,839	18,211	18,624	19,029	19,455	20,212	19,848	20,189	20,504	20,795	21,094	21,396	21,699	22,011	22,318	22,633	22,950	23,270
Reductions to Load Forecast																					
2 New EE Programs	(34)	(62)	(153)	(227)	(281)	(374)	(393)	(525)	(457)	(537)	(579)	(750)	(727)	(727)	(727)	(727)	(727)	(727)	(727)	(727)	(727)
3 Adjusted Duke System Peak	**16,885**	**17,124**	**17,328**	**17,612**	**17,930**	**18,250**	**18,636**	**18,930**	**19,755**	**19,311**	**19,610**	**19,754**	**20,068**	**20,367**	**20,669**	**20,972**	**21,284**	**21,591**	**21,906**	**22,223**	**22,543**
Cumulative System Capacity																					
4 Generating Capacity	20,567	20,567	20,928	21,791	21,814	21,462	21,122	21,131	20,409	21,158	21,239	21,269	21,269	21,269	21,269	21,269	21,269	21,269	21,269	21,269	21,269
5 Capacity Additions	0	684	1,465	46	18	370	10	27	0	81	30	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	0	(12)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	0	(311)	(602)	(24)	(370)	(710)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	20,567	20,928	21,791	21,814	21,462	21,122	21,131	21,158	20,409	21,239	21,269	21,269	21,269	21,269	21,269	21,269	21,269	21,269	21,269	21,269	21,269
Purchase Contracts																					
9 Cumulative Purchase Contracts	277	277	218	123	100	100	100	100	100	100	97	96	87	87	87	87	87	87	87	87	87
Sales Contracts																					
10 Catawba Owner Backstand	(73)	(73)																			
11 Catawba Owner Load Following Agreement	(50)																				
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	2,234
Peaking/Intermediate	0	0	0	0	0	0	0	740	740	740	1,480	1,480	1,480	1,480	1,480	1,480	1,480	1,480	2,130	2,130	2,780
Renewables	12	36	125	154	259	378	379	380	450	450	453	424	471	474	472	477	483	490	497	505	512
13 Cumulative Production Capacity	**20,733**	**21,168**	**22,134**	**22,091**	**21,822**	**21,600**	**21,611**	**22,379**	**21,699**	**22,529**	**23,299**	**23,270**	**24,425**	**24,428**	**25,543**	**25,548**	**25,553**	**25,560**	**26,218**	**26,225**	**26,883**
Reserves w/o Demand-Side Management																					
14 Generating Reserves	3,848	4,044	4,806	4,479	3,892	3,350	2,975	3,449	1,944	3,218	3,689	3,516	4,357	4,061	4,874	4,576	4,269	3,969	4,312	4,002	4,340
15 % Reserve Margin	**22.8%**	**23.6%**	**27.7%**	**25.4%**	**21.7%**	**18.4%**	**16.0%**	**18.2%**	**9.8%**	**16.7%**	**18.8%**	**17.8%**	**21.7%**	**19.9%**	**23.6%**	**21.8%**	**20.1%**	**18.4%**	**19.7%**	**18.0%**	**19.3%**
16 % Capacity Margin	18.6%	19.1%	21.7%	20.3%	17.8%	15.5%	13.8%	15.4%	9.0%	14.3%	15.8%	15.1%	17.8%	16.6%	19.1%	17.9%	16.7%	15.5%	16.4%	15.3%	16.1%
Demand-Side Management																					
17 Cumulative DSM Capacity	640	788	841	841	841	841	841	841	1,267	841	841	841	841	841	841	841	841	841	841	841	841
IS / SG	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293	293
Power Share / Power Manager	347	494	548	548	548	548	548	548	974	548	548	548	548	548	548	548	548	548	548	548	548
18 Cumulative Equivalent Capacity	21,373	21,955	22,975	22,932	22,663	22,442	22,452	23,220	22,966	23,371	24,141	24,111	25,266	25,269	26,384	26,389	26,395	26,402	27,059	27,067	27,724
Reserves w/ DSM																					
19 Generating Reserves	4,488	4,831	5,647	5,320	4,733	4,192	3,816	4,290	3,211	4,060	4,531	4,357	5,198	4,902	5,715	5,417	5,111	4,811	5,153	4,844	5,181
20 % Reserve Margin	**26.6%**	**28.2%**	**32.6%**	**30.2%**	**26.4%**	**23.0%**	**20.5%**	**22.7%**	**16.3%**	**21.0%**	**23.1%**	**22.1%**	**25.9%**	**24.1%**	**27.7%**	**25.8%**	**24.0%**	**22.3%**	**23.5%**	**21.8%**	**23.0%**
21 % Capacity Margin	21.0%	22.0%	24.6%	23.2%	20.9%	18.7%	17.0%	18.5%	14.0%	17.4%	18.8%	18.1%	20.6%	19.4%	21.7%	20.5%	19.4%	18.2%	19.0%	17.9%	18.7%

ASSUMPTIONS OF LOAD, CAPACITY, AND RESERVES TABLE

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

1. Planning is done for the peak demand for the Duke System including Nantahala. Nantahala became a division of Duke Energy Carolinas in 1998.

4. Generating Capacity must be online by June 1 to be included in the available capacity for the summer peak of that year. Capacity must be online by Dec 1 to be included in the available capacity for the winter peak of that year. Includes 91 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for NCMPA1 firm capacity sale.
   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 by the summer of 2011 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).
   Capacity Additions include the conversion of Lee Steam Station from coal to natural gas in 2015.
   Capacity Additions include Duke Energy Carolinas hydro units scheduled to be repaired and returned to service. These units are returned to service in the 2011-2017 timeframe and total 34 MW.
   Also included is a 205 MW capacity increase due to nuclear uprates at Catawba, McGuire, and Oconee. Timing of these uprates is shown from 2012-2019

6. The expected Capacity Derates reflect the impact of parasitic loads from planned scrubber additions to Cliffside 5.

7. The 113 MW capacity retirement in summer 2011 represents the projected retirement dates for Buck Units 3-4.
   The 658 MW capacity retirement in summer 2012 represents the projected retirement date for Dan River Steam Station units 1 and 2 (134 MW), Cliffside Steam Station units 1-4 (198 MW), and 326 MWs of old fleet CT retirements.
   The 166 MW capacity retirement in summer 2013 represents the projected retirement date for Dan River Steam Station unit 3 (142 MW) and 24 MWs of old fleet CT retirements.
   The 1080 MW capacity retirement in summer 2015 represents the projected retirement date for Lee Steam Station (370 MW), Buck Steam Station units 5 and 6 (256 MW) and Riverbend Steam Station units 4-7 (454 MW).
   The NRC has issued renewed energy facility operating licenses for all Duke Energy Carolinas' nuclear facilities.
   The Hydro facilities for which Duke has submitted an application to FERC for licence renewal are assumed to continue operation through the planning horizon.
   All retirement dates are subject to review on an ongoing basis.

10-11. Two firm wholesale agreements are effective between Duke Energy Carolinas and NCMPA1. The first is a 50 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 2011.

9. Cumulative Purchase Contracts have several components:

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

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)														
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1. Utility Peak Load (MW)																			
A. Summer																			
1a. Base Forecast	17,741	16,758	15,917	16,563	17,099	17,541	18,315	18,865	19,247	19,576	20,039	20,404	20,707	21,021	21,357	21,588	21,896	22,273	22,581
1b. Additional Forecast																			
NCEMC	150	150	150	150	150	150	150	150	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency				-	-	-21	-94	-215	-283	-347	-286	-278	-270	-260	-262	-264	-266	-267	-268
3. Demand Response(2)				-	-	-39	-154	-243	-301	-352	-396	-434	-465	-490	-511	-524	-535	-543	-550
4. Demand Response-Existing(2)(3)	-23	-22	-18	-17	-15	-14	-13	-11	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10
5. Peak Adjustment				239	281	524	941	-	-	-	-	-	-	-	-	-	-	-	-
6. Adjusted Load	17,891	16,908	16,067	16,952	17,530	18,194	19,312	18,800	18,964	19,229	19,753	20,126	20,437	20,761	21,095	21,324	21,630	22,006	22,313
7. % Increase in Adjusted Load (from previous year)		-5.5%	-5.0%	5.5%	3.4%	3.8%	6.1%	-2.7%	0.9%	1.4%	2.7%	1.9%	1.5%	1.6%	1.6%	1.1%	1.4%	1.7%	1.4%
B. Winter																			
1a. Base Forecast	15,615	14,637	15,427	14,236	14,434	14,804	15,568	15,958	16,214	16,470	16,738	17,246	17,496	17,630	17,897	18,005	18,255	18,770	18,947
1b. Additional Forecast																			
NCEMC	150	150	150	141	143	145	146	147	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency				-	-	-23	-90	-149	-203	-255	-229	-227	-224	-221	-223	-225	-226	-228	-230
3. Demand Response(2)				-	- -	-	-28	-66	-76	-85	-92	-97	-100	-104	-107	-111	-114	-118	-119
4. Demand Response-Existing(2)(3)	-23	-22	-18	-17	-15	-14	-13	-11	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10	-10
5. Adjusted Load	15,765	14,787	15,577 0	14,376	14,577	14,926	15,625	15,956	16,011	16,215	16,508	17,019	17,272	17,409	17,675	17,780	18,028	18,542	18,717
6. % Increase in Adjusted Load		-6.2%	5.3%	-7.7%	1.4%	2.4%	4.7%	2.1%	0.3%	1.3%	1.8%	3.1%	1.5%	0.8%	1.5%	0.6%	1.4%	2.9%	0.9%
2. Energy (GWh)																			
A. Base Forecast	85,771	83,547	82,501	84,023	86,533	89,028	93,205	95,897	97,845	100,089	101,978	103,517	104,944	106,756	108,166	109,749	111,404	113,265	114,566
B. Additional Forecast																			
NCEMC				605	619	645	658	676	-	-	-	-	-	-	-	-	-	-	-
ODECsupp				119	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Conservation & Demand Response				-251	-362	-1,108	-2,053	-3,088	-4,007	-4,304	-3,942	-3,886	-3,827	-3,768	-3,776	-3,784	-3,789	-3,791	-3,797
D. Demand Response-Existing(2)(3)	-3	-3	-2 0	-2 0	-2	-2	-2	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
E. Adjusted Energy	85,771	83,547	82,501	84,496	86,790	88,565	91,812	93,489	93,840	95,788	98,044	99,636	101,117	102,988	104,390	105,966	107,615	109,474	110,769
F. % Increase in Adjusted Energy		-2.6%	-1.3%	2.4%	2.7%	2.0%	3.7%	1.8%	0.4%	2.1%	2.4%	1.6%	1.5%	1.9%	1.4%	1.5%	1.6%	1.7%	1.2%

(1) Actual metered data.

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

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

APPENDIX 2I - REQUIRED RESERVE MARGIN

Company Name: Virginia Electric and Power Company **Schedule 6**

POWER SUPPLY DATA (continued)

	(ACTUAL)				(PROJECTED)														
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
I. Reserve Margin[1]																			
(Including Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW[1]	494	1,312	1,964	3,021	2,958	3,177	2,655	2,205	2,223	2,252	2,310	2,351	2,385	2,421	2,458	2,483	2,517	2,558	2,592
b. Percent of Load	2.9%	7.8%	12.2%	17.8%	16.9%	17.4%	13.7%	11.7%	11.7%	11.7%	11.7%	11.7%	11.7%	11.7%	11.7%	11.6%	11.6%	11.6%	11.6%
c. Actual Reserve Margin[4]	N/A	N/A	N/A	7.98%	8.68%	7.72%	3.06%	6.60%	10.96%	9.77%	5.99%	8.16%	12.01%	12.06%	12.29%	12.01%	12.33%	12.69%	11.19%
2. Winter Reserve Margin																			
a. MW(1)	N/A	N/A	N/A	6,707	6,272	6,817	7,512	6,353	5,418	6,055	6,951	5,426	5,556	6,561	6,644	6,819	6,944	6,789	7,389
b. Percent of Load	N/A	N/A	N/A	46.7%	43.0%	45.7%	48.1%	39.8%	33.8%	37.3%	42.1%	31.9%	32.2%	37.7%	37.6%	38.4%	38.5%	36.6%	39.5%
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]	494	1,312	1,964	3,010	2,821	3,040	2,518	2,068	2,086	2,115	2,173	2,214	2,248	2,284	2,321	2,346	2,380	2,421	2,455
b. Percent of Load	2.9%	7.8%	12.2%	17.8%	16.1%	16.7%	13.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%
c. Actual Reserve Margin[4]	N/A	N/A	N/A	7.9%	7.9%	7.0%	2.4%	5.9%	10.2%	9.1%	5.3%	7.5%	11.3%	11.4%	11.6%	11.4%	11.7%	12.1%	10.6%
2. Winter Reserve Margin																			
a. MW[1]	N/A	N/A	N/A	6,693	6,132	6,677	7,372	6,213	5,278	5,915	6,811	5,286	5,416	6,421	6,504	6,679	6,804	6,649	7,249
b. Percent of Load	N/A	N/A	N/A	46.6%	43.0%	45.7%	48.1%	39.8%	33.8%	37.3%	42.1%	31.9%	32.2%	37.7%	37.6%	38.4%	38.5%	36.6%	39.5%
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 one unit in cold reserve.

(3) The Company and PJM forecasts a summer peak throughout the Planning Period.

(4) Does not include spot purchases of capacity.

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

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

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Requirements															
20 EMC Demand (1)	2,976	3,024	3,113	3,163	3,214	3,265	3,317	3,369	3,423	3,478	3,534	3,591	3,648	3,706	3,766
Existing DSM (2)	67	59	53	48	44	42	41	41	41	41	41	41	41	41	41
Net Peak Demand	2,909	2,964	3,060	3,115	3,170	3,223	3,276	3,328	3,382	3,437	3,493	3,550	3,607	3,665	3,725
Capacity Resources															
Catawba (3)	682	682	682	682	682	682	682	682	682	682	682	682	682	682	682
NCEMC CTs (4)	622	622	678	678	678	678	678	678	678	678	678	678	678	678	678
Diesels	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Total Capacity Resources	1,322	1,322	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378
Purchased Resources (5)															
AEP Purchases	150	150	0	0	0	0	0	0	0	0	0	0	0	0	0
PEC SORs	870	870	920	970	970	970	970	970	970	550	375	225	0	0	0
PEC PPAs	350	300	1,139	1,129	1,164	1,199	1,234	1,270	1,305	1,758	1,968	2,153	2,414	2,452	2,339
Duke PPAs	72	72	72	72	72	97	97	97	97	122	122	122	122	122	122
Southern PPAs	0	225	225	225	225	225	270	270	360	360	360	360	360	360	360
SCE&G PPA	250	250	0	0	0	0	0	0	0	0	0	0	0	0	0
Dominion PPA	150	150	150	150	0	0	0	0	0	0	0	0	0	0	0
SEPA Allocations (6)	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
PJM UCAP (7)	116	122	29	0	91	93	96	99	103	107	111	115	120	124	129
Total Purchased Resources	2,029	2,210	2,606	2,617	2,593	2,655	2,738	2,777	2,906	2,968	3,007	3,046	3,087	3,129	3,021
Obligations															
Capacity Sale to Independent Members	376	376	259	260	216	216	216	216	216	209	206	203	199	199	196
Southern PSA	0	100	100	100	100	100	100	100	100	100	100	0	0	0	0
PEC Tolling	0	0	339	339	339	339	339	339	339	339	339	339	339	339	339
Reserves (8)	81	99	62	62	62	62	67	67	79	79	79	91	91	91	91
Net Resources for Participating Members	2,894	2,957	3,224	3,234	3,254	3,316	3,394	3,433	3,550	3,619	3,661	3,791	3,836	3,878	3,773
Undesignated DSM / EE Resources (9)	20	30	40	51	63	75	86	87	89	89	90	92	93	95	96
Undesignated Renewable Resources (9)	6	18	25	25	27	27	27	37	82	85	88	112	114	116	118
Undesignated Future Conventional Resources	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual Energy (GWh) (10)	12,627	13,088	13,561	13,773	13,987	14,203	14,422	14,643	14,869	15,099	15,332	15,570	15,811	16,054	16,293
Annual Energy after EE (GWh) (10)	12,518	12,926	13,347	13,501	13,653	13,808	13,972	14,192	14,411	14,634	14,861	15,091	15,325	15,561	15,792

Notes:

(1) Total Demand is NCEMC's Participating Member coincident peak (NCEMC CP) measured at generation from the NCEMC 2009 Load Forecast

(2) "Existing DSM": Existing demand side management includes customer owned generation, interruptible load and residential load management resources

(3) "Catawba Resource": Catawba Nuclear Station ownership capacity reflects both Participating and Independent Members, along with the guaranteed capacity of the reliability exchange agreement

(4) Addition of sixth CT at Hamlet CT Plant with projected commercial operation date of May 2013

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

(6) SEPA allocations are for Participating Members

(7) PJM UCAP purchases include estimated PJM reserve requirements

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

(9) Undesignated DSM / Energy Efficiency & Renewable resources included in NCEMC's 2010 IRP

(10) Energy values are measured at generation for Participating Members from the NCEMC 2009 Load Forecast

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

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Requirements															
20 EMC Demand (1)	2,934	2,995	3,062	3,111	3,163	3,213	3,264	3,314	3,366	3,418	3,472	3,526	3,583	3,638	3,696
Existing DSM (2)	56	52	49	44	44	42	41	41	41	41	41	41	41	41	41
Net Peak Demand	2,878	2,943	3,013	3,067	3,119	3,171	3,223	3,273	3,325	3,378	3,431	3,485	3,542	3,597	3,655
Capacity Resources															
Catawba (3)	682	682	682	682	682	682	682	682	682	682	682	682	682	682	682
NCEMC CTs (4)	622	622	622	678	678	678	678	678	678	678	678	678	678	678	678
Diesels	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Total Capacity Resources	1,322	1,322	1,322	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378	1,378
Purchased Resources (5)															
AEP Purchases	150	150	0	0	0	0	0	0	0	0	0	0	0	0	0
PEC SORs	870	870	920	970	970	970	970	970	970	550	375	225	0	0	0
PEC PPAs	350	300	1,226	1,216	1,250	1,287	1,323	1,360	1,398	1,852	2,063	2,250	2,513	2,553	2,441
Duke PPAs	72	72	72	72	72	97	97	97	97	122	122	122	122	122	122
Southern PPAs	0	225	225	225	225	225	270	270	360	360	360	360	360	360	360
SCE&G PPA	250	250	0	0	0	0	0	0	0	0	0	0	0	0	0
Dominion PPA	150	150	150	150	0	0	0	0	0	0	0	0	0	0	0
SEPA Allocations (6)	71	71	71	71	71	71	71	71	71	71	71	71	71	71	71
PJM UCAP (7)	116	122	29	0	91	93	96	99	103	107	111	115	120	124	129
Total Purchased Resources	2,029	2,210	2,693	2,704	2,679	2,743	2,827	2,867	2,999	3,062	3,102	3,143	3,186	3,230	3,123
Obligations															
Capacity Sale to Independent Members	376	376	259	260	216	216	216	216	216	209	206	203	199	199	196
Southern PSA	0	100	100	100	100	100	100	100	100	100	100	0	0	0	0
PEC Tolling	0	0	339	339	339	339	339	339	339	339	339	339	339	339	339
Reserves (8)	81	99	55	62	62	62	67	67	79	79	79	91	91	91	91
Net Resources for Participating Members	2,894	2,957	3,262	3,321	3,340	3,404	3,483	3,523	3,643	3,713	3,756	3,888	3,935	3,979	3,875
Undesignated DSM / EE Resources (9)	20	30	40	51	63	75	86	87	89	89	90	92	93	95	96
Undesignated Renewable Resources (9)	6	18	25	25	27	27	27	37	82	85	88	112	114	116	118
Undesignated Future Conventional Resources	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Annual Energy (GWh) (10)	12,627	13,088	13,561	13,773	13,987	14,203	14,422	14,643	14,869	15,099	15,332	15,570	15,811	16,054	16,293
Annual Energy after EE (GWh) (10)	12,518	12,926	13,347	13,501	13,653	13,808	13,972	14,192	14,411	14,634	14,861	15,091	15,325	15,561	15,792

Notes:

(1) Total Demand is NCEMC's Participating Member coincident peak (NCEMC CP) measured at generation from the NCEMC 2009 Load Forecast

(2) "Existing DSM": Existing demand side management includes customer owned generation, interruptible load and residential load management resources

(3) "Catawba Resource": Catawba Nuclear Station ownership capacity reflects both Participating and Independent Members, along with the guaranteed capacity of the reliability exchange agreement

(4) Addition of sixth CT at Hamlet CT Plant with projected commercial operation date of May 2013

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

(6) SEPA allocations are for Participating Members

(7) PJM UCAP purchases include estimated PJM reserve requirements

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

(9) Undesignated DSM / Energy Efficiency & Renewable resources included in NCEMC's 2010 IRP

(10) Energy values are measured at generation for Participating Members from the NCEMC 2009 Load Forecast

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

Piedmont EMC - Duke Control Area

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PEAK (MW) (1)	96	98	100	103	105	107	109	112	114	116	119	121	124	126	129
ANNUAL ENERGY (GWh) (1)	132	135	138	141	144	147	150	154	157	160	163	167	170	173	177

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

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

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

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Requirements:															
PEAK (MW) (1)	31	31	32	33	33	34	35	35	36	37	38	39	39	40	41
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)	20	24	25	27	27	28	29	29	30	31	32	33	33	34	35
TOTAL RESOURCES (MW)	31	31	32	33	33	34	35	35	36	37	38	39	39	40	41
RESERVE CAPACITY (MW) (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL ENERGY (GWh) (1)	413	425	434	443	453	462	472	482	492	502	513	523	534	544	555

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

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PEAK (MW) (1)	127	130	132	135	138	141	144	147	150	154	157	160	163	167	170
ANNUAL ENERGY (GWh) (1)	545	560	572	585	597	609	622	636	649	662	676	690	704	718	732
ANNUAL ENERGY (GWh) (1) (Including Impact of Energy Efficiency Programs)	538	550	559	568	577	586	596	609	622	636	650	663	677	691	706

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

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

Piedmont EMC - Duke Control Area

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PEAK (MW) (1)	106	108	110	113	115	118	120	123	125	128	131	133	136	139	142
ANNUAL ENERGY (GWh) (1)	132	135	138	141	144	147	150	154	157	160	163	167	170	173	177

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

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

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

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Requirements:															
PEAK (MW) (1)	33	34	34	35	36	37	38	38	39	40	41	42	43	43	44
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)	22	27	27	29	30	31	32	32	33	34	35	36	37	37	38
TOTAL RESOURCES (MW)	33	34	34	35	36	37	38	38	39	40	41	42	43	43	44
RESERVE CAPACITY (MW) (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL ENERGY (GWh) (1)	413	425	434	443	453	462	472	482	492	502	513	523	534	544	555

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

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PEAK (MW) (1)	139	142	145	148	151	154	158	161	164	168	172	175	179	182	186
ANNUAL ENERGY (GWh) (1)	545	560	572	585	597	609	622	636	649	662	676	690	704	718	732
ANNUAL ENERGY (GWh) (1) (Including Impact of Energy Efficiency Programs)	538	550	559	568	577	586	598	609	622	636	650	663	677	691	706

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

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

Rutherford EMC	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Requirements:															
PEAK (MW) (1)	280	283	287	291	295	299	303	307	311	316	320	325	329	334	339
Purchased Resources: (2)															
NCEMC WPSA	84	84	57	57	47	47	47	47	47	47	47	47	47	47	47
SEPA	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Duke Energy Purchases (3)	172	175	206	210	224	228	232	236	240	245	249	254	258	263	268
TOTAL RESOURCES (MW)	280	283	287	291	295	299	303	307	311	316	320	325	329	334	339
RESERVE CAPACITY (MW) (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL ENERGY (GWh) (4)	1,302	1,316	1,330	1,344	1,360	1,376	1,392	1,409	1,426	1,444	1,462	1,480	1,499	1,517	1,536

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

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

Rutherford EMC	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Requirements:															
PEAK (MW) (1)	317	321	325	329	334	338	343	347	352	357	362	368	373	378	384
Purchased Resources: (2)															
NCEMC WPSA	84	84	57	57	47	47	47	47	47	47	47	47	47	47	47
SEPA	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Duke Energy Purchases (3)	209	213	244	248	263	267	272	276	281	286	291	297	302	307	313
TOTAL RESOURCES (MW)	317	321	325	329	334	338	343	347	352	357	362	368	373	378	384
RESERVE CAPACITY (MW) (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL ENERGY (GWh) (4)	1,302	1,316	1,330	1,344	1,360	1,376	1,392	1,409	1,426	1,444	1,462	1,480	1,499	1,517	1,536

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

2010 ncuc IRP filings.xls
summer (Table 1.2)

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

EnergyUnited	LOCATION	FUEL SOURCE	CAPACITY DESIGNATION	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Requirements:																			
PEAK BEFORE ANTICIPATED ENERGY EFFICIENCY PROGRAMS (MW) (1)				545.5	547.6	551.2	555.3	561.2	567.4	574.0	580.9	587.6	595.6	603.8	611.8	619.8	628.1	636.3	644.5
Less: Impact of anticipated energy efficiency programs				(0.3)	(1.4)	(4.8)	(7.4)	(10.4)	(10.4)	(12.2)	(12.2)	(12.3)	(12.3)	(12.4)	(12.4)	(12.5)	(12.5)	(12.6)	(12.6)
PEAK NET OF ANTICIPATED ENERGY EFFICIENCY PROGRAMS				545.2	546.1	546.4	547.9	550.8	556.9	561.8	568.6	575.3	583.3	591.4	599.4	607.4	615.6	623.7	631.9
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	79
AEP Purchase	Duke Control Area	Coal	Base	28.0															
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	79.0
SEPA (streamflow renewable resource)	Southeast		Base/Peaking	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16
Iredell Transmission, LLC	Iredell County, NC	Methane Gas	Base	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Sun Edison Solar Project	Alexander County	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	3.0
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	56.2	377.1	377.4	429.9	432.8	456.9	461.8	468.6	475.3	482.3	490.4	498.4	506.4	514.6	522.7	530.9
TOTAL RESOURCES (MW)				545.2	546.1	546.4	547.9	550.8	556.9	561.8	568.6	575.3	583.3	591.4	599.4	607.4	615.6	623.7	631.9
RESERVE CAPACITY (MW) (4)			15% of EnergyUnited Peak	81.8	82.1	82.7	83.3	84.2	85.1	86.1	87.1	88.1	89.3	90.6	91.8	93.0	94.2	95.4	96.7
REPS Resources																			
ANNUAL ENERGY BEFORE ENERGY EFFICIENCY PROGRAMS(GWH) (5)				2,305.5	2,324.1	2,348.2	2,375.0	2,402.4	2,429.9	2,459.1	2,489.3	2,519.4	2,550.2	2,582.2	2,614.1	2,646.1	2,678.9	2,711.8	2,744.8
Less: Impact of anticipated energy efficiency programs				(0.8)	(2.0)	(45.1)	(69.9)	(98.4)	(98.6)	(113.8)	(114.2)	(114.5)	(115.0)	(115.4)	(115.6)	(116.2)	(116.7)	(117.1)	(117.5)
NET ANNUAL ENERGY				2,304.7	2,322.1	2,303.1	2,305.1	2,304.0	2,331.4	2,345.3	2,375.1	2,404.9	2,435.2	2,466.8	2,498.3	2,529.8	2,562.2	2,594.7	2,627.2
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	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	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	16.0
Other Anticipated Renewable Resources (TBD)	TBD	TBD				4.5	4.7	4.9	5.0	13.4	13.7	14.1	31.8	33.0	34.1	35.2	36.3	38.0	38.0
Total Anticipated Renewable Capacity				20.0	20.0	24.5	24.7	24.9	26.0	34.4	34.7	35.1	53.8	55.0	56.1	57.2	58.3	60.0	60.0
Energy from renewable resources (GWH):	REC's Carried Forward																		
Iredell Transmission LLC	31			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	25.0
Anticipated Solar Resources				0.6	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	3.9
SEPA	43			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	21.0
Nextera Wind REC's(Out of State)	150																		
Salem Energy Systems LLC REC's	58			30.0	30.0	30.0	30.0	30.0	30.0										
Other Renewable Resources/REC's needed											169.1	203.3	205.1	208.3	211.5	214.7	218.0	221.2	274.5
Total Anticipated Renewables				76.6	77.7	77.7	77.7	77.7	78.6	48.6	48.6	48.6	49.9	49.9	49.9	49.9	49.9	49.9	
Demand Side Management (6)																			
	# Customers	Demand Reduction(MW)	Hours in DSM																
DEMAND SIDE MANAGEMENT PROGRAMS:(activated during peak hours)																			
Residential Water Heaters	23,659	7.56	50 hours	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Coincident Peak Commercial/Industrial Consumers	30	8.83	50 hours	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Residential Air Conditioners	26,470	8.65	50 hours	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	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	25.0

2009 Peak- August 10th, 2009 HE 3:00pm ~510 MW
2010 Peak- ________ th, 2010 HE 0:00pm ~ ___ MW

1. Net Peak is EnergyUnited's peak net of load management measured at generation.
2. All purchases are 100% firm with reserves provided by the supplying entity.
3. The 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.

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

EnergyUnited	LOCATION	FUEL SOURCE	CAPACITY DESIGNATION	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Requirements:																			
PEAK BEFORE ENERGY EFFICIENCY PROGRAMS (MW) (1) (6)				568.8	569.7	592.7	596.9	603.1	609.3	616.1	623.2	630.5	637.5	645.1	652.8	660.1	667.7	675.4	683.9
Less: Impact of anticipated energy efficiency programs				(0.3)	(1.4)	(4.9)	(7.5)	(10.6)	(10.6)	(12.4)	(12.5)	(12.5)	(12.6)	(12.6)	(12.7)	(12.7)	(12.8)	(12.8)	(12.8)
PEAK NET OF ANTICIPATED ENERGY EFFICIENCY PROGRAMS				568.5	568.3	587.8	589.4	592.6	598.7	603.7	610.7	618.0	625.0	632.5	640.1	647.4	654.9	662.6	671.1
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	79
AEP Purchase	Duke Control Area	Coal	Base	28.0															
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	79.0
SEPA*(stream flow renewable)	Southeast		Base/Peaking	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16
Iredell Transmission, LLC	Iredell County, NC	Methane Gas	Base	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Sun Edison Solar Project	Alexander County	Solar	N/A		0.3	0.3	0.3	0.3	0.3	0.3	0.6	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9
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	100.5	420.0	419.5	472.1	475.3	500.4	505.4	512.1	519.4	526.1	533.6	541.2	548.5	556.0	563.7	572.2
TOTAL RESOURCES (MW)				568.5	568.3	587.8	589.4	592.6	598.7	603.7	610.7	618.0	625.0	632.5	640.1	647.4	654.9	662.6	671.1
RESERVE CAPACITY (MW) (4)			15% of Peak EU Load	88.3	88.5	88.9	89.5	90.5	91.4	92.4	93.5	94.6	95.6	96.8	97.9	99.0	100.1	101.3	102.6
REPS Resources																			
ANNUAL ENERGY BEFORE ENERGY EFFICIENCY PROGRAMS(GWH) (5)				#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####
Less: Impact of anticipated energy efficiency programs				(0.6)	(2.0)	(46.2)	(71.0)	(99.5)	(99.7)	(116.0)	(118.4)	(118.8)	(117.2)	(117.6)	(118.0)	(118.4)	(118.8)	(119.2)	(119.6)
NET ANNUAL ENERGY				#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####	#####
Capacity from renewable resources(MW):																			
Iredell Transmission, LLC	Iredell County, NC	Methane Gas	Base	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Anticipated Solar Resources	TBD	Solar	N/A		0.3	0.3	0.3	0.3	0.6	0.6	0.6	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9
SEPA	SouthEast		Intermediate/Peaking	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
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	38.0
Total Anticipated Renewable Capacity				19.0	19.3	23.8	24.0	24.2	24.6	33.0	33.3	33.7	51.8	52.9	54.0	55.1	56.2	57.9	57.9
Energy from renewable resources (GWH):	REC's Carried Forward																		
Iredell Transmission LLC	31			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	25.0
Anticipated Solar Resources				0.8	1.8	1.8	1.8	1.8	2.6	2.6	2.8	2.8	3.9	3.9	3.9	3.9	3.9	3.9	3.9
SEPA	43			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	21.0
Nextera Wind REC's(Out of State)	150																		
Salem Energy Systems LLC REC's	58			30.0	30.0	30.0	30.0	30.0	30.0										
Other Renewable Resources/REC's needed											189.1	203.3	205.1	208.3	211.5	214.7	218.0	221.2	274.5
Total Anticipated Renewables				76.8	77.7	77.7	77.7	77.7	76.8	48.6	48.6	48.6	49.9	49.9	49.9	49.9	49.9	49.9	
Demand Side Management																			
	# Customers	Demand Reduction	Hours in DSM																
DEMAND SIDE MANAGEMENT PROGRAMS: Activated during Peak Hours																			
Residential Water Heaters	23,658	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	3.6
Coincident Peak Commercial/Industrial Consumers	30	8.83	8 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	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	11.6
Annual Peak Demands(6)																			
2009 Peak-Jan 17th, 2009 HE 9:00am ~607 MW																			
2010 Peak-Jan 11th, 2010 HE 7:00am ~597 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 indial 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 (2010 Load Forecast)

Haywood EMC - Duke Control Area

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PEAK (MW) (1)	24	25	25	26	26	27	28	28	29	30	30	31	31	32	33
ANNUAL ENERGY (GWh) (1)	127	129	132	134	137	140	143	146	149	152	155	159	162	165	168

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

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

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

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Requirements:															
PEAK (MW) (1)	33	34	34	35	36	37	37	38	39	40	41	42	43	43	44
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)	16	18	18	19	19	20	20	21	22	23	28	31	34	36	37
TOTAL RESOURCES (MW)	33	34	34	35	36	37	37	38	39	40	41	42	43	43	44
RESERVE CAPACITY (MW) (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL ENERGY (GWh) (1)	196	200	204	208	213	217	222	226	231	236	241	246	251	256	261

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

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PEAK (MW) (1)	57	58	60	61	62	64	65	67	68	70	71	73	74	76	77
ANNUAL ENERGY (GWh) (1)	323	329	336	343	350	357	365	372	380	388	396	404	412	421	429
ANNUAL ENERGY (GWh) (1) (Including Impact of Energy Efficiency Programs)	321	327	333	340	346	353	361	368	376	384	392	400	408	417	425

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

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
EE Impacts from 2010 GreenCo Compliance Plan	1.57	2.08	2.58	3.08	3.58	3.83	4.04	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03

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

Haywood EMC - Duke Control Area

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PEAK (MW) (1)	31	32	33	33	34	35	36	36	37	38	39	40	41	41	42
ANNUAL ENERGY (GWh) (1)	127	129	132	134	137	140	143	146	149	152	155	159	162	165	168

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

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

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

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Load Requirements:															
PEAK (MW) (1)	50	51	52	54	55	56	57	59	60	61	62	64	65	66	68
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)	33	35	36	38	38	39	40	42	43	44	49	53	56	59	61
TOTAL RESOURCES (MW)	50	51	52	54	55	56	57	59	60	61	62	64	65	66	68
RESERVE CAPACITY (MW) (2)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL ENERGY (GWh) (1)	196	200	204	208	213	217	222	226	231	236	241	246	251	256	261

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

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PEAK (MW) (1)	82	83	85	87	89	91	93	95	97	99	101	103	106	108	110
ANNUAL ENERGY (GWh) (1)	323	329	336	343	350	357	365	372	380	388	396	404	412	421	429
ANNUAL ENERGY (GWh) (1) (Including Impact of Energy Efficiency Programs)	321	327	333	340	346	353	361	368	376	384	392	400	408	417	425

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

EE Impacts from 2010 GreenCo Compliance Plan	1.57	2.08	2.58	3.08	3.56	3.83	4.04	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03

North Carolina Electric IOU Service Area Map