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September 14, 2009

Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Attention: Michael R. Johnson, Director
Office of New Reactors

Subject: Duke Energy Carolinas, LLC
William States Lee III Nuclear Station Units 1 and 2
Docket Nos. 52-018 and 52-019
2009 Integrated Resource Plan
Ltr # WLG2009.09-02

Reference: Letter from B. J. Dolan (Duke Energy) to NRC Document Control Desk, *Duke Energy Carolinas 2008 Integrated Resource Plan*, dated November 04, 2008 (Ltr # WLG2008.11-02)

Duke Energy Carolinas (Duke) routinely provides a copy of the annual Integrated Resource Plan (IRP) to the NRC Staff for information in support of the Staff's review of the W. S. Lee III combined license (COL) application. Duke's 2008 IRP was transmitted to the Staff pursuant to the referenced letter In November 2008. On September 01, 2009, Duke submitted its 2009 IRP to the South Carolina Public Service Commission and the North Carolina Utilities Commission. A key purpose of the IRP is to provide management with information to assist in making the decisions necessary to ensure Duke has a reliable, diverse, environmentally sound, and reasonably-priced portfolio of resources as these resources are needed over time. The IRP model uses factors such as projected load growth, planned retirements of existing units, projected prices for fuel options, and projected impacts of greenhouse gas legislation to determine the optimal mix of existing and new generating assets going forward. The 2009 IRP, a copy of which is enclosed for your information, continues to demonstrate that new nuclear generation is the best option for meeting Duke's baseload generating needs in North and South Carolina.

The 2009 IRP indicates that, while nuclear generation is supported in virtually all planning scenarios, a commercial operation date (COD) of 2021 represents a lower-cost option for Duke ratepayers than the current COD of 2018. Taking this and other factors into account accordingly, Duke is amending its expected COD to reflect the later date.

A substantial portion of the NRC Staff's review of the Lee COL application has been completed. Further, regulatory certainty is one of several key considerations in making a final decision to build. Accordingly, Duke anticipates working with the Staff in the near

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term to assess the impact, if any, of a change in the COD on the application and the NRC's evaluations, with the expectation that the COL schedule will not be impacted significantly.

If you have any questions or need any additional information, please contact Peter Hastings, Nuclear Plant Development, Licensing Manager, at (980) 373-7820.

Bryan J. Dolan
Vice President
Nuclear Plant Development

Enclosure: Duke Energy Carolinas 2009 Integrated Resource Plan

AFFIDAVIT OF BRYAN J. DOLAN

Bryan J. Dolan, being duly sworn, states that he is Vice President, Nuclear Plant Development, Duke Energy Carolinas, LLC, that he is authorized on the part of said Company to sign and file with the U. S. Nuclear Regulatory Commission this supplement to the combined license application for the William States Lee III Nuclear Station and that all the matter and facts set forth herein are true and correct to the best of his knowledge.

Bryan J. Dolan

Bryan J. Dolan

Subscribed and sworn to me on September 14, 2009

K N Slays

Notary Public

My commission expires: April 19, 2010

SEAL

KIM M. SLAYS NOTARY PUBLIC NEW HANOVER COUNTY, N.C.

xc (w/o enclosure):

Gary Holahan, Deputy Director, Office of New Reactors
David Matthews, Director, Division of New Reactor Licensing
Scott Flanders, Director, Site and Environmental Reviews
Charles Ader, Director, Division of Safety Systems and Risk Assessment
Thomas Bergman, Deputy Division Director, DNRL
Glenn Tracy, Director, Division of Construction Inspection and Operational Programs
Luis Reyes, Regional Administrator, Region II
Loren Plisco, Deputy Regional Administrator, Region II
Stephanie Coffin, Branch Chief, DNRL

xc (w/enclosure):

Brian Hughes, Senior Project Manager, DNRL

The Duke Energy Carolinas Integrated Resource Plan (Annual Report)

September 1, 2009

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2009 Integrated Resource Plan – abbreviations	
Carbon Dioxide	CO2
Certificate of Public Convenience and Necessity	CPCN
Clean Air Interstate Rule	CAIR
Clean Air Mercury Rule	CAMR
Combined Construction and Operating License	COLA
Commercial Operation Date	COD
Compact Fluorescent	CFL
Demand Side Management	DSM
Direct Current	DC
Duke Energy Annual Plan	The Plan
Duke Energy Carolinas	DEC
Duke Energy Carolinas	The Company
Electric Membership Corporation	EMC
Electric Power Research Institute	EPRI
Energy Efficiency	EE
Environmental Protection Agency	EPA
Federal Energy Regulatory Commission	FERC
Federal Loan Guarantee	FLG
Flue Gas Desulphirization	FGD
Greenhouse Gas	GHG
Heating, Ventilation and Air Conditioning	HVAC
Integrated Gasification Combined Cycle	IGCC
Integrated Resource Plan	IRP
Load, Capacity, and Reserve Margin Table	LCR Table
Maximum Achievable Control Technology	MACT
Nantahala Power & Light	NP&L
NC Department of Environment and Natural Resources	NCDENR
NC Green Power	NCGP
NERC North American Electric Reliability Corp	NERC
New Source Performance Standard	NSPS
Nitrogen Oxide	NOx
North Carolina Division of Air Quality	NCDAQ
North Carolina Electric Membership Corporation	NCEMC
North Carolina Municipal Power Agency #1	NCMPA1
North Carolina Utility Commission	NCUC
Nuclear Regulatory Commission	NRC
Palmetto Clean Energy	PaCE
Photovoltaic	PV
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Present Value Revenue Requirements	PVRR
Production Tax Credit	PTC
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Renewable Energy and Energy Efficiency Portfolio Standard	REPS
Renewable Energy Certificates	REC
Renewable Portfolio Standard	RPS
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Saluda River Electric Cooperative	SR
Selective Catalytic Reduction	SCR
State Implementation Plan	SIP
Sulfur Dioxide	SO2
Technology Assessment Guide	TAG
Total Resource Cost	TRC
US Department of Energy	USDOE
Utility Cost Test	UCT
Virginia/Carolinas	VACAR
Western Carolina University	WCU

FORWARD

The Duke Energy Carolinas 2008 Integrated Resource Plan (IRP) (Docket No. E-100, Sub 118), filed November 3, 2008 and updated April 29, 2009 was the first biennial report under the revised Commission Rule R8-60.

Commission Rule R8-60 Appendix A subparagraph (h) (2) requires by September 1 of each year in which a biennial report is not required to be filed, an annual report to be filed with the Commission containing an updated 15-year forecast of the items described in R8-60 subparagraph (c) (1), as well as significant amendments or revision to the most recently filed biennial report, including amendments or revisions to the type and size of resources identified, as applicable. The following updates to the 2008 IRP are provided in the Duke Energy Carolinas 2009 IRP Annual Report.

a) 15-year forecast
b) Short term action plan
c) Escalation rates for resource options
d) Existing Generation Plans in Service
e) Renewable Energy Initiatives
f) Energy Efficiency and Demand Side Management peak and energy impacts
g) Wholesale Power Sales Commitments
h) Legislative and Regulatory Issues
i) Fundamental fuel, energy, and emission allowance prices
j) Generating units projected to be retired
k) Load and Resource Balance
l) Changes to existing and future resources
m) Overall planning process conclusions incorporating a) through l) above

EXECUTIVE SUMMARY

Duke Energy Carolinas (Duke Energy Carolinas) or (the Company), a subsidiary of Duke Energy Corporation, utilizes an integrated resource planning approach to ensure that it can reliably and economically meet the electric energy needs of its customers well into the future. Duke Energy Carolinas considers a diverse range of resources including renewable, nuclear, coal, gas, energy efficiency (EE), and demand-side management (DSM)[1] resources. The end result is the Company's Integrated Resource Plan (IRP) or Annual Plan.

Consistent with the responsibility to meet customer energy needs in a reliable and economic manner, the Company's resource planning approach includes both quantitative analysis and qualitative considerations. Quantitative analysis provides insights on future risks and uncertainties associated with fuel prices, load growth rates, capital and operating costs, and other variables. Qualitative perspectives such as the importance of fuel diversity, the Company's environmental profile, the stage of technology deployment, and regional economic development are also important factors to consider as long-term decisions are made regarding new resources.

Company management uses all of these perspectives and analyses to ensure that Duke Energy Carolinas will meet near-term and long-term customer needs, while maintaining flexibility to adjust to evolving economic, environmental, and operating circumstances in the future. The environment for planning the Company's system continues to be the most dynamic in Duke Energy Carolinas' 100-year-plus history. As a result, the Company believes prudent planning for customer needs requires a plan that is robust under many possible future scenarios. At the same time, it is important to maintain a number of options to respond to many potential outcomes of major planning uncertainties (e.g., federal greenhouse gas emission legislation).

Planning Process Results

Duke Energy Carolinas' resource needs increase significantly over the 20-year planning horizon even after incorporating the impact of the current recession to forecasted load. The Buck and Dan River combined cycle units along with the EE and DSM programs will fulfill this need through 2015. However, even if the Company fully realizes its goals for EE and DSM, the resource need grows to approximately 5,500 MW[2] by 2029. This IRP outlines the Company's options and plan for meeting the long-term need. The factors that influence resource needs are:

- Future load growth projections;
- Reduction of available capacity and energy resources (for example, due to unit retirements and expiration of purchased power agreements); and
- A 17 percent target planning reserve margin over the 20-year horizon.

[1] Throughout this IRP, the term EE will denote conservation programs while the term DSM will denote Demand Response programs consistent with N.C. Gen. Stat. 62-133.8 and 133.9.
[2] This figure does not match the Load and Resource Balance values shown on pages 43 due to inclusion of the Buck and Dan River CC, old fleet CT retirements, additional unscrubbed coal retirements and EE & DSM.

A key purpose of the IRP is to provide management with information to aid in making the decisions necessary to ensure that Duke Energy Carolinas has a reliable, diverse, environmentally-sound, and reasonably-priced portfolio of resources as these resources are needed over time. In order to focus upon near term decisions that are required over the next year or two, the analysis focuses on the near-term resource needs (from the present until 2015) and the time frame in which new nuclear capacity could be in place. There is sufficient time in later IRPs to focus on specific peaking resources needed for the 2015-2020 timeframe.

As approved by the North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSC SC), Duke Energy Carolinas is conducting project development work to evaluate the addition of the proposed William States Lee, III Nuclear Station in Cherokee County, South Carolina. The analysis of new nuclear capacity contained in the IRP focuses on the impact of various uncertainties, such as load variations, nuclear capital costs, the impact of greenhouse gas legislation, fuel prices, and the availability of options such as federal loan guarantees that can help reduce the costs to customers for this greenhouse gas-emission free base load resource.

With regard to the timeframe for new nuclear capacity, the IRP analysis provided three key insights: 1) inclusion of new nuclear capacity in the Company's portfolio of resources results in lower costs to customers (in net present value of revenue requirements) than portfolios without new nuclear capacity; 2) a regional partnership approach, allowing Duke Energy Carolinas and other companies to own partial shares of new nuclear units, would provide additional benefits to customers, if such opportunities arise; and 3) a commercial operation date (COD) around 2021 for sole ownership of one or two nuclear units by Duke Energy Carolinas is lower cost for customers than a COD around 2018. In addition, to the quantitative analysis showing the advantages of a later COD, a later date allows time for the Company to further explore the development of a regional nuclear strategy and to pursue legislation needed to minimize the financing costs ultimately borne by customers. The Company will continue to pursue a Combined Construction and Operation License (COLA) from the NRC.

Both DSM and EE programs play important roles in the development of a balanced, cost-effective portfolio. Renewable generation alternatives are also necessary to meet North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) enacted in 2007. Energy savings resulting from EE programs may also be used in part to meet the REPS obligations. The Company has also prepared a REPS Compliance Plan as a part of its resource planning activities.

In light of these analyses, as well as the public policy debate on energy and environmental issues, Duke Energy Carolinas has developed a strategy to ensure that the Company can meet customers' energy needs reliably and economically. Importantly, Duke Energy Carolinas' strategic action plan for long-term resources maintains prudent flexibility in the face of these dynamics.

The Company's accomplishments in the past year and action to be taken in the next are summarized below:

- Continue to seek regulatory approval of the Company's energy efficiency plan which includes a greatly-expanded portfolio of demand-side management and energy efficiency programs, and continue on-going collaborative work to develop and implement additional EE and DSM products and services.
  - In the first quarter of 2009, Duke Energy Carolinas received approval to implement its proposed energy efficiency programs in North Carolina and South Carolina. In addition the Company reached agreement with several parties, to its North Carolina application for regulatory treatment of the financial aspects of its proposed energy efficiency and demand response programs. The NCUC recently conducted a hearing on the regulatory treatment of the Company's plans; the PSCSC will conduct such a hearing in the latter half of 2009.
- Continue construction of the 825 MW Cliffside 6 unit, with the objective of bringing this additional capacity on line by 2012 at the existing Cliffside Steam Station.
- License, permit, and begin construction of new combined-cycle/peaking generation.
  - Duke Energy Carolinas received the Certificates of Public Convenience and Necessity (CPCN) from the NCUC for 1,240 MW (total) of combined-cycle natural gas generation at the Buck Steam Station and the Dan River Steam Station in June 2008.
  - Buck combined cycle (CC) project: Since the filing of the 2008 IRP, the schedule for the Buck CC project has been updated to eliminate the proposed phase-in of the project from combustion turbine (CT) operation in 2011 prior to the CC phase. The current plan is for the Buck combined cycle to be operational by the end of 2011. Project implementation is underway and construction is expected to begin by the first quarter of 2010.
  - Dan River CC project: Since the filing of the 2008 IRP, which reflected the Dan River CC project available for the summer of 2012, the project schedule has been updated to reflect a commercial operation date by the end of 2012, due to the lower forecasted load. This IRP demonstrates the need for the project for system reliability and the opportunity to reduce project cost through project synergies with the Buck combined cycle project during this timeframe. Uncertainties such as load forecast and energy efficiency accomplishments; however, could impact the ultimate timing of the Dan River CC project will continue to be monitored and the schedule could be further adjusted. The air permit application for the project was submitted in October 2008, with the final permit expected to be received by the end of 2009. Major equipment has been purchased and is scheduled for delivery in 2010 and construction is scheduled to begin the first quarter of 2011.
- Continue to preserve the option to secure new nuclear generating capacity.
  - The Company filed an application with the NRC for a COLA in December 2007.
  - The NCUC and PSCSC approved the Company's request for approval of its decision to continue to incur nuclear project development costs.

- The Company will continue to pursue project development, appropriate recovery, and evaluation of optimal time to file the Certificate of Public Convenience and Necessity (CPCN) in S.C.
- The Company will pursue available federal, state and local tax incentives and favorable financing options at the federal and state level.
- The Company will assess opportunities to benefit from economies of scale in new resource decisions by considering the prospects for joint ownership and/or sales agreements.

- Continue the evaluation of market options for traditional and renewable generation and enter into contracts as appropriate.
  - PPAs have been signed with developers of solar PV, landfill gas, thermal resources. Additionally, renewable energy certificates (RECs) purchase agreements have been executed for, purchases of unbundled RECs from wind, solar PV, solar thermal and hydroelectric facilities.
  - Duke Energy Carolina's Distributed Generation Solar photovoltaic (PV) program received regulatory approval from the NCUC to install 10 MW (DC) of PV generation that will be sited on customers' property.
- Continue to monitor energy-related statutory and regulatory activities.

I. INTRODUCTION

Duke Energy Carolinas has an obligation to provide reliable and economic electric service to its customers in North Carolina and South Carolina. To meet this obligation, the Company conducted an integrated resource planning process that serves as the basis for its 2009 IRP.

Integrated resource planning is about charting a course for the future in an uncertain world. Arguably, the planning environment continues to be more dynamic than ever. A few of the key uncertainties include, but are not limited to:

- Load Forecasts: How elastic is the demand for electricity? Will environmental regulations such as greenhouse gas regulation result in higher costs of electricity and, thus, lower electricity usage? Can a highly successful energy efficiency program actually flatten or even reduce demand growth? At what pace will recovery from the current economic conditions affect the demand for electricity?
- Nuclear Generation: Is the region ready for a nuclear revival? What is the timeframe needed to license and build nuclear plants? What level of certainty can be established with respect to the capital costs of a new nuclear power plant?
- Greenhouse Gas Regulation: What type of greenhouse gas legislation will be passed? Will it be industry-specific or economy-wide? Will it be a "cap-and-trade" system? How will allowances be allocated? To what degree will carbon offsets be allowed?
- Renewable Energy: Will utilities be able to secure sufficient renewable resources to meet renewable portfolio standards? Will a federal standard be set? Will it have a "safety valve" price?
- Demand-Side Management and Energy Efficiency: Can DSM and EE deliver the anticipated capacity and energy savings reliably? Are customers ready to embrace energy efficiency? Will an investment in DSM and EE be treated equally with investments in a generating plant?
- Building Materials Availability and Cost: How long will the demand for building materials and equipment continue to be depressed and will there be significant price increases and lengthened delivery times when the economy rebounds? Is this an aberration or a long-term trend?
- Gas Prices: What is the future of natural gas prices and supply? Will enhanced natural gas recovery techniques open up new reserves in the United States?
- Coal Prices: What is the future of coal prices and supply? What impact will increased regulatory pressure on the coal mining industry have on availability and price?

Duke Energy Carolinas' resource planning process seeks to identify what actions the Company must take to ensure a safe, reliable, reasonably-priced supply of electricity for its customers regardless of how these uncertainties unfold. The planning process considers a wide range of assumptions and uncertainties and develops an action plan that preserves the options necessary to meet customers' needs. The process and resulting conclusions are discussed in this document.

II. DUKE ENERGY CAROLINAS CURRENT STATE

Overview

Duke Energy Carolinas provides electric service to an approximately 24,000-square-mile service area in central and western North Carolina and western South Carolina. In addition to retail sales to approximately 2.41 million customers, Duke Energy Carolinas also sells wholesale electricity to incorporated municipalities and to public and private utilities. Table 2.1 and Table 2.2 show recent historical values for the number of customers and sales of electricity by customer groupings.

Table 2.1
Retail Customers (1000s, by number billed)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Residential	1,669	1,710	1,758	1,782	1,814	1841	1,874	1,909	1,952	2,052
General Service	276	280	288	293	300	306	312	318	323	334
Industrial	9	8	8	8	8	8	8	7	7	7
Nantahala P&L	60	61	63	64	66	67	68	70	71	***
Other	10	10	11	11	11	12	13	13	13	14
Total	2,023	2,070	2,128	2,159	2,198	2,234	2,275	2,317	2,366	2,407
	(Number of customers is average of monthly figures)									
	***Nantahala P&L customer counts for 2008 are included in the class customer counts									

Table 2.2
Electricity Sales (GWH Sold - Years Ended December 31)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Electric Operations										
Residential	21,394	22,334	22,719	23,898	23,356	24,542	25,460	25,147	26,782	27,335
General Service	21,458	22,467	23,282	23,831	23,933	24,775	25,236	25,585	26,977	27,288
Industrial	29,767	29,632	26,784	26,141	24,645	25,085	25,361	24,396	23,829	22,634
Nantahala P&L	992	1,070	1,057	1,099	1,134	1,163	1,227	1,256	1,255	***
Other[a]	284	295	279	269	268	267	266	269	276	284
Total Retail Sales	73,895	75,797	74,121	75,238	73,336	75,832	77,550	76,653	79,119	77,541
Wholesale sales[b].	0,000	0,000	0,000	0,000	2,359	1,969	2,251	2,318	2,326	2,332
Total GWH Sold	73,895	75,797	74,121	75,238	75,695	77,801	79,801	78,971	81,445	79,873
	[a] Other = Municipal street lighting and traffic signals									
	[b] Wholesale sales include sales to NC and SC municipal customers, Western Carolina University, City of Highlands and the joint owners of the Catawba Nuclear Station (Catawba Owners). Short-term, non-firm wholesale sales subject to the Bulk Power Market sharing agreement are not included.									
	***Nantahala P&L sales for 2008 are included in the class sales									

Existing Generation Plants in Service

Duke Energy Carolinas' generation portfolio is a balanced mix of resources with different operating and fuel characteristics. This mix is designed to provide energy at the lowest reasonable cost to meet the Company's obligation to serve customers. Duke Energy Carolinas-owned generation, as well as purchased power, is evaluated on a real-time basis in order to select and dispatch the lowest-cost resources to meet system load requirements. In 2008, Duke Energy Carolinas' nuclear and coal-fired generating units met the vast majority of customer needs by providing 46.6% and 53%, respectively, of Duke Energy Carolinas' energy from generation. Hydroelectric and CT generation and economical purchases from the wholesale market supplied the remainder.

The tables below list the Duke Energy Carolinas plants in service in North Carolina and South Carolina with plant statistics, and the system's total generating capability.

Table 2.3
North Carolina [a,b,c,d,e]

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Allen	1	165.0	170.0	Belmont, N.C.	Conventional Coal
Allen	2	165.0	170.0	Belmont, N.C.	Conventional Coal
Allen	3	265.0	274.0	Belmont, N.C.	Conventional Coal
Allen	4	280.0	286.0	Belmont, N.C.	Conventional Coal
Allen	5	270.0	279.0	Belmont, N.C.	Conventional Coal
Allen Steam Station		**1145.0**	**1179.0**		
Belews Creek	1	1110.0	1135.0	Belews Creek, N.C.	Conventional Coal
Belews Creek	2	1110.0	1135.0	Belews Creek, N.C.	Conventional Coal
Belews Creek Steam Station		**2220.0**	**2270.0**		
Buck	3	75.0	76.0	Salisbury, N.C.	Conventional Coal
Buck	4	38.0	39.0	Salisbury, N.C.	Conventional Coal
Buck	5	128.0	131.0	Salisbury, N.C.	Conventional Coal
Buck	6	128.0	131.0	Salisbury, N.C.	Conventional Coal
Buck Steam Station		**369.0**	**377.0**		
Cliffside	1	38.0	39.0	Cliffside, N.C.	Conventional Coal
Cliffside	2	38.0	39.0	Cliffside, N.C.	Conventional Coal
Cliffside	3	61.0	62.0	Cliffside, N.C.	Conventional Coal
Cliffside	4	61.0	62.0	Cliffside, N.C.	Conventional Coal
Cliffside	5	562.0	568.0	Cliffside, N.C.	Conventional Coal
Cliffside Steam Station		**760.0**	**770.0**		
Dan River	1	67.0	69.0	Eden, N.C.	Conventional Coal
Dan River	2	67.0	69.0	Eden, N.C.	Conventional Coal
Dan River	3	142.0	145.0	Eden, N.C.	Conventional Coal
Dan River Steam Station		**276.0**	**283.0**		
Marshall	1	380.0	380.0	Terrell, N.C.	Conventional Coal
Marshall	2	380.0	380.0	Terrell, N.C.	Conventional Coal
Marshall	3	658.0	658.0	Terrell, N.C.	Conventional Coal
Marshall	4	660.0	660.0	Terrell, N.C.	Conventional Coal
Marshall Steam Station		**2078.0**	**2078.0**		
Riverbend	4	94.0	96.0	Mt. Holly, N.C.	Conventional Coal
Riverbend	5	94.0	96.0	Mt. Holly, N.C.	Conventional Coal
Riverbend	6	133.0	136.0	Mt. Holly, N.C.	Conventional Coal
Riverbend	7	133.0	136.0	Mt. Holly, N.C.	Conventional Coal
Riverbend Steam Station		**454.0**	**464.0**		
TOTAL N.C. CONVENTIONAL COAL		**7302.0 MW**	**7421.0 MW**		

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Buck	7C	25.0	30.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck	8C	25.0	30.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck	9C	12.0	15.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck Station CTs		**62.0**	**75.0**		
Dan River	4C	0.0	0.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River	5C	24.0	31.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River	6C	24.0	31.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River Station CTs		**48.0**	**62.0**		
Lincoln	1	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	2	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	3	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	4	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	5	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	6	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	7	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	8	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	9	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	10	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	11	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	12	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	13	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	14	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	15	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	16	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln Station CTs		**1267.2**	**1488.0**		

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Riverbend	8C	0.0	0.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	9C	22.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	10C	22.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	11C	20.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend Station CTs		**64.0**	**90.0**		
Rockingham	1	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	2	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	3	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	4	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	5	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham CTs		**825.0**	**825.0**		
TOTAL N.C. COMB. TURBINE		**2266.2 MW**	**2540.0 MW**		
McGuire	1	1100.0	1156.0	Huntersville, N.C.	Nuclear
McGuire	2	1100.0	1156.0	Huntersville, N.C.	Nuclear
McGuire Nuclear Station		**2200.0**	**2312.0**		
TOTAL N.C. NUCLEAR		**2200.0 MW**	**2312.0 MW**		
Bridgewater	1	11.5	11.5	Morganton, N.C.	Hydro
Bridgewater	2	11.5	11.5	Morganton, N.C.	Hydro
Bridgewater Hydro Station		**23.0**	**23.0**		
Bryson City	1	0.48	0.48	Whittier, N.C.	Hydro
Bryson City	1	0.5	0.5	Whittier, N.C.	Hydro
Bryson City Hydro Station		**0.98**	**0.98**		
Cowans Ford	1	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	2	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	3	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	4	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford Hydro Station		**325.2**	**325.2**		
Dillsboro	1	0.175	0.175	Dillsboro, N.C.	Hydro
Dillsboro	2	0.05	0.05	Dillsboro, N.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Dillsboro Hydro Station		**0.225**	**0.225**		
Lookout Shoals	1	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals	2	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals	3	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals Hydro Station		**27.9**	**27.9**		
Mountain Island	1	14	14	Mount Holly, N.C.	Hydro
Mountain Island	2	14	14	Mount Holly, N.C.	Hydro
Mountain Island	3	17	17	Mount Holly, N.C.	Hydro
Mountain Island	4	17	17	Mount Holly, N.C.	
Mountain Island Hydro Station		**62.0**	**62.0**		
Oxford	1	20.0	20.0	Conover, N.C.	Hydro
Oxford	2	20.0	20.0	Conover, N.C.	Hydro
Oxford Hydro Station		**40.0**	**40.0**		
Rhodhiss	1	9.5	9.5	Rhodhiss, N.C.	Hydro
Rhodhiss	2	11.5	11.5	Rhodhiss, N.C.	Hydro
Rhodhiss	3	9.0	9.0	Rhodhiss, N.C.	Hydro
Rhodhiss Hydro Station		**30.0**	**30.0**		
Tuxedo	1	3.2	3.2	Flat Rock, N.C.	Hydro
Tuxedo	2	3.2	3.2	Flat Rock, N.C.	Hydro
Tuxedo Hydro Station		**6.4**	**6.4**		
Bear Creek	1	9.45	9.45	Tuckasegee, N.C.	Hydro
Bear Creek Hydro Station		**9.45**	**9.45**		
Cedar Cliff	1	6.4	6.4	Tuckasegee, N.C.	Hydro
Cedar Cliff Hydro Station		**6.4**	**6.4**		
Franklin	1	0.5	0.5	Franklin, N.C.	Hydro
Franklin	2	0.5	0.5	Franklin, N.C.	Hydro
Franklin Hydro Station		**1.0**	**1.0**		
Mission	1	0.6	0.6	Murphy, N.C.	Hydro
Mission	2	0.6	0.6	Murphy, N.C.	Hydro
Mission	3	0.6	0.6	Murphy, N.C.	Hydro
Mission Hydro Station		**1.8**	**1.8**		
Nantahala	1	50.0	50.0	Topton, N.C.	Hydro
Nantahala Hydro Station		**50.0**	**50.0**		
Tennessee Creek	1	9.8	9.8	Tuckasegee, N.C.	Hydro
Tennessee Creek Hydro Station		**9.8**	**9.8**		
Thorpe	1	19.7	19.7	Tuckasegee, N.C.	Hydro
Thorpe Hydro Station		**19.7**	**19.7**		
Tuckasegee	1	2.5	2.5	Tuckasegee, N.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Tuckasegee Hydro Station		**2.5**	**2.5**		
Queens Creek	1	1.44	1.44	Topton, N.C.	Hydro
Queens Creek Hydro Station		**1.44**	**1.44**		
TOTAL N.C. HYDRO		**617.8 MW**	**617.8 MW**		
TOTAL N.C. CAPABILITY		**12,386.0 MW**	**12,890.8 MW**		

Table 2.4
South Carolina [a,b,c,d,e]

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Lee	1	100.0	100.0	Pelzer, S.C.	Conventional Coal
Lee	2	100.0	102.0	Pelzer, S.C.	Conventional Coal
Lee	3	170.0	170.0	Pelzer, S.C.	Conventional Coal
Lee Steam Station		**370.0**	**372.0**		
TOTAL S.C. CONVENTIONAL COAL		**370.0 MW**	**372.0 MW**		
Buzzard Roost	6C	22.0	22.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	7C	22.0	22.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	8C	22.0	22.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	9C	22.0	22.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	10C	18.0	18.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	11C	18.0	18.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	12C	18.0	18.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	13C	18.0	18.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	14C	18.0	18.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	15C	18.0	18.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost Station CTs		**196.0**	**196.0**		
Lee	7C	42.0	42.0	Pelzer, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Lee	8C	42.0	42.0	Pelzer, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Lee Station CTs		**84.0**	**84.0**		
Mill Creek	1	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	2	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	3	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	4	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	5	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Mill Creek	6	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	7	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	8	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek Station CTs		**595.4**	**739.2**		
TOTAL S.C. COMB TURBINE		**875.4 MW**	**1019.2 MW**		
Catawba	1	1129.0	1163.0	York, S.C.	Nuclear
Catawba	2	1129.0	1163.0	York, S.C.	Nuclear
Catawba Nuclear Station		**2258.0**	**2326.0**		
Oconee	1	846.0	865.0	Seneca, S.C.	Nuclear
Oconee	2	846.0	865.0	Seneca, S.C.	Nuclear
Oconee	3	846.0	865.0	Seneca, S.C.	Nuclear
Oconee Nuclear Station		**2538.0**	**2595.0**		
TOTAL S.C. NUCLEAR		**4796.0 MW**	**4921.0 MW**		
Jocassee	1	170.0	170.0	Salem, S.C.	Pumped Storage
Jocassee	2	170.0	170.0	Salem, S.C.	Pumped Storage
Jocassee	3	195.0	195.0	Salem, S.C.	Pumped Storage
Jocassee	4	195.0	195.0	Salem, S.C.	Pumped Storage
Jocassee Pumped Hydro Station		**730.0**	**730.0**		
Bad Creek	1	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	2	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	3	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	4	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek Pumped Hydro Station		**1360.0**	**1360.0**		
TOTAL PUMPED STORAGE		**2090.0 MW**	**2090.0 MW**		
Cedar Creek	1	15.0	15.0	Great Falls, S.C.	Hydro
Cedar Creek	2	15.0	15.0	Great Falls, S.C.	Hydro
Cedar Creek	3	15.0	15.0	Great Falls, S.C.	Hydro
Cedar Creek Hydro Station		**45.0**	**45.0**		
Dearborn	1	14.0	14.0	Great Falls, S.C.	Hydro
Dearborn	2	14.0	14.0	Great Falls, S.C.	Hydro
Dearborn	3	14.0	14.0	Great Falls, S.C.	Hydro
Dearborn Hydro Station		**42.0**	**42.0**		
Fishing Creek	1	11.0	11.0	Great Falls, S.C.	Hydro
Fishing Creek	2	9.5	9.5	Great Falls, S.C.	Hydro
Fishing Creek	3	9.5	9.5	Great Falls, S.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Fishing Creek	4	11.0	11.0	Great Falls, S.C.	Hydro
Fishing Creek	5	8.0	8.0	Great Falls, S.C.	Hydro
Fishing Creek Hydro Station		**49.0**	**49.0**		
Gaston Shoals	3	1.0	1.0	Blacksburg, S.C.	Hydro
Gaston Shoals	4	1.0	1.0	Blacksburg, S.C.	Hydro
Gaston Shoals	5	1.0	1.0	Blacksburg, S.C.	Hydro
Gaston Shoals	6	1.7	1.7	Blacksburg, S.C.	Hydro
Gaston Shoals Hydro Station		**4.7**	**4.7**		
Great Falls	1	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	2	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	3	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	4	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	5	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	6	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	7	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	8	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls Hydro Station		**24.0**	**24.0**		
Rocky Creek	1	2.9	2.9	Great Falls, S.C.	Hydro
Rocky Creek	2	2.9	2.9	Great Falls, S.C.	Hydro
Rocky Creek	3	2.9	2.9	Great Falls, S.C.	Hydro
Rocky Creek	4	2.9	2.9	Great Falls, S.C.	Hydro
Rocky Creek	5	4.8	4.8	Great Falls, S.C.	Hydro
Rocky Creek	6	4.8	4.8	Great Falls, S.C.	Hydro
Rocky Creek	7	2.9	2.9	Great Falls, S.C.	Hydro
Rocky Creek	8	2.9	2.9	Great Falls, S.C.	Hydro
Rocky Creek Hydro Station		**27.0**	**27.0**		
Wateree	1	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	2	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	3	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	4	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	5	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree Hydro Station		**85.0**	**85.0**		
Wylie	1	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie	2	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie	3	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie	4	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie Hydro Station		**72.0**	**72.0**		
99 Islands	1	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	2	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	3	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	4	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	5	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	6	1.6	1.6	Blacksburg, S.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
99 Islands Hydro Station		**9.6**	**9.6**		
Keowee	1	76.0	76.0	Seneca, S.C.	Hydro
Keowee	2	76.0	76.0	Seneca, S.C.	Hydro
Keowee Hydro Station		**152.0**	**152.0**		
TOTAL S.C. HYDRO		**510.3 MW**	**510.3 MW**		
TOTAL S.C. CAPABILITY		**8641.7 MW**	**8912.5 MW**		

Table 2.5
Total Generation Capability [a,b,c,d,e]

NAME	SUMMER CAPACITY MW	WINTER CAPACITY MW
TOTAL DUKE ENERGY CAROLINAS GENERATING CAPABILITY	**21,027.7**	**21,803.3**

Note a: Unit information is provided by state, but resources are dispatched on a system-wide basis.

Note b: Summer and winter capability does not take into account reductions due to future environmental emission controls.

Note c: Summer and winter capability reflects system configuration as of September 1, 2009.

Note d: Catawba Units 1 and 2 capacity reflects 100% of the station's capability, and does not factor in the North Carolina Municipal Power Agency #1's (NCMPA#1) decision to sell or utilize its 832 MW retained ownership in Catawba.

Note e: The Catawba units' multiple owners and their effective ownership percentages are:

CATAWBA OWNER	PERCENT OF OWNERSHIP
Duke Energy Carolinas	19.246%
North Carolina Electric Membership Corporation (NCEMC)	30.754%
NCMPA#1	37.5%
Piedmont Municipal Power Agency (PMPA)	12.5%

Fuel Supply

Duke Energy Carolinas fuel usage consists primarily of coal and uranium. Oil and gas are currently used for peaking generation, but natural gas usage will expand when the Buck and Dan River Combined Cycle units are brought on-line.

In recent years, Duke Energy Carolinas has burned approximately 19 million tons of coal annually; however, due to the current recession, the expected burn for 2009 is approximately 15 million tons of coal, with the burn returning to levels of the recent past over the next two or three years. Coal is procured primarily from Central Appalachian coal mines and delivered by the Norfolk Southern and CSX Railroads. The Company continually assesses coal market conditions to determine the appropriate mix of contract and spot market purchases in order to reduce exposure to the risk of price fluctuations. The Company also evaluates its diversity of coal supply from sources throughout the United States as well as international sources.

Due to the current recession, Eastern U.S. coal market prices have dropped precipitously from the all-time highs experienced in 2008. Forward market prices for two years out are in the same range as those seen in 2006-2007. In the short term, there are no economic or supply drivers leading the Company to pursue coal quality and regional supply diversification. However, the Company's goal is to develop greater supply and transportation flexibility in order to leverage changing opportunities in the increasingly volatile domestic and international markets, so the Company continues to evaluate long term strategies to achieve this goal.

To provide fuel for Duke Energy Carolinas' nuclear fleet, the Company maintains a diversified portfolio of natural uranium and downstream services supply contracts (conversion, enrichment, and fabrication) from around the world. Duke Energy Carolinas relies on long-term contracts to cover the largest portion of its forward requirements in each of the four industrial stages of the nuclear fuel cycle. By staggering long-term contracts over time, the Company's purchase price for deliveries within a given year consists of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. Diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply.

As fuel with a low cost basis is used and lower-priced legacy contracts are replaced with contracts at higher market prices, nuclear fuel expense is expected to increase in the future. Although the costs of certain components of nuclear fuel are expected to increase in future years, nuclear fuel costs on a kWh basis will likely continue to be a fraction of the kWh cost of fossil fuel. Therefore, customers will continue to benefit from the Company's diverse generation mix and the strong performance of its nuclear fleet through lower fuel costs than would otherwise result absent the significant contribution of nuclear generation to meeting customers' demands.

Renewable Energy Initiatives

Duke Energy Carolinas continues to pursue its renewable energy strategy, which can be characterized as one of diversification. Specifically, Duke Energy Carolinas seeks to build its portfolio of renewable resources through a combination of the following: (1) development of renewable energy resources owned and/or operated by Duke Energy Carolinas; (2) power purchase agreements; and (3) purchases of unbundled RECs. Duke Energy Carolinas' approach to building this portfolio of renewable resources is guided by the requirements of the NC REPS law and the possibility of additional state or federal legislative requirements that would promote renewable energy specifically or otherwise promote reduction in greenhouse gas emissions.

With respect to owned renewable energy resources, Duke Energy received NCUC approval in 2009 for its Distributed Generation Solar PV program to build, own, and operate a total of 10 MW (DC) of solar PV projects on customer sites and/or Duke Energy owned property. Implementation of this program has begun, with the current expectation that construction of an initial phase of projects will begin prior to year-end 2009, and the program in its entirety is expected to be fully implemented by the end of 2010.

Additionally, Duke Energy has continued to explore the possibilities of generating renewable energy through either co-firing biomass at existing coal-fired stations or repowering coal-fired stations as dedicated biomass-fired power stations. Preliminary biomass fuel supply assessments have been completed for the supply sheds surrounding the Carolinas coal-fired stations. These assessments were based on forest inventory data and surveys of potential suppliers. While these assessments indicate biomass fuels are available, they are not market forecasts and do not consider the potential impacts of the emerging bio-energy and bio-fuels industries. The Company plans to commission market forecasts for selected supply sheds later this year.

Phase 1 studies have been completed for co-firing biomass at all Carolinas coal-fired stations and for repowering Dan River Unit 3 for 100% biomass. The co-firing study evaluated three co-firing options at each station (co-milling, separate injection, and gasification), while the repowering study evaluated both stoker and bubbling fluidized bed technologies with capacities ranging from 60 to 100 MW when additional turbine work was included. The Phase 1 studies were designed to provide high level cost estimates and to identify the most promising options that would then be evaluated further.

Phase 2 siting studies and/or engineering studies will be commissioned later in 2009 for the leading alternatives. These evaluations will involve more detailed operational analysis and cost estimates. A one-month test burn was planned for Buck in late July, but the start date was delayed due to on-going regulatory discussions with North Carolina Department of Environment and Natural Resources (NCDENR). A three month trial is planned for summer/fall at Lee Steam Station. Both tests will use the co-milling method of co-firing.

Also within the category of Duke Energy-owned renewable resources, the Company continues to operate one of the largest fleets of hydroelectric power stations in the nation. While much of the Company's existing fleet of hydro plants does not qualify under the NC REPS law, certain existing assets do qualify based on recent Commission rulings. Additionally, the Company continues to evaluate opportunities to add new hydro generation capacity to its fleet that would qualify as renewable under NC REPS.

With respect to Power Purchase Agreements and REC purchases, the Company has entered into multiple contractual agreements for renewable resources and continues to negotiate and pursue additional such agreements. In a broad sense, the Company considers renewable energy resources in four categories: solar, swine waste, poultry waste, and general renewables. This aligns with the NC REPS law which requires certain amounts of renewable energy to come from solar, swine waste, and poultry waste. With respect to these categories, the Company has entered into agreements pertaining to solar energy and general renewables, but has yet to enter into any agreements for swine waste or poultry waste resources. With respect to swine waste and poultry waste resources, the Company has expressed to the Commission in separate filings the challenges in meeting these requirements (most recently in a Joint Motion filed on August 14, 2009 under Docket E-100 Sub 113, which was a joint motion with Progress Energy Carolinas, Dominion North Carolina Power, North Carolina Electric Membership Corporation, North Carolina Eastern Municipal Power Agency and North Carolina Municipal Power Agency Number 1). Nonetheless, the Company remains committed to procuring or developing these renewable resources, provided they are available and it is in the public interest to do so. Further, the Company is in active dialogue with other electric suppliers in the state to collaboratively procure these resources, which are aggregate obligations of all electric suppliers under the NC REPS law. This collaborative effort is in response to the Commission's recent order which directed the electric suppliers to proceed in this manner.

With respect to solar resources and general renewable resources, the Company has entered into several power purchase agreements and unbundled REC purchases, including agreements for landfill gas, hydro, wind, solar PV, and solar thermal resources. Some of the REC purchase agreements have been executed under the Company's "standard offer" program which was first initiated in January of 2009 with the intent to offer a streamlined process for contracting for renewable resources with smaller producers. Others agreements have been entered into on a negotiated basis outside of the standard offer parameters. Some of these negotiated agreements include agreements to purchase unbundled RECs, from both in-state and out-of-state renewable energy resources. The Company has found that wind RECs on the national market are available at very cost-effective prices, and as such as chosen to make some purchases of these, as permitted under the NC REPS law.

Additionally, Duke Energy Carolinas continues to search for ways to bring additional forms of renewable energy online in the Carolinas. Specifically, the Company believes that wind energy could play a meaningful role in the Carolinas. Despite the scarcity of wind resources in much of the southeast, wind development could be technologically viable in certain locations; namely the Appalachian Mountains and the coastal/offshore regions. Additionally, there may be opportunities to promote small-scale wind technologies that are viable in lower wind speeds, or to transmit wind power into the

Carolinas from other states where the wind resource is more abundant. Each of these options has its own set of challenges, but the Company continues to actively explore ways to make these options viable for the Carolinas. And aside from wind energy, the Company also continues to explore other innovative manners of producing renewable energy from various biomass and biogas processes including alternative manners to satisfy the swine waste and poultry waste requirements.

The Company also continues to support numerous green power programs in the Carolinas. The North Carolina GreenPower (NCGP) Program and South Carolina's Palmetto Clean Energy (PaCE) Program are programs supporting renewable energy. Their mission is to encourage renewable generation development from resources such as solar, wind, hydro, and organic matter by enabling electric consumers of the Carolinas, businesses, organizations, and others to help offset the cost of higher cost green energy production. Duke Energy Carolinas supports NCGP and PaCE by facilitating voluntary customer contributions to the program through the use of our customer support center and billing system. Also, at the request of Duke Energy Carolinas, NCGP created a Carbon Offset Program for North Carolina and South Carolina customers interested in "canceling out" the carbon dioxide produced from their daily activities. The Carbon Offset program empowers customers who seek to offset their carbon dioxide emissions from today's energy intensive lifestyle.

Current Energy Efficiency and Demand-Side Management Programs

Duke Energy Carolinas uses EE and DSM programs to help manage customer demand in an efficient, cost-effective manner. These programs can vary greatly in their dispatch characteristics, size and duration of load response, certainty of load response, and frequency of customer participation. In general, programs include two primary categories: EE programs that reduce energy consumption (conservation programs) and DSM programs that reduce energy demand (demand-side management or demand response programs and certain rate structure programs).

Demand Response – Load Control Curtailment Programs

These programs can be dispatched by the utility and have the highest level of certainty. Once a customer agrees to participate in a demand response load control curtailment program, the Company controls the timing, frequency, and nature of the load response. Duke Energy Carolinas' current load control curtailment program is:

- PowerManager for cycling of air conditioners

In the near-term, customers in NC will remain on the previous vintage of load control program, Residential Air Conditioning Load Control. However, once the Company receives an order from the NCUC approving the regulatory treatment of energy efficiency, these customers will migrate to the PowerManager program over time.

Demand Response – Interruptible and Related Rate Structures

These programs rely either on the customer's ability to respond to a utility-initiated signal requesting curtailment or on rates with price signals that provide an economic incentive to reduce or shift load. Timing, frequency and nature of the load response depend on customers' voluntary actions. Duke Energy Carolinas' current interruptible and time of use curtailment programs include:

- Interruptible Power Service (North Carolina Only)
- Standby Generator Control (North Carolina Only)
- PowerShare – a non-residential curtailable program
    - PowerShare Mandatory
    - PowerShare Voluntary
    - PowerShare Generator

- Rates using price signals
    - Residential Time-of-Use (including a Residential Water Heating rate)
    - General Service and Industrial Optional Time-of-Use rates
    - Hourly Pricing for Incremental Load

On September 1, 2006, firm wholesale agreements became effective between Duke Energy Carolinas and three entities, Blue Ridge Electric Membership Cooperative, Piedmont Electric Membership Cooperative, and Rutherford Electric Membership Cooperative. These contracts added approximately 48 MW of demand response capability to Duke Energy Carolinas[3].

Energy Efficiency Programs
These programs are typically non-dispatchable, conservation-oriented education or incentive programs. Energy and capacity savings are achieved by changing customer behavior or through the installation of more energy-efficient equipment or structures. All effects of these existing programs are reflected in the customer load forecast. Duke Energy Carolinas' existing conservation programs include:

- Residential Energy Star® rates for new construction
- Non-Residential Energy Assessments
- Residential Energy Assessments
- Low Income Energy Efficiency and Weatherization Program
- Energy Efficiency Education Program for Schools
- Residential Smart $aver® Energy Efficient Products Program
- Smart $aver® for Non-Residential Customers

A description of each current program can be found in Appendix C.

The Company received approval in both North Carolina and South Carolina to implement the new programs listed above. The projected impacts from those programs are included in this year's assessment of generation needs.

[3] Those demand-response impacts are already included in the forecast of loads for these customers, so no additional demand response capability was modeled in the analysis for this IRP.

Wholesale Power Sales Commitments

Duke Energy Carolinas currently provides full requirements wholesale power sales to Western Carolina University (WCU), the city of Highlands, City of Concord, Town of Dallas, Forest City, Kings Mountain, Lockhart Power Company, Due West SC, and Prosperity, SC. The Company is also committed to serve the full power needs of three cooperatives (Blue Ridge Electric Membership Corporation (EMC), Piedmont EMC and Haywood EMC) and the supplemental needs of one other cooperative (Rutherford EMC). Blue Ridge EMC, Piedmont EMC and Rutherford EMC are also co-owners with Duke Energy Carolinas of the Catawba Nuclear Station. These customers' load requirements are included in the Duke Energy Carolinas load obligation (see Chart 3.1 and Cumulative Resource Additions to meet a 17 Percent Planning Reserve Margin).

In 2005, Duke Energy Carolinas and North Carolina Municipal Power Authority1 (NCMPA1) began a backstand agreement of up to 432 MW (depending on operation of the Catawba and McGuire facilities) that expired December 31, 2007, but has been extended through 2011.

In 2006, firm wholesale agreements became effective between Duke Energy Carolinas and three entities, Blue Ridge EMC, Piedmont EMC, and Rutherford EMC. Duke Energy Carolinas will supply their supplemental resource needs through 2021. This need grows to approximately 448 MW by 2011 and approximately 580 MW by 2021. The analyses in this IRP assumed that these contracts would be renewed or extended through the end of the planning horizon.

In addition, Duke Energy Carolinas has committed to provide backstand service for North Carolina EMC throughout the 20-year planning horizon up to the amount of their ownership entitlement in Catawba Nuclear Station. On October 1, 2008, the Saluda River (SR) ownership portion of Catawba ceased to be reflected in the forecast due to a sale of this interest to Duke Energy Carolinas and NCEMC, which resulted in the elimination of any obligation for Duke Energy Carolinas to plan for Saluda River's load. NCEMC purchased a portion of Saluda's share of Catawba which served to increase the NCEMC total backstand obligation.

Duke Energy Carolinas has entered into a firm shaped capacity sale with NCEMC that began on January 1, 2009, and expires on December 31, 2038. Initially, 72 MW is supplied on peak with the option to NCEMC to increase the peak purchase to 147 MW by 2020.

The table on the following page contains information concerning Duke Energy Carolinas' wholesale sales contracts.

WHOLESALE SALES CONTRACTS

Wholesale Customer	Contract Designation	Type	Contract Term	Commitment (MW)									
				2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
NC/SC Municipalities													
	Full	Native Load		284	286	288	290	288	289	291	292	294	296
City of Concord, NC	Requirements	Priority	December 31, 2018 with										
Town of Dallas, NC			annual renewals. Can be										
Town of Forest City, NC			terminated on one year										
Town of Kings Mountain, NC			notice by either party after										
Lockhart Power Company			current contract term.										
Town of Due West, SC													
Town of Prosperity, SC													
See Note 1													
NP&L Wholesale	Full	Native Load		0	13	14	14	15	15	16	17	17	18
Western Carolina University	Requirements	Priority	Annual renewals. Can be										
Town of Highlands, NC			terminated on one years										
			notice by either party.										
See Note 1													
Blue Ridge EMC	Full	Native Load	December 31, 2021	183	186	190	194	195	199	202	206	210	214
See Note 1	Requirements	Priority											
Piedmont EMC	Full	Native Load	December 31, 2021	85	87	88	90	91	92	94	96	97	99
See Note 1	Requirements	Priority											
Rutherford EMC	Partial	Native Load	December 31, 2021	62	62	170	174	202	205	219	224	228	233
See Note 1	Requirements	Priority											
Haywood EMC	Full	Native Load	December 31, 2021	21	22	22	22	23	23	23	24	24	24
See Note 1	Requirements	Priority											
			January 1, 2010 through										
Greenwood	Full	Native Load	December 31, 2018	0	52	52	52	52	52	53	53	53	54
See Note 1	Requirements	Priority											
NCEMC	Catawba	Native Load	Through Operating Life of	687	687	687	687	687	687	687	687	687	687
See Note 2	Contract	Priority/System	Catawba Nuclear Station and										
	Backstand	Firm	McGuire Nuclear Station										
NCMPA1	Generation	Native Load		73	73	73							
	Backstand	Priority	January 1, 2008 through										
			December 31, 2011										
			January 1, 2009 through										
NCEMC	Shaped Capacity	Native Load	December 31, 2038	72	72	97	97	97	97	97	122	122	122
	Sale	Priority											

Note 1: The analyses in this Annual Plan assumed that the contracts will be renewed or extended through the end of the planning horizon.

Note 2: The annual commitment shown is the ownership share of Catawba Nuclear Station and is included in the load forecast. Equivalent capacity is included as a portion of the Catawba Nuclear Station resource.

Wholesale Purchased Power Agreements

Duke Energy Carolinas has secured various purchased power contracts with power marketers and non-utility generators that are currently in effect or will begin over the next couple of years. In 2009, the overall summer capability of the purchased power contracts is approximately 742 MW. The capability in megawatts varies depending on the start times, duration, and capability of each contract. The majority of these contracts (459 MW) will expire at the end of 2010.

Planning Philosophy with regard to Purchased Power

Opportunities for the purchase of wholesale power from suppliers and marketers are an important resource option for meeting the electricity needs of Duke Energy Carolinas' retail and wholesale customers. Duke Energy Carolinas has been active in the wholesale purchased power market since 1996 and during that time has entered into contracts totaling 2500 MWs to meet customer needs. The use of supply side requests for proposal (RFPs) continues to be an essential component of Duke Energy Carolinas' resource procurement strategy. In particular, the purchased power agreements that the Company has entered into have allowed customers to enjoy the benefits of discounted market capacity prices and have provided flexibility in meeting target planning reserve margin requirements.

The Company's approach to resource selection is as follows:

The IRP process is used to identify the type, size, and timing of the resource need. In selecting the optimal resource plan, Duke Energy Carolinas begins with an optimization model that selects the resource mix that minimizes the present value of revenue requirements (PVRR) for a given set of assumptions. The levelized cost method used for generation options serves as a proxy for either self-build or long-term purchased power opportunities. From the optimization step, several diverse portfolios of resources are selected for further detailed production costing modeling and ultimate selection of a resource plan for the IRP.

Once a resource need is identified, the Company determines the options to satisfy that need and determines the near-term and long-term actions necessary to secure the resource. The options could include a self-build Duke Energy Carolinas-owned, a Duke Energy Carolinas-owned acquired resource (new or existing), or a purchased power resource. The Company consistently has issued RFPs for peaking and intermediate resource needs. For example, following the identification of peaking and intermediate resource needs, the Company issued a RFP in May 2007 for conventional intermediate and peaking resource proposals of up to 800 MW beginning in the 2009-2010 timeframe and up to 2000 additional MW beginning in the 2013 timeframe. Potential bidders could submit bids for purchased power or for the acquisition of existing or new facilities. Ten bidders submitted a total of forty-five bids spanning time periods of two to thirty years.

The bid evaluation considered price, operational flexibility, and location benefits. Ultimately, the Company determined that none of the proposed bids provided sufficient advantages to offset the multiple benefits of the proposed Buck and Dan River projects. The consideration of purchase power options was described in the Company's CPCN application for these facilities and addressed in testimony. The Commission issued the CPCNs for the Buck and Dan River projects in June 2008.

The Company also issued an RFP for renewable energy proposals in 2007. This RFP process produced proposals for approximately 1,900 megawatts of electricity from alternative sources from 26 different companies. The bids included wind, solar, biomass, biodiesel, landfill gas, hydro, and biogas projects. The Company entered into PPAs for a large solar project and several landfill gas facilities. In addition, the Company continues to receive unsolicited proposals for renewable purchased power resources and has entered into several PPAs as a result of unsolicited proposals.

The 2008 and 2009 IRP plans included over 3000 MWs of "New CT" capacity, in addition to existing and committed resources for the Cliffside Modernization project and Buck and Dan River combined cycle projects, as well as Lee Nuclear. The "New CT" resources reflect an identified need for peaking capacity that will be refined in future IRPs and could be met through self-build or purchased resources, or a mix.

Although Duke Energy Carolinas evaluates the competitive wholesale market for peaking and intermediate resources, the Company's purchased power philosophy does not currently include soliciting purchased power bids for baseload capacity. Duke Energy Carolinas views baseload capacity as fundamentally different from peaking and intermediate capacity. Currently, there are two key concerns regarding relying upon the wholesale market for baseload capacity. First, generation outside the control area could be subject to interruption due to transmission issues more so than generation within the control area. Second, supplier default could jeopardize the ability to provide reliable service. The Company therefore believes that Duke Energy Carolinas-owned baseload resources are the most reliable means for Duke Energy Carolinas to meet its service obligations in a cost-effective and reliable manner.

In addition, the Company examines unsolicited bids for purchased power or resource acquisitions and is alert to opportunities to purchase power or resources.

Legislative and Regulatory Issues

Duke Energy Carolinas, which is subject to the jurisdiction of federal agencies including the Federal Energy Regulatory Commission (FERC), Environmental Protection Agency (EPA), and the NRC, as well as state commissions and agencies, is potentially impacted by state and federal legislative and regulatory actions. This section provides a high-level description of several issues Duke Energy Carolinas is actively monitoring or engaged in that could potentially influence choices for new generation.

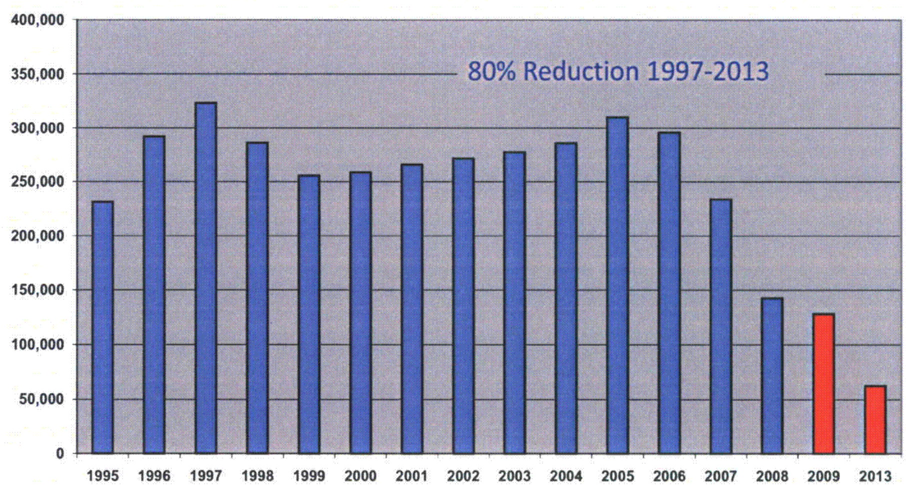
Air Quality

Duke Energy Carolinas is required to comply with numerous state and federal air emission regulations such as the Nitrogen Oxide (NOx) State Implementation Plan (SIP) Call ozone season NOx cap-and-trade program, the Acid Rain Program's annual sulfur dioxide (SO2) cap-and-trade program, and the 2002 North Carolina Clean Smokestacks Act.

As a result of complying with the North Carolina Clean Smokestacks Act, Duke Energy Carolinas will reduce (SO2) emissions by about 75 percent by 2013 from 2000 levels. The law also requires additional reductions in NOx emissions by 2007 and 2009, beyond those required by the federal NOx SIP Call, which Duke Energy Carolinas has and will achieve. This landmark legislation, which was passed by the North Carolina General Assembly in June of 2002, calls for some of the lowest state-mandated emission levels in the nation, and was passed with Duke Energy Carolinas' input and support.

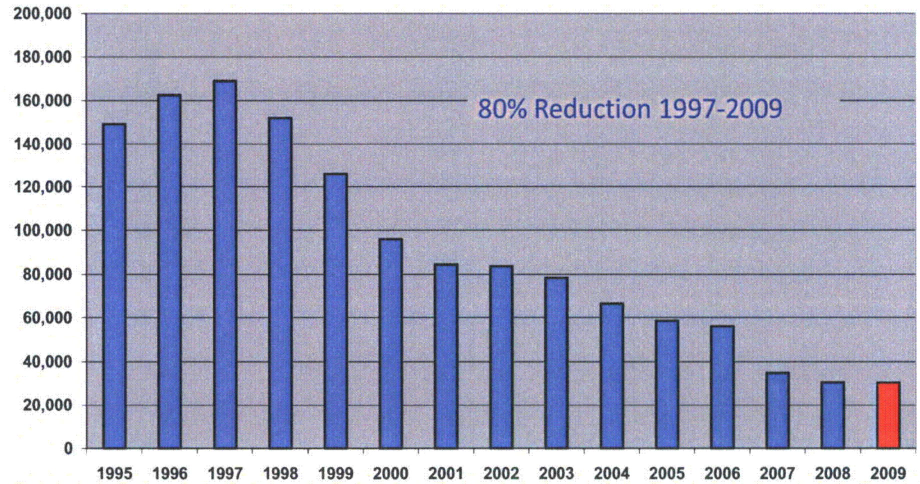
The following graphs show Duke Energy Carolinas' NOx and SO2 emissions reductions to comply with the federal NOx SIP Call and the 2002 North Carolina Clean Smokestacks Act.

Duke Energy Carolinas – Coal Fired Plants
Sulfur Dioxide Reductions (tons)



1

Duke Energy Carolinas – Coal Fired Plants
Nitrogen Oxides Reductions (tons)



2

Clean Air Interstate Rule (CAIR)

The EPA finalized its Clean Air Interstate Rule (CAIR) in May 2005. The CAIR limits total annual and summertime NO_x emissions and annual SO2 emissions from electric generating facilities across the Eastern U.S. through a two-phased cap-and-trade program. Phase 1 begins in 2009 for NO_x and in 2010 for SO_2. Phase 2 begins in 2015 for both NO_x and SO2. On July 11, 2008, the U.S. Court of Appeals for the District of Columbia (D.C. Circuit) issued its decision in *North Carolina v. EPA* vacating the CAIR. The EPA filed a petition for rehearing on September 24, 2008 with the D.C. Circuit asking the court to reconsider various parts of its ruling vacating the CAIR. In December 2008, the D.C. Circuit issued a decision remanding the CAIR to the EPA without vacatur. The EPA must now conduct a new rulemaking to modify the CAIR in accordance with the court's July 11, 2008 opinion. This decision means that the CAIR as initially finalized in 2005 remains in effect until the new EPA rule takes effect. The court did not impose a deadline or schedule on the EPA. It is uncertain how long the current CAIR will remain in effect or how the new rulemaking will alter the CAIR. Past and future developments related to the CAIR do not impact existing requirement that Duke Energy reduce its SO2 and NOx emissions under North Carolina Clean Smokestacks Act.

Federal Clean Air Mercury Rule (CAMR)

In May 2005, the EPA published the Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units for control of mercury, better known as the Clean Air Mercury Rule (CAMR). The rule established mercury emission-rate limits for new coal-fired steam generating units, as defined in Clean Air Act section 111(d). It also established a nationwide mercury cap-and-trade program covering existing and new coal-fired power units.

On February 8, 2008 the D.C. Circuit issued its opinion in New Jersey v. EPA, vacating the CAMR. Subsequent appeals of the court's decision were denied, meaning there is no longer a CAMR. The D.C. Circuit's decision vacating the CAMR creates uncertainty regarding future mercury emission reduction requirements and their timing. EPA has begun the process of developing a rule to replace the CAMR. The replacement rule is expected to establish maximum achievable control technology (MACT) emission limits for mercury. It is also possible that EPA could move to develop MACT emission limits for hazardous air pollutants other than mercury. EPA has not announced a schedule for this rulemaking, but it's likely to take several years to complete. Typically compliance with MACT limits is required three years after the limits are established.

Both North Carolina and South Carolina issued final CAMR rules in early 2007. North Carolina included in its 2007 rule a requirement that Duke Energy develop a mercury control plan for each coal fired unit in the state by 2013 and implement the plan by 2018. This regulation is not affected by the vacature of CAMR and will not be affected by whatever rule EPA develops as a replacement for CAMR. Based on current plans that include retirement of 1000 MW of older coal-fired capacity, Buck Units 5 & 6 are the only units in North Carolina that would be in operation in 2018 that do not have any plans for mercury control. All other units that will be in operation will have wet Flue Gas Desulphurization (FGD) systems with or without Selective Catalytic Reduction (SCR). A plan for mercury control for Buck will be developed by 2013. The NC regulation will allow offsetting the mercury control requirement at Buck by enhancing mercury control at another unit that has wet FGD.

8 Hour Ozone Standard

On March 12, 2008 EPA revised the 8 hour ozone standard by lowering it from 84 to 75 parts per billion. In March of 2009 the State of North Carolina submitted its recommendations for area designations for the 2008 standard. EPA is expected to take a year to finalize the recommendations at which time the state will have until March of 2013 to develop a SIP for compliance. Any additional controls that are required by the SIP would likely need to be in place prior to the 2015 ozone season. It is not known at this time if additional NOx controls will be required on Duke Energy Carolinas units.

Global Climate Change

At the federal level, the U. S. House of Representatives on June 26, 2009, passed H.R. 2454, the American Clean Energy and Security Act of 2009. The bill establishes a greenhouse gas (GHG) cap-and-trade program that includes the electric utility sector. Under H.R. 2454 the cap-and-trade program would start in 2012. The U.S. Senate has taken up debate of climate change legislation in several committees. The debate is expected to eventually reach the Senate floor but it is not known when that will occur. If the Senate eventually passes legislation that differs from the House version, there will be a conference to try and reconcile the House and Senate versions into a single bill that each would then have to pass before it becomes law. The GHG emissions from the Duke Energy Carolinas generating units will almost certainly be regulated under any federal GHG cap-and-trade program that is enacted.

The U.S. EPA, in response to a 2006 Supreme Court decision, issued an advanced notice of proposed rulemaking in July of 2008 seeking comment on alternative ways in which EPA could regulate GHG emissions under the Clean Air Act. In April of 2009 EPA issued a proposed Endangerment and Cause and Contribute Finding for Greenhouse Gases under the Clean Air Act. EPA could take final action on the proposal before the end of 2009. EPA's proposal specifically targets GHG emissions from new motor vehicles and new motor vehicle engines and if finalized would not regulate GHG emissions from electric generating facilities. It is possible that EPA could eventually regulate greenhouse gas emissions from the electric utility sector.

Renewable Portfolio Standard (RPS)

The North Carolina General Assembly enacted a Renewable Portfolio Standard (RPS) that requires specific actions by North Carolina utilities to acquire and incorporate set amounts and types of renewable energy in the supply portfolio as well as established cost caps for consumers.

In 2009 the U.S. Senate Committee on Energy and Natural Resources issued the American Clean Energy Leadership Act of 2009. The legislation includes a national renewable portfolio standard (RPS) provision that begins at 3% in 2011 and increase to 15% in 2021. It is expected that the Senate will attempt to combine this and climate change legislation into a single bill. In the House, the H.R. 2454 climate change bill passed on June 26, 2009 includes a federal renewable portfolio standard provision that begins at 6% in 2012 and increases to 20% in 2021. These two RPS proposals likely define the boundaries of the debate and the requirements of any potential federal RPS requirement that might be enacted.

III. RESOURCE NEEDS ASSESSMENT (FUTURE STATE)

To meet the future needs of Duke Energy Carolinas' customers, it is necessary to understand the load and resource balance. For each year of the planning horizon, Duke Energy Carolinas develops a load forecast of energy sales and peak demand. To determine total resources needed, the Company considers the load obligation plus a 17 percent target planning reserve margin. The capability of existing resources, including generating units, energy efficiency and demand-side management programs, and purchased power contracts, is measured against the total resource need. Any deficit in future years will be met by a mix of additional resources that reliably and cost-effectively meets the load obligation.

The following sections provide detail on the load forecast and the changes to existing resources.

Load Forecast

The Spring 2009 Forecast includes projections of the energy needs of new and existing customers in Duke Energy Carolinas service territory. Certain wholesale customers have the option of obtaining all or a portion of their future energy needs from other suppliers. While this may reduce Duke Energy Carolinas obligation to serve those customers, Duke Energy Carolinas assumes for planning purposes that certain existing wholesale customer load (excluding Catawba owner loads as discussed below) will remain part of the load obligation.

The forecasts for 2009 through 2029 include the energy needs of the wholesale and retail customer classes as follows:

- Duke Energy Carolinas retail, including the retail load associated with Nantahala Power and Light (NP&L) area
- Duke Energy Carolinas wholesale municipal customers served firm as native load.
- NP&L area wholesale customers Western Carolina University and the Town of Highlands
- NCEMC load relating to ownership of Catawba
- Blue Ridge, Piedmont and Rutherford Electric Membership Cooperatives' supplemental load requirements
- Hourly electricity sale to NCEMC starting in January 2009
- Haywood EMC load requirements starting in January 2009
- The city of Greenwood SC load requirements starting in January 2010
- Undesignated wholesale load of approximately 200 MWs in 2013, 400 MWs in 2014, 600 MWs in 2015 and 800 MWs in 2016 and beyond in recognition of potential wholesale load sales.

Notes (b), (d) and (e) of Table 3.2 give additional detail on how the four Catawba Joint Owners were considered in the forecasts. Per NCUC Rule R8-60 (i) (1) a description of the methods, models and assumptions used by the utility to prepare its peak load (MW) and energy sales (MWH) forecasts and the variables used in the models is provided on pages 4-6 of the Duke Energy Carolinas 2009 Forecast shown in Appendix B. Also, per Rule R8-60 (i) (1) (i) a forecast of customers by each customer class and a forecast of energy sales (KWH) by each customer class is provided on pages 9-14 and pages 19-23 of the 2009 Forecast Book. Also, the forecasts shown below in Tables 3.2 and 3.3 are not the same as those shown on pages 24-27 of the Duke Energy Carolinas Spring 2009 Forecast Book, primarily because the Spring 2009 Forecast Book's peak forecasts include the total resource needs for all Catawba Joint Owners. It also does not include the undesignated wholesale load used for planning purposes.

Duke Energy Carolinas retail sales have grown at an average annual rate of 1.1 percent from 1993 to 2008. (Retail sales, excluding line losses, are approximately 84 percent of the total energy considered in the 2009 IRP in 2009.) The following table shows historical and projected major customer class growth rates. The projected major customer class growth rates include the impacts of EE, carbon dioxide (CO2) price impact on demand, and plug-in hybrid vehicles but not wholesale sales.

Table 3.1
Retail Load Growth (kWh sales)

Time Period	Total Retail	Residential	General Service	Industrial Textile	Industrial Non-Textile
1993 to 2008	1.1%	2.1%	3.1%	-6.3%	0.7%
1993 to 2003	1.1%	1.9%	3.6%	-4.5%	0.5%
2003 to 2008	1.1%	2.7%	2.3%	-9.8%	1.0%
2008 to 2029	1.0%	1.5%	1.7%	-7.0%	0.1%

A decline in the Industrial Textile class was the key contributor to the low load growth from 2003 to 2008, offset by growth in the Residential and General Service classes over the same period. Over the last 5 years, an average of approximately 48,000 new residential customers per year was added to the Duke Energy Carolinas service area.

Duke Energy Carolinas' total retail load growth over the planning horizon is driven by the expected growth in Residential and General Service classes. Over the forecast horizon, the closing of Textile plants is expected to continue, especially in the near term as the US Bi-Lateral Trade Agreement with China has expired. The Other Industrial class is also expected to decline in the near turn due to the weak economy. In the long term several sectors, such as Rubber & Plastics and Food, are projected to show solid growth whereas other sectors, such as Furniture and Electronics, are projected to decline.

(Additional details on the current forecast can be found in the Duke Energy Carolinas Spring 2009 Forecast in Appendix B.)

The current 20-year forecast of the needs of the retail and wholesale customer classes, which does not include the impact of new energy efficiency programs, projects a 1.5 percent average annual growth in summer peak demand, while winter peaks are forecasted to grow at an average annual rate of 1.4 percent. The forecast for average annual territorial energy need is 1.6 percent. The growth rates use projected 2009 information as the base year with a 17,489 MW summer peak, a 15,997 MW winter peak and a 89,515 GWH average annual territorial energy need.

If the impacts of new energy efficiency programs are included, the average annual growth in summer peak demand is 1.4 percent, while winter peaks are forecasted to grow at an average annual rate of 1.3 percent. The forecast for average annual territorial energy need is 1.4 percent. The growth rates use projected 2009 information as the base year with a 17,479 MW summer peak, a 15,997 MW winter peak and an 89,442 GWH average annual territorial energy need.

A tabulation of the utility's forecasts for a 20- year period, including peak loads for summer and winter seasons of each year and annual energy forecasts is shown below. The load forecast for the 2009 IRP which includes the undesignated wholesale load but does not include new energy efficiency programs is shown below:

Table 3.2
Load Forecast without Energy Efficiency Programs

YEAR[a,b,c,d,e]	SUMMER (MW)[f]	WINTER (MW)[f]	TERRITORIAL ENERGY (GWH)[f]
2010	17,668	16,165	89,315
2011	17,995	16,433	90,427
2012	18,246	16,624	91,550
2013	18,450	16,820	91,946
2014	18,791	17,115	93,338
2015	19,198	17,449	95,118
2016	19,650	17,822	97,205
2017	19,867	17,986	98,194
2018	20,136	18,177	99,411
2019	20,405	18,380	100,776
2020	20,705	18,615	102,480
2021	21,009	18,849	104,311
2022	21,324	19,096	106,306
2023	21,658	19,360	108,511
2024	22,012	19,641	110,861
2025	22,363	19,922	113,277
2026	22,731	20,223	115,791
2027	23,092	20,511	118,227
2028	23,444	20,791	120,572
2029	23,787	21,065	122,802

The load forecast for the 2009 IRP which includes the undesignated wholesale load and also includes new energy efficiency programs, as reflected in Section 4, is shown below:

Table 3.3
Load Forecast with Energy Efficiency Programs

YEAR[a,b,c,d,e]	SUMMER (MW)[f]	WINTER (MW)[f]	TERRITORIAL ENERGY (GWH)[f]
2010	17,629	16,136	89,005
2011	17,923	16,362	89,843
2012	18,121	16,521	90,535
2013	18,287	16,643	90,629
2014	18,597	16,905	91,766
2015	18,962	17,195	93,200
2016	19,357	17,474	94,820
2017	19,531	17,642	95,581
2018	19,770	17,768	96,552
2019	20,011	17,942	97,565
2020	20,253	18,143	98,795
2021	20,526	18,250	100,494
2022	20,841	18,541	102,489
2023	21,175	18,805	104,694
2024	21,544	19,086	107,035
2025	21,895	19,411	109,460
2026	22,263	19,668	111,975
2027	22,609	19,912	114,411
2028	22,961	20,236	116,745
2029	23,304	20,510	118,985

Note a: The MW (demand) forecasts above are not the same as those shown on pages 24-27 of the Duke Energy Carolinas Spring 2009 Forecast Book, primarily because the Spring 2009 Forecast Book's peak forecasts include the total resource needs for all Catawba Joint Owners. It also does not include the undesignated wholesale load used for planning purposes.

Note b: As part of the joint ownership arrangement for Catawba Nuclear Station, NCEMC and SR took sole responsibility for their supplemental load requirements beginning January 1, 2001. As a result, SR's supplemental load requirements above its ownership interest in Catawba are not reflected in the forecast. Beginning in October 1, 2008, the SR ownership portion of Catawba is not reflected in the forecast due to a sale of this interest, which caused SR to become a full-requirements customer of another utility.

Note c: The load forecast includes Duke Energy Carolinas' contract to serve Blue Ridge, Piedmont and Rutherford EMC's supplemental load requirements from 2006 through 2028. A new contract between Duke Energy Carolinas and NCEMC provides additional hourly electricity sales to NCEMC beginning in January 2009.

Note d: As part of the joint ownership arrangement for the Catawba Nuclear Station, the NCMPA1 took sole responsibility for its supplemental load requirements beginning January 1, 2001. As a result, NCMPA1 supplemental load requirements above its ownership interest in Catawba Nuclear Station are not reflected in the forecast. In 2002, NCMPA1 entered into a firm-capacity sale beginning January 1, 2003, when it sold 400 MW of its ownership interest in

Catawba. In 2003, NCMPA1 entered into another agreement beginning January 2004, when it chose not to buy reserves for its remaining ownership interest (432 MW) from Duke Energy Carolinas. These changes reduce the Duke Energy Carolinas load forecast by the forecasted NCMPA1 load in the control area (974 MW at 2008 summer peak) and the available capacity to meet the load obligation by its Catawba ownership (832 MW). The Plan assumes that the reductions remain over the 20-year planning horizon.

Note e: The PMPA assumed sole responsibility for its supplemental load requirements beginning January 1, 2006. Therefore, PMPA supplemental load requirements above its ownership interest in Catawba Nuclear Station are not reflected in the load forecast beginning in 2006. Neither will the PMPA ownership interest in Catawba be included in the load forecast beginning in 2006, because PMPA also terminated its existing Interconnection Agreement with Duke Energy Carolinas effective January 1, 2006. Therefore, Duke Energy Carolinas is not responsible for providing reserves for the PMPA ownership interest in Catawba. These changes reduce the Duke Energy Carolinas load forecast by the forecasted PMPA load in the control area (503 MW at 2008 summer peak) and the available capacity to meet the load obligation by its Catawba ownership (277 MW). The Plan assumes that the reductions remain over the 20-year planning horizon.

Note f: Summer peak demand, winter peak demand and territorial energy are for the calendar years indicated. (The customer classes are described at the beginning of this section.) Territorial energy includes losses and unbilled sales (adjustments made to create calendar billed sales from billing period sales).

Changes to Existing Resources

Duke Energy Carolinas will adjust the capabilities of its resource mix over the 20-year planning horizon. Retirements of generating units, system capacity uprates and derates, purchased power contract expirations, and adjustments in EE and DSM capability affect the amount of resources Duke Energy Carolinas will have to meet its load obligation. Below are the known or anticipated changes and their impacts on the resource mix.

New Cliffside Pulverized Coal Unit
In March 2007, Duke Energy Carolinas received a CPCN for the 825 MW Cliffside 6 unit, which is scheduled to be on line in 2012. Duke Energy Carolinas received an air-quality permit from the North Carolina Division of Air Quality (NCDAQ) in January 2008. Construction began immediately following the issuance of the air permit and is underway.

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

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

Belews Creek Lower Pressure Rotor Upgrade
Capacity additions reflect an estimated 26 MW capacity up-rate at Belews Creek Steam Station due to increased efficiency from new low pressure turbine rotors on Units 1 and 2 to be installed in 2009 and 2010.

Buck Combined Cycle Natural Gas Unit
Economic factors in 2008 and 2009 have caused increased uncertainty with regard to forecasted load and near term capital expenditures. Due to the current recession impact on forecasted load there is not a need for additional capacity in the summer of 2011. Because of this the Buck combined cycle project will not be phased-in and will proceed straight to a combined cycle unit to be operational by the end of 2011 and available by the summer of 2012. Project implementation has begun to meet this operational date.

Dan River Combined Cycle Natural Gas Unit
The air permit application was submitted in October 2008, with the final permit expected to be received by the end of 2009. Major equipment is scheduled for delivery in 2010 and construction is scheduled to begin the first quarter of 2011. Since the filing of the 2008 IRP, which reflected the Dan River CC project available for the summer of 2012, the project schedule has been updated to reflect project availability by the summer of 2013, due to the lower forecasted load.

Although the reserve margin may be higher than the targeted 17% in 2013, this IRP reflects an operation date by the end of 2012 for a number of reasons, including:

- Over 1000 MWs of unrealized resources associated with renewables, EE and DSM, and capacity up-rates in the 2013 timeframe.
- The potential for quicker rebound of the economy than currently estimated in the load forecast.
- Maintains project synergies with the Buck combined cycle project.

With the planned retirement of over 1,600 MWs of cycling coal generation the Buck and Dan River combined cycle units will be needed to fill the Company's continued long term need for additional efficient cycling capability to maintain system reliability. Furthermore, significant environmental risks could result in additional retirements of cycling coal-fired generation thereby increasing the need for Dan River to be operational by the summer of 2015.

Multiple variables that could impact the ultimate timing of the Dan River combined cycle project will continued to be monitored.

Riverbend, Buck and Dan River Combustion Turbine De-rates
The available system capacity is reviewed every spring. In the 2009 review there were multiple de-rates among the old fleet combustion turbine fleet at Buck, Dan River and Riverbend totaling 124 MWs. These turbines were installed in the late 1960's and early 1970's and are approaching end of life, with increasing difficulty in finding parts required for optimal operation.

Short term capacity needs to maintain an acceptable reserve margin can be met with any combination of built or purchased generation, purchase power agreements, or increased DSM. In addition, the timing of the Dan River project can continue to be optimized.

Generating Units Projected To Be Retired

Various factors have an impact on decisions to retire existing generating units. These factors, including the investment requirements necessary to support ongoing operation of generation facilities, are continuously evaluated as future resource needs are considered. Table 3.4 reflects current assessments of generating units with identified decision dates for retirement or major refurbishment. There are two requirements related to the retirement of 800 MWs of older coal units. The first, a condition set forth in the NCUC Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6, requires the retirement of the existing Cliffside Units 1-4 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 the new EE and DSM programs up to the MW level added by the new Cliffside unit[4]. The requirement to retire older coal is also set forth in the air permit for the new Cliffside unit, in addition to Cliffside Units 1-4, of 350 MWs of coal generation by 2015, an additional 200 MWs by 2016, and an additional 250 MWs by 2018. If the North Carolina Utilities Commission determines that the scheduled retirement of any unit identified for retirement pursuant to the Plan will have a material adverse impact of the reliability of electric generating system, Duke may seek modification of the this plan. For planning purposes, the retirement dates for these 800 MWs of older coal are associated with the expected verification of realized EE load reductions, which is expected to occur earlier than the retirement dates set forth in the air permit.

Table 3.4 shows the assumptions used for planning purposes rather than firm commitments concerning the 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 Energy Carolinas will develop orderly retirement plans that consider the implementation, evaluation, and achievement of EE 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.

[4] Ref NCUC Docket No. E-7, Sub 790 Order Granting CPCN with Conditions, March 21, 2007

Table 3.4
Projected Unit Retirements

STATION	CAPACITY IN MW	LOCATION	DECISION DATE	PLANT TYPE
Buck 4*	38	Salisbury, N.C.	10/01/2011	Conventional Coal
Buck 3*	75	Salisbury, N.C.	10/01/2011	Conventional Coal
Cliffside 1*	38	Cliffside, N.C.	10/01/2011	Conventional Coal
Cliffside 2*	38	Cliffside, N.C.	10/01/2011	Conventional Coal
Cliffside 3*	61	Cliffside, N.C.	10/01/2011	Conventional Coal
Cliffside 4*	61	Cliffside, N.C.	10/01/2011	Conventional Coal
Dan River 1*	67	Eden, N.C.	10/01/2012	Conventional Coal
Dan River 2*	67	Eden, N.C.	10/01/2012	Conventional Coal
Dan River 3*	142	Eden, N.C.	10/01/2012	Conventional Coal
Buzzard Roost 6C**	22	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 7C**	22	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 8C**	22	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 9C**	22	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 10C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 11C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 12C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 13C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 14C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Buzzard Roost 15C**	18	Chappels, S.C.	6/01/2012	Combustion Turbine
Riverbend 8C**	0	Mt. Holly, N.C.	6/01/2012	Combustion Turbine
Riverbend 9C**	22	Mt. Holly, N.C.	6/01/2012	Combustion Turbine
Riverbend 10C**	22	Mt. Holly, N.C.	6/01/2012	Combustion Turbine
Riverbend 11C**	20	Mt. Holly, N.C.	6/01/2012	Combustion Turbine
Buck 7C**	25	Spencer, N.C.	6/01/2012	Combustion Turbine
Buck 8C**	25	Spencer, N.C.	6/01/2012	Combustion Turbine
Buck 9C**	12	Spencer, N.C.	6/01/2012	Combustion Turbine
Dan River 4C**	0	Eden, N.C.	6/01/2012	Combustion Turbine
Dan River 5C**	24	Eden, N.C.	6/01/2012	Combustion Turbine
Dan River 6C**	24	Eden, N.C.	6/01/2012	Combustion Turbine
Riverbend 4*	94	Mt. Holly, N.C.	6/01/2015	Conventional Coal
Riverbend 5*	94	Mt. Holly, N.C.	6/01/2015	Conventional Coal
Riverbend 6*	133	Mt. Holly, N.C.	6/01/2016	Conventional Coal
Riverbend 7*	133	Mt. Holly, N.C.	6/01/2017	Conventional Coal
Buck 5***	128	Spencer, N.C.	1/01/2020	Conventional Coal
Buck 6***	128	Spencer, N.C.	1/01/2020	Conventional Coal
Lee 1***	100	Pelzer, S.C.	1/01/2020	Conventional Coal
Lee 2***	100	Pelzer, S.C.	1/01/2020	Conventional Coal
Lee 3***	170	Pelzer, S.C.	1/01/2020	Conventional Coal

Notes:

* Retirement assumptions associated with the conditions in the NCUC Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6.

** The old fleet combustion turbines retirement dates were accelerated based on derates in 2009, availability of replacement parts and the general condition of the remaining units.

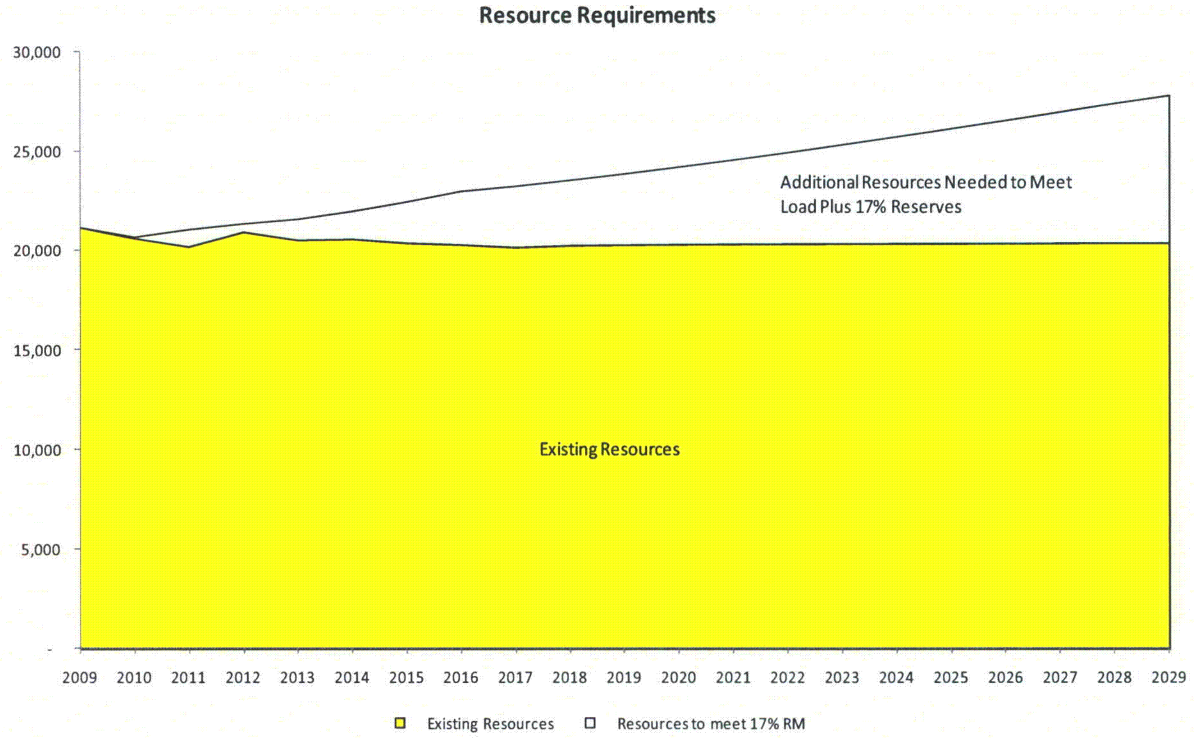
*** For the 2009 IRP process, remaining coal units without scrubbers were assumed to be retired in 2020. Based on the continued increased regulatory scrutiny from an air, water and waste perspective, these units will likely either be required to install additional controls or retire. If a decision is made to control any of these units, they will be removed from the retirement list.

Load and Resource Balance

The following chart shows the existing resources and resource requirements needed to meet the load obligation, plus the 17 percent target planning reserve margin. Beginning in 2009, existing resources, consisting of existing generation and purchased power to meet load requirements, total 21,157 MW. The load obligation plus the target planning reserve margin is 20,462 MW, indicating sufficient resources to meet Duke Energy Carolinas' obligation. The need for additional capacity grows over time due to load growth, unit capacity adjustments, unit retirements, existing DSM program reductions, and expirations of purchased-power contracts. The need grows to approximately 3,640 MW by 2019 and to 7,490 MW by 2029. Assumptions made in the development of this chart include:

1. Cliffside 6 is built by the summer of 2012 and included in Existing Resources
2. Coal retirements associated with Cliffside 6 Ruling and Permits are included
3. No conservation programs are included
4. Existing DSM programs end in 2009 and are not replaced
5. Buck/Dan River combined cycle facilities are not included in Existing Resources
6. Renewable capacity is built or purchased to meet the NC REPS
7. No retirements of old fleet CTs or Buck, Dan River and Lee Steam Stations are included

Chart 3.1
Load and Resource Balance



Cumulative Resource Additions To Meet A 17 Percent Planning Reserve Margin

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Resource Need	0	70	890	420	1,080	1,430	2,110	2,740	3,120	3,340	3,640

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Resource Need	3,960	4,280	4,640	5,030	5,450	5,840	6,270	6,670	7,080	7,490

IV. RESOURCE ALTERNATIVES TO MEET FUTURE ENERGY NEEDS

Many potential resource options are available to meet future energy needs. They range from expanding EE and DSM resources to adding new generation capacity and/or purchases (including renewables) to the Duke Energy Carolinas system.

Following are the generation (supply-side) technologies Duke Energy Carolinas considered in detail throughout the planning analysis:

Conventional Technologies (technologies in common use)
- Base Load – 800 MW supercritical pulverized coal units
- Base Load – Two 1,117 MW nuclear units (AP1000)
- Peaking/Intermediate – 632 MW natural gas combustion turbine facility comprised of four units
- Peaking/Intermediate – 620 MW natural gas combined cycle facility comprised of 2-on-1 units with inlet chilling and duct firing

Demonstrated Technologies (technologies with limited acceptance and not in widespread use):
- Base Load - 630 MW class IGCC

Renewable Technologies
- On Shore Wind (15% contribution to capacity on peak)
- Solar PV (50% contribution to capacity on peak)
- Biomass Firing
  - Woody Biomass Firing
  - Poultry Waste Firing
  - Hog Digester Biogas Firing
- Landfill Gas

A portion of the REPS requirements was also assumed to be provided by EE and DSM, co-firing biomass in some of Duke Energy Carolinas' existing units, and by purchasing Renewable Energy Certificates (RECS) from out of state, as allowed in the legislation.

EE and DSM programs that were considered in the planning process:

EE and DSM Program Screening

The Company uses the DSMore model to evaluate the costs, benefits, and risks of DSM and EE programs and measures. DSMore is a financial analysis tool designed to estimate the value of a DSM/EE measure at an hourly level across distributions of weather and/or energy costs or prices. By examining projected program performance and cost effectiveness over a wide variety of weather and cost conditions, the Company is in a better position to measure the risks and benefits of employing DSM/EE measures versus traditional generation capacity additions, and further, to ensure that DSM resources are compared to supply side resources on a level playing field.

The analysis of energy efficiency cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: Utility Cost Test (UCT), Rate Impact Measure (RIM) Test, Total Resource Cost (TRC) Test, Participant Test, and Societal Test. DSMore provides the results of those tests for any type of energy efficiency program (demand response and/or energy conservation).

The use of multiple tests can ensure the development of a reasonable set of DSM/EE programs, indicate the likelihood that customers will participate, and also protect against cross-subsidization.

Energy Efficiency and Demand-Side Management Programs

Duke Energy Carolinas has made a strong commitment to energy efficiency and demand-side management. Duke Energy Carolinas has proposed a new save-a-watt approach that fundamentally changes both the way these programs are perceived and the role of the Company in achieving results. The new approach recognizes EE and DSM as a reliable, valuable resource, that is, a "fifth fuel," that should be part of the portfolio available to meet customers' growing need for electricity along with coal, nuclear, natural gas, and renewable energy. The "fifth fuel" helps customers meet their energy needs with less electricity, less cost and less environmental impact. The Company will manage EE and DSM as a reliable "fifth fuel" and provide customers with universal access to these services and new technology. Duke Energy Carolinas has the expertise, infrastructure, and customer relationships to produce results and make it a significant part of its resource mix. Duke Energy Carolinas accepts the challenge to develop, implement, adjust as needed, and verify the results of innovative energy efficiency programs for the benefit of its customers.

The EE and DSM plan will be updated annually based on the performance of programs, market conditions, economics, consumer demand, and avoided costs.

- Duke Energy Carolinas has reached a settlement with the North Carolina Public Staff, Southern Alliance for Clean Energy, Environmental Defense Fund, Natural Resources Defense Council, and the Southern Environmental Law Center to its North Carolina application for regulatory treatment of the financial aspects of its proposed energy efficiency and demand response programs. Under this agreement, if approved by the North Carolina Utilities Commission, the Company will agree to an earnings cap on efficiency programs, increased energy efficiency impacts in years 3 and 4 of the program, and recovery of lost margins. Additionally, this agreement, along with the approval of save-a-watt in Ohio, forms the basis for the Company's proposal in South Carolina.

The Duke Energy Carolinas' proposed EE plan also complies with the requirement set forth in the Cliffside Unit 6 CPCN Order[5] to spend at least 1% of annual retail revenue

[5] Ref NCUC Docket No. E-7, Sub 790 Order Granting CPCN with Conditions, March 21, 2007.

requirement from the sale of electricity on future conservation and demand response programs each year, subject to appropriate regulatory treatment. The proposed settlement will increase the Company's potential EE impacts significantly over the coming years, as used in the analysis for this IRP. However, pursuing energy efficiency and demand-side management initiatives will not meet all our growing demands for electricity. The Company still envisions the need to build clean coal, nuclear, and gas generation as well as cost-effective renewable generation, but the save-a-watt approach could address approximately half the 2015 new resource need.

Table 4.1 provides the base case projected load impacts of the conservation and DSM or demand response portfolio of products and services through 2033. These were included in the base case IRP analysis. The projected load impacts from the conservation programs were based upon three bundles of the save-a watt portfolio of programs. This was accomplished by allowing a new bundle to enter every four years. The conservation impacts were assumed at 85% of the target impacts from the NC Settlement on the EE proposal. The projected load impacts from the DSM programs are based upon the continuing as well as the new demand response programs.

Table 4.2 provides a high case scenario which uses the full target impacts of the save-a-watt bundle of programs for the first five years and then increases the load impacts at 1% of retail sales every year after that until the load impacts reach the economic potential identified by the 2007 market potential study. [6]

[6] The load impacts in the high energy efficiency case have been reduced to account for the load reductions from the customer price response to the inclusion of higher projected electric rates for the cost of carbon compliance in the load forecast.

Table 4.1

Base Case Projected Load Impacts										
Conservation and Demand-Side Management Programs										
	Conservation Program Load Impacts				Demand-Side Management Program Impacts					Total
	MWH			MW	Summer Peak MW					Summer Peak
Year	Residential	Non-residential	Total	Total	IS	SG	Power Share	Power Manager	Total	MW Impacts
2009	59,710	13,972	73,682	10	282	92	219		593	603
2010	251,430	58,487	309,917	39	282	92	244	81	700	739
2011	470,897	113,657	584,555	72	282	92	246	210	831	903
2012	805,626	209,104	1,014,730	125	282	92	247	322	943	1,069
2013	1,042,262	275,088	1,317,350	164	282	92	248	322	944	1,108
2014	1,249,931	322,141	1,572,072	194	282	92	249	322	945	1,139
2015	1,523,586	395,542	1,919,128	236	282	92	250	322	946	1,182
2016	1,884,568	500,912	2,385,480	293	282	92	251	322	947	1,240
2017	2,064,230	548,881	2,613,110	336	282	92	253	322	949	1,286
2018	2,266,115	593,843	2,859,958	366	282	92	253	322	949	1,315
2019	2,542,551	668,247	3,210,799	394	282	92	254	322	950	1,345
2020	2,908,695	775,567	3,684,262	452	282	92	256	322	952	1,404
2021	3,009,326	807,214	3,816,540	483	282	92	256	322	952	1,436
2022	3,009,414	807,170	3,816,584	483	282	92	258	322	954	1,438
2023	3,009,438	807,186	3,816,624	483	282	92	259	322	955	1,439
2024	3,017,662	809,197	3,826,859	483	282	92	260	322	956	1,440
2025	3,009,337	807,189	3,816,525	483	282	92	261	322	957	1,441
2026	3,009,263	807,306	3,816,569	483	282	92	262	322	958	1,442
2027	3,009,326	807,214	3,816,540	483	282	92	263	322	959	1,443
2028	3,017,663	809,192	3,826,855	483	282	92	265	322	961	1,445
2029	3,009,254	807,179	3,816,433	483	282	92	265	322	961	1,445

Table 4.2

High Case Projected Load Impacts										
Conservation and Demand-Side Management Programs										
	Conservation Program Load Impacts				Demand-Side Management Program Impacts					Total
	MWH			MW	Summer Peak MW					Summer Peak
Year	Residential	Non-residential	Total	Total	IS	SG	Power Share	Power Manager	Total	MW Impacts
2009	59,710	13,972	73,682	10	282	92	219		593	603
2010	251,430	58,487	309,917	39	282	92	244	81	700	739
2011	553,997	133,714	687,711	85	282	92	246	210	831	916
2012	947,796	246,005	1,193,800	147	282	92	247	322	943	1,090
2013	1,042,262	275,088	1,317,350	163	282	92	248	322	944	1,107
2014	1,249,931	322,141	1,572,072	194	282	92	249	322	945	1,139
2015	1,665,930	432,496	2,098,426	258	282	92	250	322	946	1,204
2016	2,131,757	566,614	2,698,371	331	282	92	251	322	947	1,278
2017	2,606,557	693,086	3,299,643	425	282	92	253	322	949	1,374
2018	3,108,075	814,481	3,922,556	502	282	92	253	322	949	1,451
2019	3,673,343	965,448	4,638,791	570	282	92	254	322	950	1,520
2020	4,232,100	1,128,436	5,360,536	657	282	92	256	322	952	1,609
2021	4,993,526	1,339,451	6,332,978	802	282	92	256	322	952	1,754
2022	5,626,168	1,509,022	7,135,189	903	282	92	258	322	954	1,857
2023	6,282,821	1,685,166	7,967,988	1,009	282	92	259	322	955	1,964
2024	6,983,198	1,872,570	8,855,769	1,082	282	92	260	322	956	2,038
2025	7,659,793	2,054,571	9,714,364	1,191	282	92	261	322	957	2,148
2026	8,374,170	2,246,568	10,620,738	1,302	282	92	262	322	958	2,260
2027	9,105,731	2,442,499	11,548,230	1,462	282	92	263	322	959	2,421
2028	9,881,746	2,649,808	12,531,554	1,582	282	92	265	322	961	2,543
2029	10,616,011	2,847,556	13,463,567	1,704	282	92	265	322	961	2,665

V. OVERALL PLANNING PROCESS CONCLUSIONS

Duke Energy Carolinas' Resource Planning process provides a framework for the Company to access, analyze and implement a cost-effective approach to meet customers' growing energy needs reliably. In addition to assessing qualitative factors, a quantitative assessment was conducted using a simulation model.

A variety of sensitivities and scenarios were tested against a base set of inputs for various resource mixes, allowing the Company to better understand how potentially different future operating environments such as fuel commodity price changes, environmental emission mandates, and structural regulatory requirements can affect resource choices, and, ultimately, the cost of electricity to customers. (Appendix A provides a detailed description and results of the quantitative analyses).

The quantitative analyses suggest that a combination of additional baseload, intermediate and peaking generation, renewable resources, EE, and DSM programs is required over the next twenty years to meet customer demand reliably and cost-effectively.

The new pulverized coal units at Cliffside (Cliffside Unit 6) and the new combined cycle facilities at the Buck and Dan River Steam stations have received CPCNs from the NCUC and were incorporated in the base generation. In addition, Duke Energy Carolinas has included DSM/EE and renewable resources consistent with the Company's energy efficiency plan approved in North Carolina and to meet the REPS. Approximately 200 MWs of nuclear up-rates were demonstrated to be cost effective in the 2008 IRP and specific projects are being developed to be implemented in the 2012-2016 timeframe. While near-term, there are no significant additional capacity needs beyond these committed and planned additions, the Company has capacity needs in 2016 and beyond.

As approved by the North Carolina Utilities Commission and the Public Service Commission of South Carolina, Duke Energy Carolinas is conducting project development work to evaluate the addition of the proposed William States Lee, III Nuclear Station in Cherokee County, South Carolina. The analysis of new nuclear capacity contained in the IRP focuses on the impact of various uncertainties, such as load variations, nuclear capital costs, the impact of greenhouse gas legislation, fuel prices, and the availability of options such as federal loan guarantees that can help reduce the costs to customers for this greenhouse gas-emission free base load resource.

The IRP analysis included sensitivities on each of the uncertainties described below:

Load Variations: The base case load forecast incorporates the impact of the current recession, projected energy efficiency achievements, demand destruction associated with the implementation of carbon legislation, new wholesale sales opportunities and the impact associated with future plug-in hybrid vehicles. The high and low load forecast sensitivities were developed to reflect a 95% confidence interval.

Nuclear Capital Costs: The project escalation rate was lower than the rate included in the 2008 IRP to reflect the current market trends and projections. For sensitivities the nuclear capital cost was varied on the low end to reflect the impact of minimal project contingency and varied on the high side to reflect increased labor and material cost.

Greenhouse Gas Legislation: Based on the momentum in the United States Congress with regards to greenhouse gas legislation, a base case assumption for CO2 prices was selected based on the CO2 reductions associated with the Dingle/Boucher bill proposed in the fall of 2008. Variations in CO2 prices were made to reflect the impact of carbon offsets on allowance prices currently being debated in the Waxman/Markey Bill (HR 2454).

Fuel Prices: The base case gas and coal price projections were based on the Duke Energy's fundamental price forecasts, which are updated annually. A high cost fuel scenario was evaluated which reflects the impact increased demand on natural gas and regulatory challenges to the coal mining industry. The lower cost fuel scenario represents enhanced natural gas recovery methods that open up increased reserves in the United States and lower demand on coal.

Nuclear Financing Options: The 2008 IRP incorporated tax and financing savings for the nuclear options. The Energy Policy Act of 2005 included incentives for new nuclear generation including production tax credits (PTCs) and federal loan guarantees (FLGs). In addition, state and local incentives are available to support new nuclear development. Also, the impact of collecting construction financing costs prior to commercial operations, thereby lowering the ultimate cost to customers, was incorporated into the analysis. Such treatment is allowed in both North Carolina and South Carolina, but to different degrees. The nuclear cost, referenced as "traditional financing" in the 2009 Annual Plan, include state and local incentives, and the ability to obtain construction financing cost prior to commercial operation. PTCs were included as traditional financing for the portfolios with a nuclear commercial operating date (COD) of 2018-2019 but not for a COD of 2021-2023. The nuclear cost, referenced as "favorable financing" included both the PTCs and FLGs. The potential opportunities to take advantage of these incentives were evaluated as sensitivities because (1) there is uncertainty regarding the inclusion of PTCs due to the construction and operation timing requirements; and (2) the limited number of facilities that will qualify for FLGs. However, it is important to continue to include these benefits as sensitivities because there are currently proposals in the CO2 legislation being debated that could expand these programs.

The results of the quantitative and qualitative analyses suggest that a combination of additional baseload, intermediate, and peaking generation, renewable resources, and EE and DSM programs are required over the next 20 years. The near-term resource needs can be met with new EE and DSM programs, completing construction of the Buck, Dan River, and Cliffside Projects, as well as pursuing nuclear uprates and renewable resources.

With regard to the timeframe for new nuclear capacity, the IRP analysis provided three key insights: 1) inclusion of new nuclear capacity in the Company's portfolio of resources results in lower costs to customers (in net present value of revenue requirements) than portfolios without new nuclear capacity; 2) a regional partnership approach—allowing Duke Energy Carolinas and other companies to own partial shares of new nuclear units — would provide additional benefits to customers, if such opportunities arise; and 3) a COD around 2021 for sole ownership of one or two nuclear units by Duke Energy Carolinas is lower cost for customers than a COD around 2018. In addition to the quantitative analysis showing the advantages of a later COD, a later date allows time for the Company to further explore the development of a regional nuclear strategy and to pursue legislation needed to minimize the financing costs ultimately borne by customers. The Company will continue to pursue a COLA from the NRC.

To demonstrate that the Company is planning adequately for customers, a portfolio incorporating the impact of impending carbon legislation was selected for the purposes of preparing the Load, Capacity, and Reserve Margin Table (LCR Table).

This portfolio consisted of 3,350 MW[7] of new natural gas simple cycle capacity, 2,234 MW of new nuclear capacity, 961 MW of Demand-Side Management, 483MW of Energy Efficiency, and 458 MW of renewable resources was selected. The portfolio included the Cliffside Unit 6 and Buck and Dan River CC Projects.

However, significant challenges remain such as obtaining the necessary regulatory approvals to implement the demand-side, energy efficiency, and supply-side resources, finding sufficient cost-effective, reliable renewable resources to meet the standard, integrating renewables into the resource mix, and ensuring sufficient transmission capability for these resources. In light of the qualitative issues such as the importance of fuel diversity, the Company's environmental profile, the stage of technology deployment and regional economic development, Duke Energy Carolinas has developed a strategy to ensure that the Company can meet customers' energy needs reliably and economically while maintaining flexibility pertaining to long-term resource decisions. The Company's accomplishments in the past year and action to be taken in the next are summarized below:

- Continue to seek regulatory approval of the Company's energy efficiency plan which includes a greatly-expanded portfolio of DSM and EE programs, and continue on-going collaborative work to develop and implement additional EE and DSM products and services.
    - In the first quarter of 2009, Duke Energy Carolinas received approval to implement its proposed EE programs in North Carolina and South Carolina. In addition the Company reached agreement with several parties, to its North Carolina application for regulatory treatment of the financial aspects of its proposed energy efficiency and demand response programs. The NCUC recently conducted a hearing on the regulatory treatment of the Company's plans; the PSCSC will conduct such a hearing in the latter half of 2009.

[7] The ultimate sizes of any generating unit may change somewhat depending on the vendor selected.

- Continue construction of the 825 MW Cliffside 6 unit, with the objective of bringing this additional capacity on line by 2012 at the existing Cliffside Steam Station.
- License, permit, and begin construction of new combined-cycle/peaking generation.
  - ➢ Duke Energy Carolinas received the CPCN from the NCUC for 1,240 MW (total) of CC natural gas generation at the Buck Steam Station and the Dan River Steam Station in June 2008.
  - ➢ Buck CC project: Since the filing of the 2008 IRP, the schedule for the Buck CC project has been updated to eliminate the proposed phase-in of the project from CT operation in 2011 prior to the CC phase. The current plan is for the Buck CC to be operational by the end of 2011. Project implementation is underway and construction is expected to begin by the first quarter of 2010.
  - ➢ Dan River CC project: Since the filing of the 2008 IRP, which reflected the Dan River CC project available for the summer of 2012, the project schedule has been updated to reflect a commercial operation date by the end of 2012, due to the lower forecasted load. This IRP demonstrates the need for the project for system reliability and the opportunity to reduce project cost through project synergies with the Buck combined cycle project during this timeframe. Uncertainties such as load forecast and energy efficiency accomplishments; however, could impact the ultimate timing of the Dan River CC project will continue to be monitored and the schedule could be further adjusted. The air permit application for the project was submitted in October 2008, with the final permit expected to be received by the end of 2009. Major equipment has been purchased and is scheduled for delivery in 2010 and construction is scheduled to begin the first quarter of 2011.
- Continue to preserve the option to secure new nuclear generating capacity.
  - ➢ The Company filed an application with the NRC for a COLA in December 2007.
  - ➢ The NCUC and PSCSC approved the Company's request for approval of its decision to continue to incur nuclear project development costs.
  - ➢ The Company will continue to pursue project development, appropriate recovery, and evaluation of optimal time to file the CPCN in S.C.
  - ➢ The Company will pursue available federal, state and local tax incentives and favorable financing options at the federal and state level.
  - ➢ The Company will assess opportunities to benefit from economies of scale in new resource decisions by considering the prospects for joint ownership and/or sales agreements.
- Continue the evaluation of market options for traditional and renewable generation and enter into contracts as appropriate.
  - ➢ PPAs have been signed with developers of solar PV, landfill gas, thermal resources. Additionally, REC purchase agreements have been executed for, purchases of unbundled RECs from wind, solar PV, solar thermal and hydroelectric facilities.
  - ➢ Duke Energy Carolina's Distributed Generation Solar PV program

received regulatory approval from the NCUC to install 10 MW (DC) of PV generation that will be sited on customers' property.

- Continue to monitor energy-related statutory and regulatory activities.

The planning process must be dynamic and adaptable to changing conditions. While this plan is the most appropriate resource plan at this point in time, good business practice requires Duke Energy Carolinas to continue to study the options, and make adjustments as necessary and practical to reflect improved information and changing circumstances. Consequently, a good business planning analysis is truly an evolving process that can never be considered complete.

The seasonal projections of load, capacity, and reserves of the selected plan are provided in tabular form below.

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

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Load Forecast																				
1 Duke System Peak	17,668	17,995	18,246	18,450	18,791	19,198	19,650	19,867	20,136	20,405	20,705	21,009	21,324	21,658	22,012	22,363	22,731	23,092	23,444	23,787
Reductions to Load Forecast																				
2 New EE Programs	(39)	(72)	(125)	(163)	(194)	(236)	(293)	(336)	(366)	(394)	(452)	(483)	(483)	(483)	(483)	(483)	(483)	(483)	(483)	(483)
3 Adjusted Duke System Peak	**17,629**	**17,922**	**18,121**	**18,286**	**18,598**	**18,962**	**19,357**	**19,530**	**19,770**	**20,010**	**20,253**	**20,526**	**20,841**	**21,175**	**21,529**	**21,880**	**22,248**	**22,609**	**22,961**	**23,304**
Cumulative System Capacity																				
4 Generating Capacity	19,915	19,916	19,966	20,773	21,137	21,155	21,018	20,966	20,833	20,833	20,833	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207
5 Capacity Additions	13	50	1,464	665	18	51	81	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	(12)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	0	0	(657)	(300)	0	(188)	(133)	(133)	0	0	(626)	0	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	19,916	19,966	20,773	21,137	21,155	21,018	20,966	20,833	20,833	20,833	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207
Purchase Contracts																				
9 Cumulative Purchase Contracts	765	312	312	166	166	143	143	143	143	143	140	139	130	130	130	130	130	130	130	130
Sales Contracts																				
10 Catawba Owner Backstand	(73)	(121)	(47)	(47)																
11 Catawba Owner Load Following Agreement	(23)	(23)																		
12 Cumulative Future Resource Additions																				
Base Load	0	0	0	0	0	0	0	0	0	0	0	1,117	1,117	2,234	2,234	2,234	2,234	2,234	2,234	2,234
Peaking/Intermediate	0	0	0	0	0	0	632	632	1,264	1,264	1,896	1,896	1,896	1,896	1,896	1,896	1,896	2,528	3,160	3,350
Renewables	14	27	171	175	179	183	220	224	318	337	371	405	420	420	420	435	435	458	458	458
13 Cumulative Production Capacity	**20,599**	**20,161**	**21,209**	**21,431**	**21,499**	**21,344**	**21,960**	**21,832**	**22,558**	**22,577**	**22,614**	**23,764**	**23,770**	**24,887**	**24,887**	**24,902**	**24,902**	**25,556**	**26,188**	**26,378**
Reserves w/o Demand-Side Management																				
14 Generating Reserves	2,970	2,239	3,088	3,145	2,902	2,381	2,604	2,301	2,788	2,566	2,360	3,238	2,928	3,712	3,358	3,022	2,654	2,947	3,228	3,074
15 % Reserve Margin	**16.8%**	**12.5%**	**17.0%**	**17.2%**	**15.6%**	**12.6%**	**13.5%**	**11.8%**	**14.1%**	**12.8%**	**11.7%**	**15.8%**	**14.1%**	**17.5%**	**15.6%**	**13.8%**	**11.9%**	**13.0%**	**14.1%**	**13.2%**
16 % Capacity Margin	14.4%	11.1%	14.6%	14.7%	13.5%	11.2%	11.9%	10.5%	12.4%	11.4%	10.4%	13.6%	12.3%	14.9%	13.5%	12.1%	10.7%	11.5%	12.3%	11.7%
Demand-Side Management																				
17 Cumulative DSM Capacity	699	830	943	944	945	946	947	949	949	952	952	952	954	955	956	957	958	959	961	961
ACLC / IS / SG	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618
New DSM Program Projection	81	212	325	326	327	328	329	331	331	334	334	334	336	337	338	339	340	341	343	343
18 Cumulative Equivalent Capacity	21,298	20,991	22,152	22,375	22,444	22,290	22,907	22,781	23,507	23,529	23,566	24,716	24,724	25,842	25,843	25,859	25,860	26,515	27,149	27,339
Reserves w/ DSM																				
19 Generating Reserves	3,669	3,069	4,031	4,089	3,847	3,327	3,551	3,250	3,737	3,518	3,312	4,190	3,882	4,667	4,314	3,979	3,612	3,906	4,189	4,035
20 % Reserve Margin	**20.8%**	**17.1%**	**22.2%**	**22.4%**	**20.7%**	**17.5%**	**18.3%**	**16.6%**	**18.9%**	**17.6%**	**16.4%**	**20.4%**	**18.6%**	**22.0%**	**20.0%**	**18.2%**	**16.2%**	**17.3%**	**18.2%**	**17.3%**
21 % Capacity Margin	17.2%	14.6%	18.2%	18.3%	17.1%	14.9%	15.5%	14.3%	15.9%	15.0%	14.1%	17.0%	15.7%	18.1%	16.7%	15.4%	14.0%	14.7%	15.4%	14.8%

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

	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29
Load Forecast																				
1 Duke System Peak	16,165	16,433	16,624	16,820	17,115	17,449	17,822	17,986	18,177	18,380	18,615	18,849	19,096	19,360	19,641	19,922	20,223	20,511	20,791	21,065
Reductions to Load Forecast																				
2 New EE Programs	(29)	(71)	(103)	(177)	(210)	(254)	(348)	(344)	(409)	(438)	(472)	(599)	(555)	(555)	(555)	(555)	(555)	(555)	(555)	(555)
3 Adjusted Duke System Peak	**16,136**	**16,361**	**16,522**	**16,642**	**16,906**	**17,195**	**17,474**	**17,642**	**17,767**	**17,942**	**18,143**	**18,250**	**18,541**	**18,805**	**19,086**	**19,367**	**19,668**	**19,956**	**20,236**	**20,510**
Cumulative System Capacity																				
4 Generating Capacity	20,766	20,638	20,639	20,689	21,495	21,860	21,878	21,740	21,688	21,555	21,555	21,555	20,929	20,929	20,929	20,929	20,929	20,929	20,929	20,929
5 Capacity Additions	13	13	50	1,464	665	18	51	81	0	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	(141)	(12)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	0	0	0	(657)	(300)	0	(188)	(133)	(133)	0	0	(626)	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	20,638	20,639	20,689	21,495	21,860	21,878	21,740	21,688	21,555	21,555	21,555	20,929	20,929	20,929	20,929	20,929	20,929	20,929	20,929	20,929
Purchase Contracts																				
9 Cumulative Purchase Contracts	868	319	319	166	166	143	143	143	143	143	140	139	130	130	130	130	130	130	130	130
Sales Contracts																				
10 Catawba Owner Backstand	(73)	(121)	(47)	(47)																
11 Catawba Owner Load Following Agreement	(23)	(23)																		
12 Cumulative Future Resource Additions																				
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	1,117	1,117	2,234	2,234	2,234	2,234	2,234	2,234
Peaking/Intermediate	0	0	0	0	0	0	0	632	632	1,264	1,264	1,896	1,896	1,896	1,896	1,896	1,896	1,896	2,528	3,160
Renewables	3	14	27	171	175	179	183	220	224	318	337	371	405	420	420	420	435	435	458	458
13 Cumulative Production Capacity	**21,413**	**20,829**	**20,988**	**21,785**	**22,200**	**22,199**	**22,066**	**22,683**	**22,554**	**23,280**	**23,296**	**23,335**	**24,477**	**24,492**	**25,609**	**25,609**	**25,624**	**25,624**	**26,279**	**26,911**
Reserves w/o Demand-Side Management																				
14 Generating Reserves	5,277	4,467	4,466	5,142	5,294	5,004	4,592	5,041	4,787	5,339	5,153	5,085	5,937	5,688	6,524	6,243	5,957	5,669	6,043	6,401
15 % Reserve Margin	**32.7%**	**27.3%**	**27.0%**	**30.9%**	**31.3%**	**29.1%**	**26.3%**	**28.6%**	**26.9%**	**29.8%**	**28.4%**	**27.9%**	**32.0%**	**30.2%**	**34.2%**	**32.2%**	**30.3%**	**28.4%**	**29.9%**	**31.2%**
16 % Capacity Margin	24.6%	21.4%	21.3%	23.6%	23.8%	22.5%	20.8%	22.2%	21.2%	22.9%	22.1%	21.8%	24.3%	23.2%	25.5%	24.4%	23.2%	22.1%	23.0%	23.8%
Demand-Side Management																				
17 Cumulative DSM Capacity	455	586	699	700	701	702	703	705	705	708	708	708	710	711	712	713	714	715	717	717
ACLC / IS / SG	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374
New DSM Program Projection	81	212	325	326	327	328	329	331	331	334	334	334	336	337	338	339	340	341	343	343
18 Cumulative Equivalent Capacity	21,868	21,415	21,687	22,485	22,901	22,901	22,769	23,388	23,259	23,988	24,004	24,043	25,187	25,203	26,321	26,322	26,338	26,339	26,996	27,628
Reserves w/ DSM																				
19 Generating Reserves	5,732	5,053	5,165	5,842	5,995	5,706	5,295	5,746	5,492	6,047	5,861	5,793	6,647	6,399	7,236	6,956	6,671	6,384	6,760	7,118
20 % Reserve Margin	**35.5%**	**30.9%**	**31.3%**	**35.1%**	**35.5%**	**33.2%**	**30.3%**	**32.6%**	**30.9%**	**33.7%**	**32.3%**	**31.7%**	**35.8%**	**34.0%**	**37.9%**	**35.9%**	**33.9%**	**32.0%**	**33.4%**	**34.7%**
21 % Capacity Margin	26.2%	23.6%	23.8%	26.0%	26.2%	24.9%	23.3%	24.6%	23.6%	25.2%	24.4%	24.1%	26.4%	25.4%	27.5%	26.4%	25.3%	24.2%	25.0%	25.8%

ASSUMPTIONS OF LOAD, CAPACITY, AND RESERVES TABLE

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

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

4. Generating Capacity must be online by June 1 to be included in the available capacity for the summer peak of that year. Capacity must be online by Dec 1 to be included in the available capacity for the winter peak of that year. Includes 103 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for NCMPA1 firm capacity sale.
   Generating Capacity also reflects a 277 MW reduction in Catawba Nuclear Station to account for PMPAs termination of their interconnection agreement with Duke Energy Carolinas.

5. Capacity Additions reflect an estimated 50 MW capacity uprate at the Jocassee pumped storage facility from increased efficiency from the new runners, a 36 MW increase in Belews Creek capacity due to LP rotor changeouts, and an 8.75 MW increase in capacity at Bridgewater Hydro by summer 2009.
   The 150 MW addition in Catawba Nuclear Station resulting from the Saluda River acquisition was completed in September of 2008. However, there was no change to Catawba's capacity due to this acquition. Saluda River's portion of load associated with Catawba has historically been modeled within Duke Energy's load projections. Therefore, Saluda's ownership in Catawba has also been included in the Existing Capacity for Load, Capacity and Reserves reporting.
   Capacity Additions include Duke Energy Carolinas projects that have been approved by the NCUC (Cliffside 6, Buck and Dan River Combined Cycle facilities).
   Also included is a 205 MW capacity increase due to nuclear uprates at Catawba, McGuire, and Oconee Timing of these uprates are shown from 2012-2016

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

7. The 657 MW capacity retirement in summer 2012 represents the projected retirement dates for Buck 3-4 (113 MW) Dan River 1 and 2 (134 MW), Cliffside units 1-4 (198 MW), and 346 MW of old fleet CTs.
   The 300 MW capacity retirement in summer 2013 represents the projected retirement date for Dan River Steam Station (276) and 24 MWs of old fleet CT retirements.
   The 188 MW capacity retirement in summer 2015 represents the projected retirement date for Riverbend 4 and 5.
   The 133 MW capacity retirement in summer 2016 represents the projected retirement date for Riverbend 6.
   The 133 MW capacity retirement in summer 2017 represents the projected retirement date for Riverbend 7.
   The 626 MW capacity retirement in summer 2017 represents the projected retirement date for Buck 5-6 (256 MW) and Lee Steam Station 1-3 (270 MW).
   The NRC has issued renewed energy facility operating licenses for all Duke Energy Carolinas' nuclear facilities.
   The Hydro facilities for which Duke has submitted an application to FERC for licence renewal are assumed to continue operation through the planning horizon.
   All retirement dates are subject to review on an ongoing basis.

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

9. Cumulative Purchase Contracts have several components:

   A. Piedmont Municipal Power Agency took sole responsibility for total load requirements beginning January 1, 2006. This reduces the SEPA allocation from 94 MW to 19 MW in 2006, which is attributed to certain wholesale customers who continue to be served by Duke.
   B. Purchased capacity from PURPA Qualifying Facilities includes the 88 MW Cherokee County Cogeneration Partners contract which began in June 1998 and expires June 2013 and miscellaneous other QF projects totaling 22 MW.
   C. Purchase of 151 MW from Rowan Unit 2 began January 1, 2006 and expires December 31, 2010.
   D. Purchase of 153 MW from Rowan Unit 1 began June 1, 2007 and expires December 31, 2010.
   E. Purchase of 153 MW from Rowan Unit 3 began June 1, 2008 and expires December 31, 2010.

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

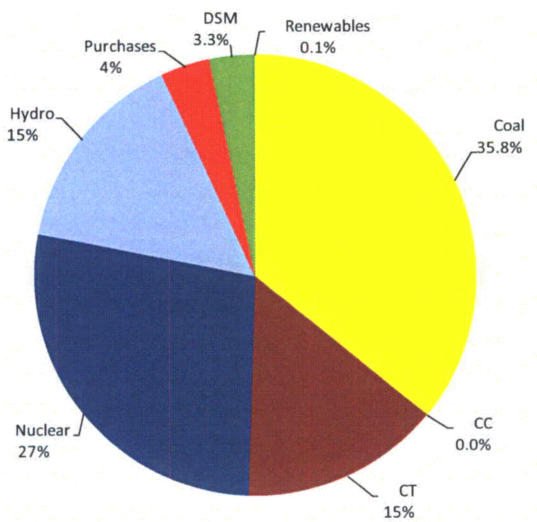
15. Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand

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

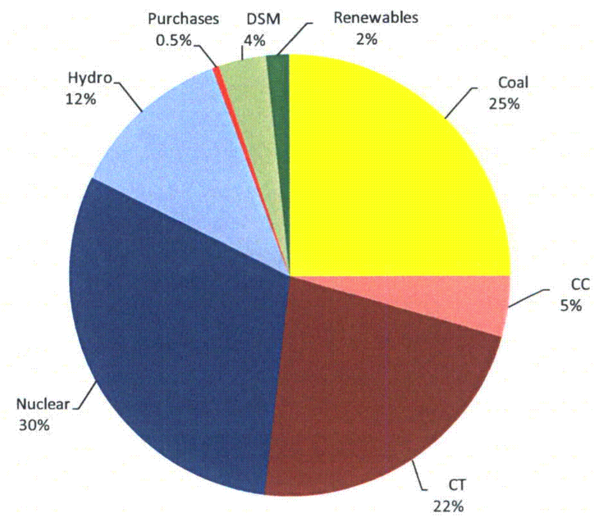
17. The Cumulative Demand Side Management capacity includes new Demand Side Management capacity representing placeholders for demand response and energy efficiency programs.

The charts below show the changes in Duke Energy Carolinas' capacity mix and energy mix between 2010 and 2029. The relative shares of renewables, energy efficiency, and gas all increase, while the relative share of coal decreases.

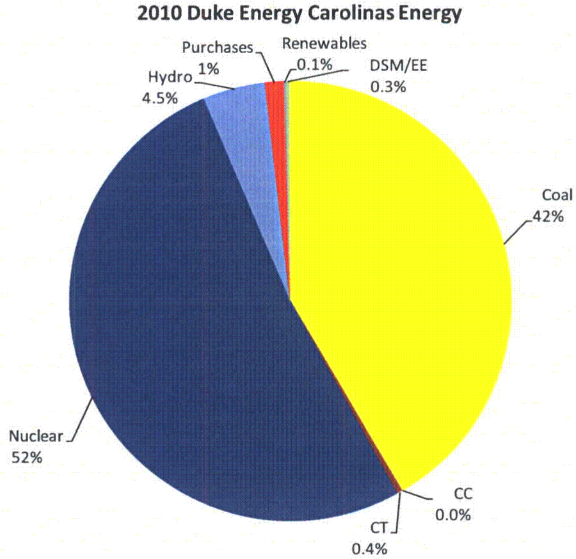
2010 Duke Energy Carolinas Capacity



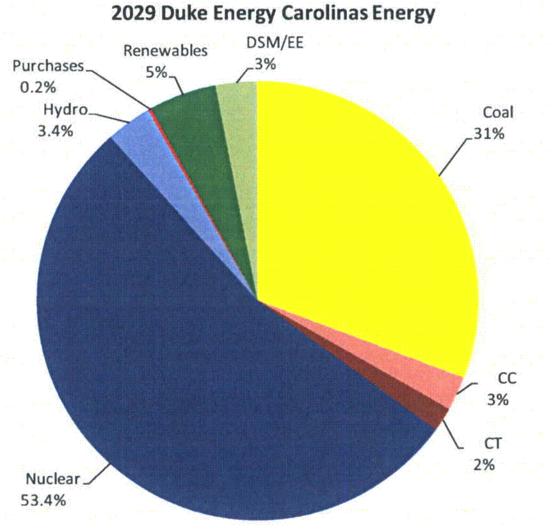
2029 Duke Energy Carolinas Capacity



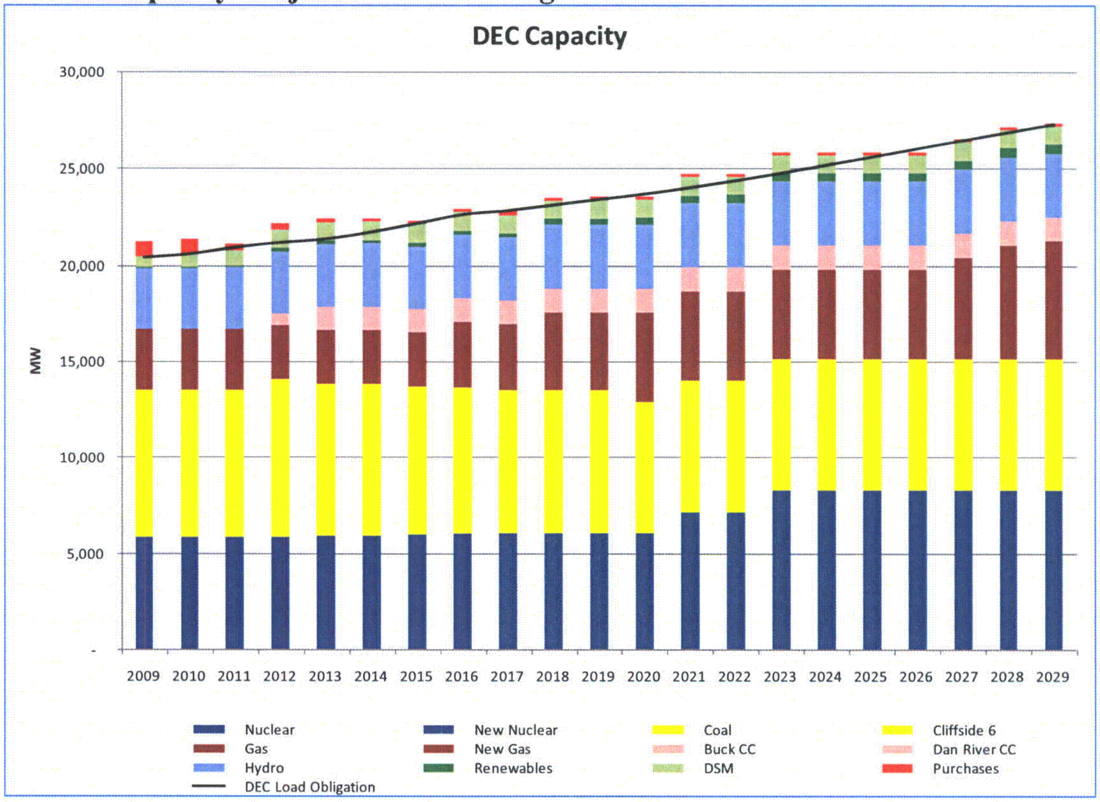
2010 Duke Energy Carolinas Energy



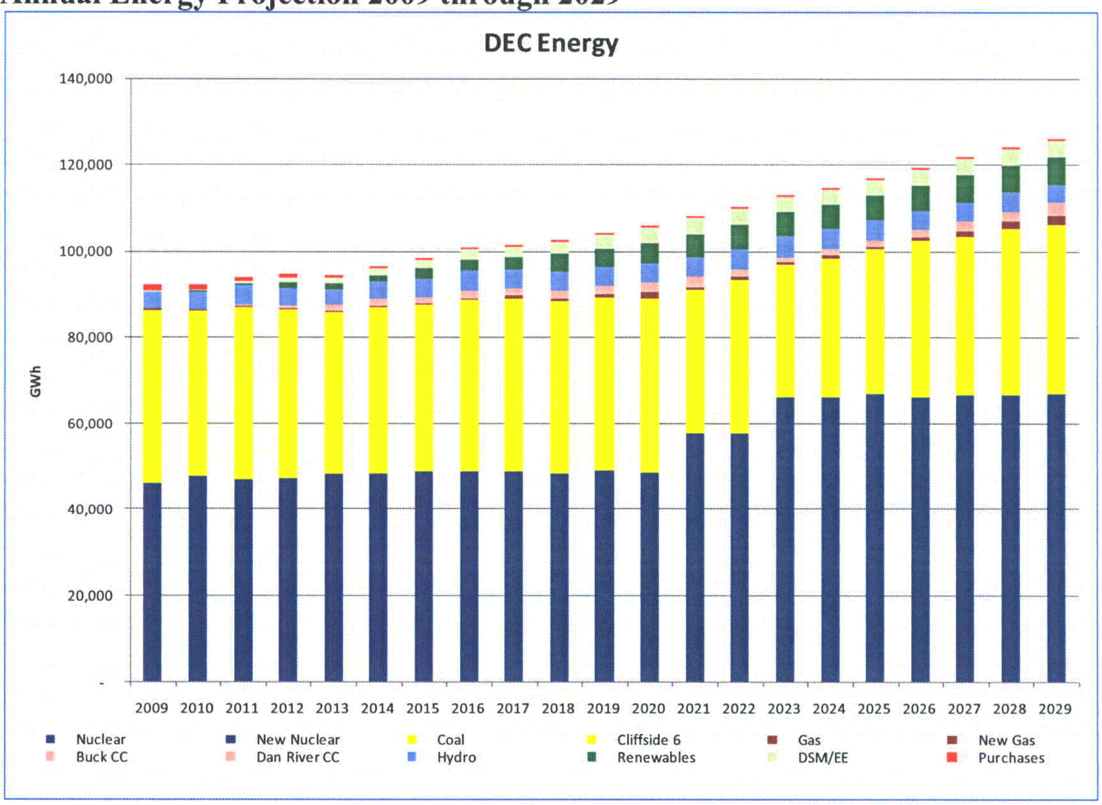
2029 Duke Energy Carolinas Energy



Annual Capacity Projection 2009 through 2029



Annual Energy Projection 2009 through 2029



The table below represents the annual incremental additions reflected in the LCR Table of the most robust expansion plan. The plan contains the addition of Cliffside Unit 6 in 2012, the unit retirements shown in Table 3.3 and the impact of EE and DSM programs.

Year	Month	Project	MW
2009	7	Renewable	3
2009	12	Renewable	3
2010	7	Renewable	9
2010	9	Renewable	12
2011	10	Buck Combined Cycle	620
2012	6	Nuclear Uprates	10
2012	6	Cliffside 6	825
2012	10	Dan River Combined Cycle	620
2012	6	Renewable	144
2013	6	Nuclear Uprates	45
2013	6	Renewable	4
2014	6	Nuclear Uprates	18
2014	6	Renewable	4
2015	6	Nuclear Uprates	51
2015	6	Renewable	4
2016	6	Nuclear Uprates	81
2016	6	Renewable	37
2016	6	New CT	632
2017	6	Renewable	4
2018	6	Renewable	94
2018	6	New CT	632
2019	6	Renewable	19
2020	6	Renewable	34
2020	6	New CT	632
2021	6	Renewable	34
2021	6	Lee Nuclear	1117
2023	6	Renewable	15
2023	6	Lee Nuclear	1117
2025	6	Renewable	15
2027	6	Renewable	23
2027	6	New CT	632
2028	6	New CT	632
2029	6	New CT	190

APPENDICES

APPENDIX A: QUANTITATIVE ANALYSIS

This appendix provides an overview of the quantitative analysis of resource options available to meet customers' future energy needs.

Overview of Analytical Process

Assess Resource Needs

Duke Energy Carolinas estimates the required load and generation resource balance needed to meet future customer demands by assessing:

- Customer load forecast peak and energy – identifying future customer aggregate demands to identify system peak demands and developing the corresponding energy load shape
- Existing supply-side resources – summarizing each existing generation resource's operating characteristics including unit capability, potential operational constraints, and life expectancy
- Operating parameters – determining operational requirements including target planning reserve margins and other regulatory considerations.

Customer load growth coupled with the expiration of purchased power contracts results in significant resource needs to meet energy and peak demands, based on the following assumptions:

- 1.4% average summer peak system demand growth over the next 20 years
- Generation reductions of more than 550 MW due to purchased power contract expirations by 2013
- Generation retirements of approximately 500 MW of old fleet combustion turbines by 2013
- Generation retirements of approximately 1,000 MW of older coal units associated with the addition of Cliffside Unit 6.
- Generation retirements of approximately 625 MW of remaining coal units without scrubbers by 2020.
- Approximately 70 MW of net generation reductions due to new environmental equipment
- Continued operational reliability of existing generation portfolio
- Using a 17 percent target planning reserve margin for the planning horizon

Identify and Screen Resource Options for Further Consideration

The IRP process evaluates demand-side (DSM/EE) and supply-side options to meet customer energy and capacity needs. DSM/EE options for consideration within the IRP are developed based on input from our collaborative partners and cost-effectiveness screening. Supply-side options reflect a diverse mix of technologies and fuel sources (gas, coal, nuclear and renewable) as well as near-term and long-term timing and availability. Supply-side options are initially screened based on the following attributes:

- Technically feasible and commercially available in the marketplace
- Compliant with all federal and state requirements
- Long-run reliability
- Reasonable cost parameters.

Capacity options were compared within their respective fuel types and operational capabilities, with the most cost-effective options being selected for inclusion in the portfolio analysis phase.

Resource Options

<u>Supply-Side</u>
Based on the results of the screening analysis, the following technologies were included in the quantitative analysis as potential supply-side resource options to meet future capacity needs:

- Base Load – 800MW Supercritical Pulverized Coal
- Base Load – 630 MW Integrated Gasification Combined Cycle (IGCC)
- Base Load – 2x1117MW Nuclear units (AP1000)
- Peaking/Intermediate – 4x160MW Combustion Turbines (7FA)
- Peaking/Intermediate –460 MW Unfired+120MW Duct Fired+40MW Inlet Chilled Natural Gas Combined Cycle
- Renewable – 150 MW Existing Unit Biomass Co-Firing
- Renewable – 100 MW Wind PPA - On-Shore
- Renewable – 100 MW Wind PPA – Off-Shore
- Renewable – 2 MW Landfill Gas PPA
- Renewable – 66 MW Solar Photovoltaic PPA
- Renewable – 75 MW Biomass Firing PPA
- Renewable – 15 MW Hog Waste Digester PPA
- Renewable – 55 MW Poultry Waste PPA

Although the supply-side screening curves showed that some of these resources would be screened out, they were included in the next step of the quantitative analysis for completeness. Biomass Firing was constrained to 75 MW per year to limit the amount of wood available to 1 million tons per year. A sensitivity was performed increasing the available wood for biomass firing to 4 million tons per year. For all other resources, the model was used as guidance to determine the sizes of renewable PPAs needed to most economically meet an assumed renewable portfolio standard.

Duke Energy Carolinas has received a CPCN to build one unit of new coal-fired capacity at Cliffside and has modeled this resource as a committed capacity addition in 2012. CPCNs have also been received for the combined cycle additions at Buck and Dan River. The combined cycle additions are reflected in 2012 and 2013 at Buck and Dan River respectively.

Energy Efficiency and Demand-Side Management
EE and DSM programs continue to be an important part of Duke Energy Carolinas' system mix. Both demand response and conservation programs were considered.

The DSM programs were modeled as two separate "bundles" (one bundle of Non-Residential programs and one bundle of Residential programs) that could be selected based on economics. The costs and impacts included in Duke Energy Carolinas' proposed Energy Efficiency Plan settlement in NCUC Docket No. E-7, Sub 831 were modeled and the assumption was made that these costs and impacts would continue throughout the planning period.

The EE programs were modeled as three separate bundles that could be selected based on economics. Bundle 1 corresponded to the costs and impacts for conservation programs included in Duke Energy Carolinas' North Carolina Settlement Energy Efficiency Plan for 2009 through 2012. From years 2013 through 2028 it was assumed that the measures would be replaced in kind (with associated costs) such that there would be no decline in the impacts over time (i.e., continuous commissioning of impacts). Bundles 2 and 3 were modeled identically to Bundle 1, but they were not allowed to start until 2013 and 2017, respectively, and their costs utilized the costs of Bundle 1 escalated based on the market potential study.

Develop Theoretical Portfolio Configurations

A second screening analysis using a simulation model was conducted to identify the most attractive capacity options under the expected load profile as well as under a range of risk cases. This step began with a nominal set of varied inputs to test the system under different future conditions such as changes in fuel prices, load levels, and construction costs. These analyses yielded many different theoretical configurations of resources required to meet an annual 17 percent target planning reserve margin while minimizing the long-run revenue requirements to customers, with differing operating (production) and capital costs.

The nominal set of inputs included:

- Fuel costs and availability for coal, gas, and nuclear generation;
- Development, operation, and maintenance costs of both new and existing generation;
- Compliance with current and potential environmental regulations;
- Cost of capital;
- System operational needs for load ramping, voltage/reactive power support, spinning reserve (10 to 15-minute start-up) and other requirements as a result of Virginia-Carolinas (VACAR) / North America Energy Reliability Corporation (NERC) agreements;
- The projected load and generation resource need; and
- A menu of new resource options with corresponding costs and timing parameters.

Duke Energy Carolinas reviewed a number of variations to the theoretical portfolios to aid in the development of the portfolio options discussed in the following section.

Develop Various Portfolio Options

Using the insights gleaned from developing theoretical portfolios, Duke Energy Carolinas created a representative range of generation plans reflecting plant designs, lead times and environmental emissions limits. Recognizing that different generation plans expose customers to different sources and levels of risk, a variety of portfolios were developed to assess the impact of various risk factors on the costs to serve customers. The portfolios analyzed for the development of this IRP were chosen in order to focus on the near-term (i.e., within the next five years) decisions that must be made while placing less emphasis on peaking needs beyond that timeframe. No alternative portfolios were developed for the peaking capacity needs in the 2016 to 2020 timeframe as Duke Energy Carolinas will have the opportunity to re-visit these needs in subsequent IRPs. For long-term decisions, this year's analysis focused on nuclear need and timing.

While potential new nuclear plant capacity could not go in service until 2018 at the earliest under the current planning assumptions, near-term decisions on continuing to pursue this alternative are needed to preserve this option. The screening results demonstrate that the optimal timing of nuclear varies widely from no nuclear to four units with timeframes from 2018 to 2029. For the purposes of the detailed modeling, portfolios were developed with (1) no nuclear units, (2) one unit in 2018, (3) two-unit plant with staggered operation dates of 2018 and 2019, (4) a three year delay with one unit in 2021, and (5) a two-unit plant with staggered operation dates of 2021 and 2023. The use of these dates is for modeling purposes only and the actual planned operational date may be delayed or accelerated as additional information becomes available on critical issues such as enactment of carbon legislation.

The information as shown on the following pages outlines the planning options that were considered in the portfolio analysis phase. Each portfolio contains the maximum amount of both demand response and conservation that was available and renewable portfolio standard requirements modeled after the NC REPS. In addition, each portfolio contains the addition of Cliffside Unit 6 in 2012, Buck combined cycle in 2012 and Dan River combined cycle in 2013 and the unit retirements shown in Table 3.4.

Conduct Portfolio Analysis

Portfolio options were tested under the nominal set of inputs as well as a variety of risk sensitivities and scenarios, in order to understand the strengths and weaknesses of various resource configurations and evaluate the long-term costs to customers under various potential outcomes. For this IRP analysis, the scenarios considered were as follows:

- Reference Case was developed with CO2 prices based on the Dingle/Boucher bill

The sensitivities chosen to be performed for these scenarios were those representing the highest risks going forward. The following sensitivities were evaluated in the Reference Case scenarios:

- Load forecast variations
  - Increase relative to base forecast (+8% for peak demand and energy by 2029)
  - Decrease relative to base forecast (- 8% for peak demand and energy by 2029)

The sensitivities evaluated in each scenario were as follows:

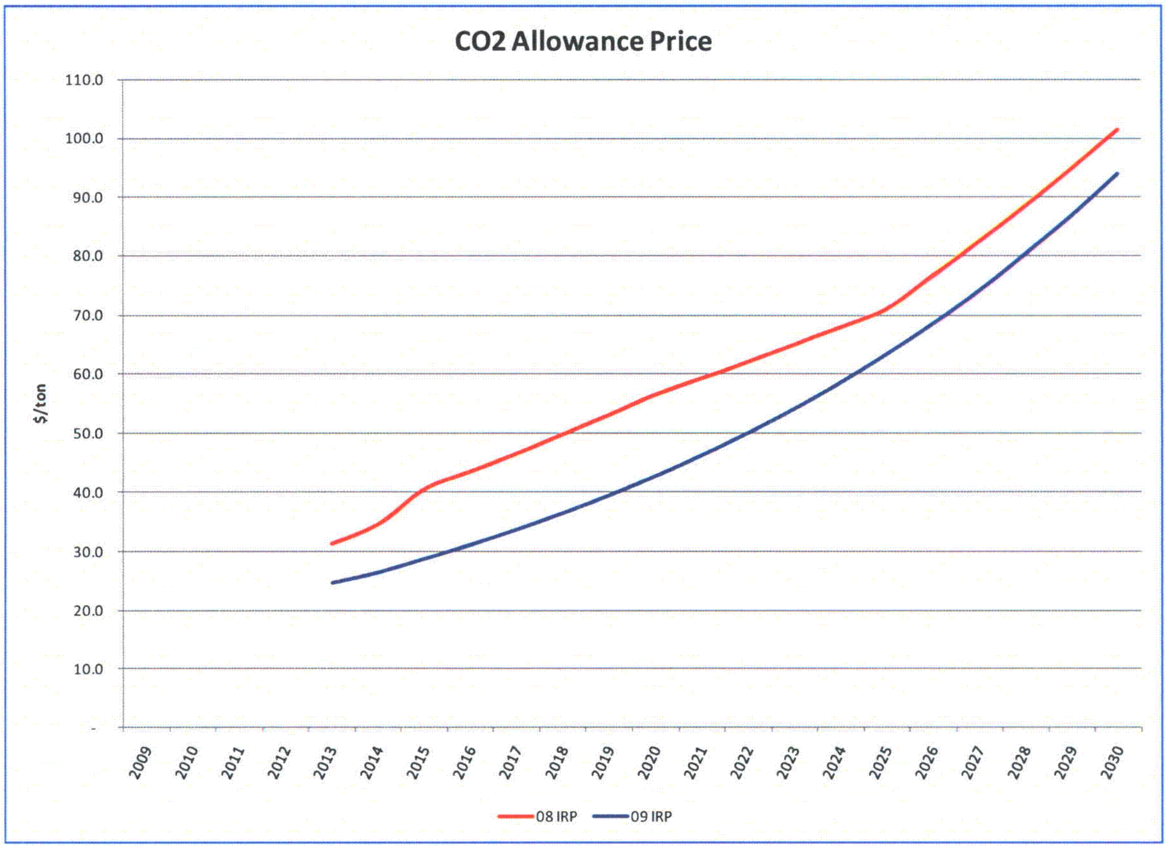
- Construction cost sensitivity[8]
  - Costs to construct a new nuclear plant (+/- 20% higher than base case)
- Fuel price variability
  - Higher Fuel Prices (coal prices 50% higher, natural gas prices 25% higher)
  - Lower Fuel Prices (coal prices 25% lower, natural gas prices 40% lower)
- Emission allowance price variability
  - CAMR was vacated in February 2008 and indications are it will be replaced with unit specific control requirements versus a cap and trade system under CAMR. For this reason mercury allowance values were removed from the analysis.
  - CAIR was vacated in July 2008. At this time it is not clear what regulation or legislation will replace CAIR, but most likely it will be no less stringent than the current rule but just delayed. For the purpose of this analysis, it is assumed from a NOx and SO2 allowance perspective that CAIR is still intact with current market prices through 2010 and fundamental prices from 2011 and beyond.
  - The Carbon reference case had CO_2 emission prices ranging from \$25/ton starting in 2013 to \$94/ton in 2030 with sensitivities of +/- 15%.
- High Energy Efficiency – Included 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 every year after that until the load impacts reach the economic potential identified by the 2007 market potential study. When fully implemented

[8] These sensitivities test the risks from increases in construction costs of one type of supply-side resource at a time. In reality, cost increases of many construction component inputs such as labor, concrete and steel would affect all supply-side resources to varying degrees rather than affecting one technology in isolation.

this increased energy efficiency resulted in approximately a 15% decrease in retail sales.

Chart A1 shows the CO_2 prices utilized in the analysis.

Chart A1



The RPS assumptions are based on recently-enacted legislation in North Carolina. The assumptions for planning purposes are as follows:

Overall Requirements/Timing

- 3% of 2011 load by 2012
- 6% of 2014 load by 2015
- 10% of 2017 load by 2018
- 12.5% of 2020 load by 2021

Additional Requirements

- Up to 25% from EE through 2020
- Up to 40% from EE starting in 2021
- Up to 25% of the requirements can be met with RECs
- Solar requirement (NC only)
  - 0.02% by 2010

    - 0.07% by 2012
    - 0.14% by 2015
    - 0.20% by 2018
- Hog waste requirement (NC only)
    - 0.07% by 2012
    - 0.14% by 2015
    - 0.20% by 2018
- Poultry waste requirement ((NC only - using Duke Energy Carolinas' share of total North Carolina load which is approximately 42%)
    - 71,400 MWh by 2012
    - 294,000 MWh by 2013
    - 378,000 MWh by 2014

The overall requirements were applied to all native loads served by Duke Energy Carolinas (i.e., both retail and wholesale, and regardless of the location of the load) to take into account the potential that a Federal RPS may be imposed that would affect all loads. The requirement that a certain percentage must come from Solar, Hog and Poultry waste was not applied to the South Carolina portion.

Five portfolios were analyzed as shown below:

1. Reference case: Combustion Turbine/Combined Cycle portfolio (CT/CC),
2. 2018 - "One" nuclear unit portfolio (1N 2018)
3. 2018-2019 - "Two" unit nuclear portfolio (2N 2018-2019)
4. 2021 – "One" nuclear unit portfolio (1N 2021)
5. 2021-2023 – "Two" unit nuclear portfolio (2N 2021-2023)

An overview of the specifics of each portfolio is shown in Table A1 below.

Table A1 – Portfolios Evaluated

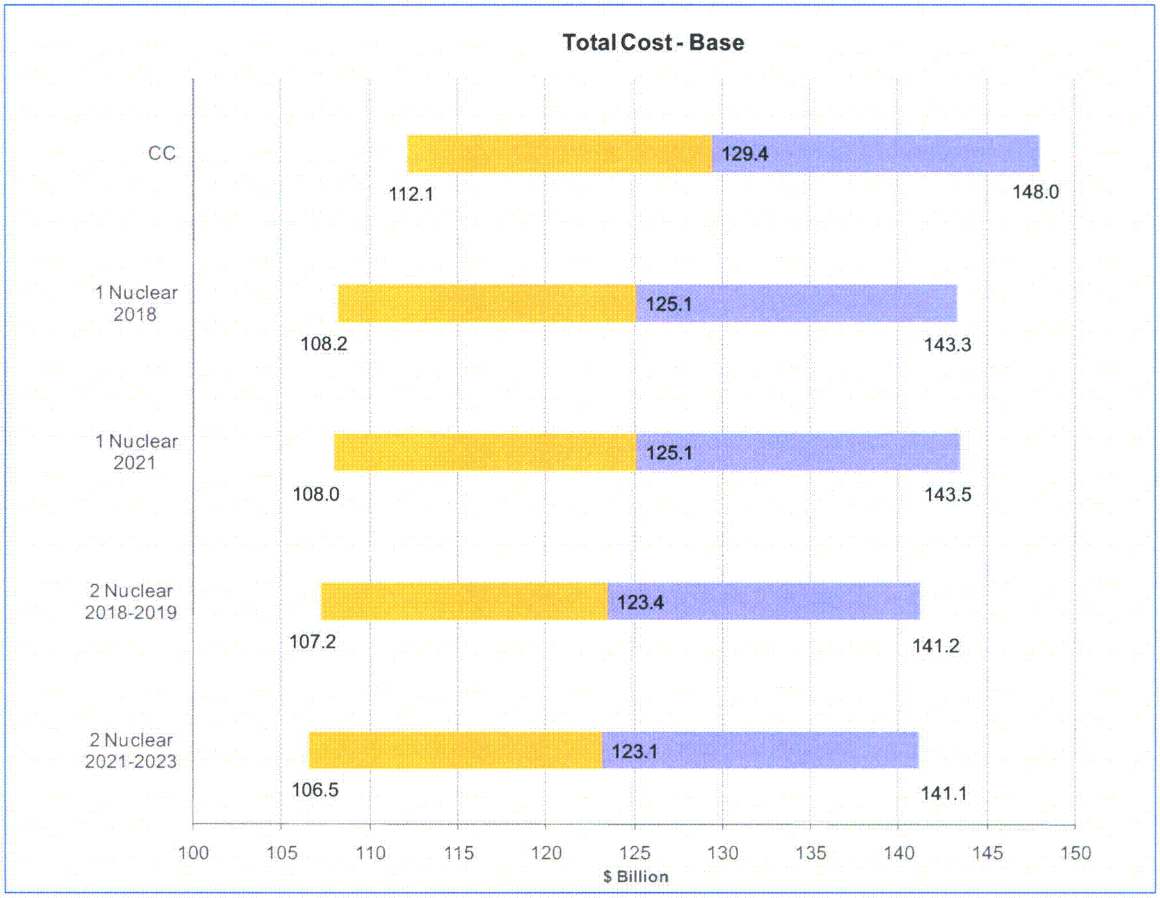
Year	Portfolio				
	CT/CC	1N 2018	1N 2021	2N 2018-2019	2N 2021-2023
2011					
2012					
2013					
2014					
2015					
2016	CT	CT	CT	CT	CT
2017					
2018	CT	N	CT	N	CT
2019				N	
2020	CT	CT	CT		CT
2021	CC		N		N
2022	CC	CT			
2023				CT	N
2024	CT	CC	CC		
2025		CT	CT	CT	
2026	CT			CT	
2027	CT	CT	CT		CT
2028		CT	CT	CT	CT
2029	CT	CT	CT	CT	CT
Total CT	4,338 MW	3,841 MW	3,841 MW	3,340 MW	3,350 MW
Total CC	1,240 MW	620 MW	620 MW		
Total Nuclear		1,117 MW	1,117 MW	2,234 MW	2,234 MW
Total Nuclear Uprate	205 MW	205 MW	205 MW	205 MW	205 MW
Total retire	2,037 MW	2,037 MW	2,037 MW	2,037 MW	2,037 MW

Quantitative Analysis Results

Yearly revenue requirements for various resource planning strategies were calculated based on production cost simulation and capital recovery over a 50-year analysis time frame. The charts below show the PVRRs for a wide range of sensitivities of each portfolio was compared to the PVRRs of other portfolios. The point near the middle of each bar where the color changes is the PVRR for base assumptions. The charts demonstrate how the portfolios perform under base assumptions as well as under a wide range of outcomes. In general, the preferred portfolio has a lower PVRR for base assumptions.

Chart A2 below represent the range of system revenue requirements under each portfolio when load, fuel cost, equipment cost, and CO2 allowance cost is varied. The upper range for each portfolio represents the high load sensitivity, while the lower range for all cases represents the low load sensitivity. For each sensitivity performed the nuclear options resulted in a lower system present value of revenue requirements (PVRR) than the corresponding gas portfolio.

Chart A2



Quantitative Analysis Summary

Due to magnitude of the financial impact that favorable financing can have on the nuclear options, results are shown with traditional financing and with favorable financing.

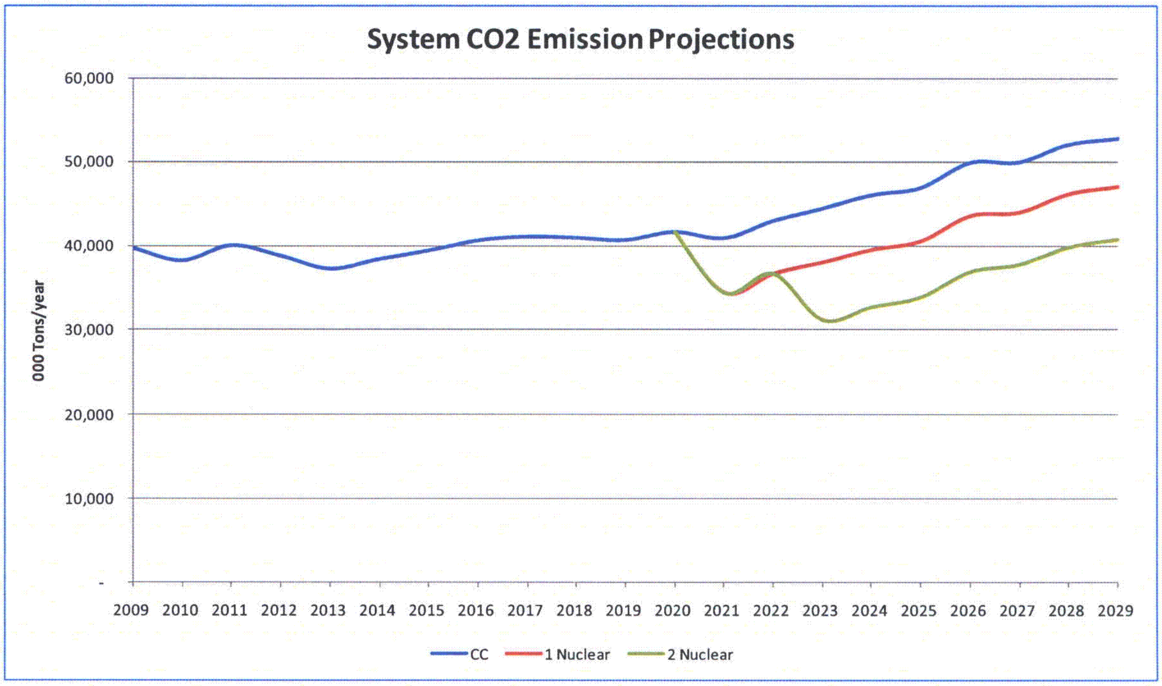
Table A2 - Comparison of Nuclear Portfolios to the Combustion Turbine/Combined Cycle Portfolio

Mid Case Estimate – 40 year nuclear life (2059)		
	Carbon Reference Case CT/CC Portfolio $129 Billion	
Nuclear Option	Traditional Financing	Favorable Financing
Own 1 Unit of a 2 Unit Plant in 2018	$4.3 B Lower	$4.8 B Lower
2 Units in 2018 and 2019	$5.9 B Lower	$6.8 B Lower
Own 1 unit of a 2 Unit Plant in 2021	$4.3 B Lower	$4.8 B Lower
2 Units in 2021 and 2023	$6.2 B Lower	$7.2 B Lower

The values in Table A2 represent the base cost of each portfolio. These values indicate that the nuclear options are preferred in all cases, with the best option being 2 unit delay.

The major benefit of having additional nuclear generation is the lower system CO_2 footprint and the associated economic benefit. The projected CO_2 emissions under the CT/CC, 1N delay and 2N delay scenarios are shown in Chart A3 below. A review of these projections show to make real system reductions in CO_2 emissions additional nuclear generation is needed.

Chart A3



The biggest risks to the nuclear portfolios are the time required to license and construct a nuclear unit, potential for even lower demand than currently estimated, and the ability to secure favorable financing.

In summary, the results of the quantitative analyses indicate that it is prudent for Duke Energy Carolinas to continue to preserve the option to build new nuclear capacity in the 2018-2021 timeframe. The advantages of favorable financing and co-ownership are evident in the analysis above. Duke Energy Carolinas is aggressively pursuing favorable financing options and continues to seek potential co-owners for this generation.

The overall conclusions of the quantitative analysis are that significant additions of baseload, intermediate, peaking, EE, DSM, and renewable resources to the Duke Energy Carolinas portfolio are required over the next decade. Conclusions based on these analyses are:

- The new levels of EE and DSM and the save-a-watt methodology are cost-effective for customers
  - ➢ In every scenario and sensitivity, the portfolios with the new EE and DSM were lower cost than the portfolios with the existing EE and DSM
- Significant renewable resources will be needed to meet the new North Carolina Renewable Energy Portfolio Standard (and potentially a federal standard)
- There is a peaking need in 2016 to 2020 timeframe to maintain the 17% reserve margin in the nuclear delay option.
- The analysis demonstrates that the nuclear option is an attractive option.
  - ➢ Continuing to preserve the option to secure new nuclear generation is prudent.
  - ➢ Favorable financing is very important to the project cost when compared to other generation options.
  - ➢ Co-ownership is beneficial from a generation and risk perspective.

For the purpose of demonstrating that there will be sufficient resources to meet customers' needs, Duke Energy Carolinas has selected a portfolio which, over the 20-year planning horizon provides for the following:

- 961 MW equivalent of incremental capacity under the new save-a-watt demand-side management programs
- 483 MW of new energy efficiency (reduction to system peak load)
- 2,234 MW of new nuclear capacity
- 3,350 MW of new CT capacity
- 205 MW of nuclear uprates
- 458 MW of renewables

Significant challenges remain such as obtaining the necessary regulatory approvals to implement the EE and DSM programs and supply side resources and finding sufficient cost-effective, reliable renewable resources to meet the standard, integrating renewables into the resource mix, and ensuring sufficient transmission capability for these resources.

Duke Energy Carolinas
Spring 2009 Forecast

Sales

Rates Billed

Peaks

2009-2024

July 6, 2009

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Regular Sales and System Peak Summer (2009 Forecast vs. 2010 Forecast)

Regular sales include total Retail and Full/Partial Requirements Wholesale sales (as defined on page 7). The system peak summer demand includes all MW demands associated with Retail classes, Schedule 10A Resale and the total resource needs of the Catawba Joint Owners (as defined on page 15).

Growth Statistics from 2009 to 2010				
	Forecasted 2009	**Forecasted 2010**	**Growth**	
Item	**Amount**	**Amount**	**Amount**	**%**
Regular Sales	78,925 GWH	78,492 GWH	-433 GWH	-0.5%
System Peak Summer	20,398 MW	20,563 MW	165 MW	0.8%

Regular Sales Outlook for the Forecast Horizon (2008 – 2024)

Total Regular sales are expected to grow at an average annual rate of 0.8% from 2008 through 2024. Growth rates for most retail classes of sales are less than the growth projections in the Fall 2008 forecast primarily due to a slower growing economy. Adjustments were made to the energy forecasts for the Fall 2008 Forecasts and the Spring 2009 Forecasts to account for proposed energy efficiency programs and the expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007. Additional adjustments to the Spring 2009 Forecast include sales reductions associated with price increases due to a Carbon Tax starting in 2013 and sales additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011. The Full/Partial Requirements Wholesale class forecast will increase due to new sales contracts with Haywood EMC starting in 2009 and the city of Greenwood SC starting in 2010. One customer of the Full/Partial Requirements Wholesale class, Clemson University, moved from this class to the Duke Carolinas Retail class starting in 2009.

Comparison of Regular Sales Growth Statistics Spring 2009 Forecast vs. Fall 2008 Forecast					
	Spring 2009 Forecast Annual Growth (2008-2024)		Fall 2008 Forecast Annual Growth (2008-2024)		Average Annual Difference [1]
Item	**Amount**	**%**	**Amount**	**%**	
Regular Sales:					
Residential	318 GWH	1.1%	326 GWH	1.1%	-8 GWH
Commercial	443 GWH	1.5%	484 GWH	1.6%	-41 GWH
Industrial (total)	-270 GWH	-1.3%	-76 GWH	-0.3%	-194 GWH
Textile	-213 GWH	-8.4%	-181 GWH	-6.2%	-32 GWH
Other Industrial	-58 GWH	-0.3%	104 GWH	0.6%	-162 GWH
Other [2]	5 GWH	1.5%	4 GWH	1.3%	1 GWH
Full/Partial Wholesale [3]	205 GWH	4.2%	182 GWH	3.8%	23 GWH
Total Regular	700 GWH	0.8%	920 GWH	1.0%	-219 GWH

[1] *Average annual differences may not match due to rounding*
[2] *Other sales consist of Street and Public Lighting and Traffic Signal GWH sales.*
[3] *Full/Partial Wholesale sales include Schedule 10A sales, supplemental sales to the NC EMCs and sales to the city of Greenwood SC.*

System Peak Outlook for the Forecast Horizon (2008 – 2024)

System peak hour demands are forecasted on a summer and winter basis. Adjustments were made to the peak forecasts for the Fall 2008 Forecasts and the Spring 2009 Forecasts to account for the expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007. **These peak forecasts do not include adjustments for proposed energy efficiency programs.** Additional adjustments to the Spring 2009 Forecast include peak reductions associated with price increases due to a Carbon Tax starting in 2013 and peak additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011. The system peak summer demand on the Duke Energy Carolinas is expected to grow at an average annual rate of 1.2% from 2008 through 2024. The system peak winter demand is expected to grow at an average annual rate of 1.2% from 2008 through 2024.

Comparison of System Peak Demand Growth Statistics Spring 2009 Forecast vs. Fall 2008 Forecast					
	Spring 2009 Forecast Annual Growth (2008-2024)		Fall 2008 Forecast Annual Growth (2008-2024)		Average Annual Difference [1]
Item	**Amount**	**%**	**Amount**	**%**	
System Peaks					
Summer	272 MW	1.2%	340 MW	1.5%	-68 MW
Winter	241 MW	1.2%	251 MW	1.2%	-11 MW

Other Forecasts

- The number of rates billed is forecasted for the Residential, Commercial and Industrial classes of Duke Energy Carolinas. The total number of rates billed is expected to grow at 1.5% annually over the forecast horizon.

- The total annual energy requirements of the Catawba Joint Owners are forecasted to grow at 1.6% annually over the forecast horizon.

- Territorial energy requirements are forecasted to grow from 100,483 GWH in 2009 to 118,070 GWH in 2024, for an average annual growth rate of 1.1%.

General forecasting methodology for Duke Energy Carolinas energy and demand forecasts for Spring 2009

Forecast Methodology

Duke Energy Carolinas' Spring 2009 forecasts represent projections of the energy and peak demand needs for its service area, which is located within the states of North and South Carolina, including the major urban areas of Charlotte, Greensboro and Winston-Salem in North Carolina and Spartanburg and Greenville in South Carolina. The forecasts cover the time period of 2009 – 2024 and represent the energy and peak demand needs for the Duke Energy Carolinas system comprised of the following customer classes and other utility/wholesale entities:

- Residential
- Commercial
- Textiles
- Other Industrial
- Other Retail
- Duke Energy Carolinas full /partial requirements wholesale
- Catawba Joint Owners' energy requirements
- Territorial energy requirements

Energy use is dependent upon key economic factors such as income, energy prices and employment along with weather. The general framework of the Company's forecast methodology begins with forecasts of regional economic activity, demographic trends and expected long-term weather. The economic forecasts used in the Spring 2009 forecasts are obtained from Moody's Economy.com, a nationally recognized economic forecasting firm, and include economic forecasts for the two states of North Carolina and South Carolina. These economic forecasts represent long-term projections of numerous economic concepts including the following:

- Total real gross state product (GSP) in NC and SC
- Non-manufacturing real GSP in NC and SC
- Non-manufacturing employment in NC and SC
- Manufacturing real GSP in NC and SC by industry group, e.g., textiles
- Employment in NC and SC by industry group
- Total real personal income

Total population forecasts are obtained from the two states' demographic offices for each county in each state which are then used to derive the total population forecast for the 51 counties that the Company serves in the Carolinas.

General forecasting methodology (continued)

A projection of weather variables, cooling degree days (CDD) and heating degree days (HDD), are made for the forecast period by examining long-term historical weather. For the Spring 2009 forecasts, a 10 year simple average of CDD and HDD were used.

Other factors influencing the forecasts are identified and quantified such as changes in wholesale power contracts, historical billing days and other demographic trends including housing square footage, etc.

Energy forecasts for all of the Company's retail customers are developed at a customer class level, i.e., residential, commercial, textile, other industrial and street lighting along with forecasts for its wholesale customers. Econometric models incorporating the use of industry-standard linear regression techniques were developed utilizing a number of key drivers of energy usage as outlined above. The following provides information about the models.

Residential Class:
The Company's residential class sales forecast is comprised of two separate and independent forecasts. The first is the number of residential rates billed which is driven by population projections of the counties in which the Company provides electric service. The second forecast is energy usage per rate billed which is driven primarily by weather, regional economic and demographic trends, electric price and appliance efficiencies. The total residential sales forecast is derived by multiplying the two forecasts together.

Commercial Class:
Commercial electricity usage changes with the level of regional economic activity and the impact of weather.

Textile Class:
The level of electricity consumption by Duke Energy Carolinas' textile group is very dependent on foreign competition. Usage is also impacted by the level of textile manufacturing output, exchange rates, electric prices and weather.

Other Industrial Class:
Electricity usage for Duke's other industrial customers was forecasted by 15 groups according to the 3 digit NAICS classification and then aggregated to provide the overall other industrial sales forecast. Usage is driven primarily by regional manufacturing output at a 3 digit NAICS level, electric prices and weather.

Other Retail Class:
This class in comprised of public street lighting and traffic signals within the Company's service area. The level of electricity usage is impacted not only by economic growth but also by advances in lighting efficiencies.

General forecasting methodology (continued)

Full / Partial Requirements Wholesale:
Duke Energy Carolinas provides electricity on a contract basis to numerous wholesale customers. The forecast of wholesale sales for this group is developed in two parts: 1) sales provided under the Company's Schedule 10A and driven primarily by regional economic and demographic trends and 2) special contracted sales agreements with other wholesale customers including adjustments for any known or anticipated changes in wholesale contracts.

Catawba Joint Owners:
Their forecast of electricity consumption is driven primarily by regional economic and demographic trends.

Territorial Energy:
Territorial energy is the summation of all the Company's retail sales, full/partial requirement wholesale sales, Nantahala Power & Light's retail and wholesale sales, the Catawba Joint Owners' loads, line losses and company use.

Adjustments were made to the energy forecasts for the Fall 2008 Forecasts and the Spring 2009 Forecasts to account for proposed energy efficiency programs and the expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007. Additional adjustments to the Spring 2009 Forecast include sales reductions associated with price increases due to a Carbon Tax starting in 2013 and sales additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011.

Similarly, Duke Energy Carolinas' forecasts of its annual summer and winter peak demand forecasts uses econometric linear regression models that relate historical annual summer/winter peak demands to key drivers including daily temperature variables (such as daily sum of heating degree hours from 7 to 8AM in the winter with a base of 60 degrees and the daily sum of cooling degree hours from 1 to 5PM in the summer with a base of 69 degrees) and the monthly electricity usage of the entity to be forecasted.

Adjustments were made to the peak forecasts for the Fall 2008 Forecasts and the Spring 2009 Forecasts to account for the expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007. **These peak forecasts do not include adjustments for proposed energy efficiency programs.** Additional adjustments to the Spring 2009 Forecast include peak reductions associated with price increases due to a Carbon Tax starting in 2013 and peak additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011.

Billed Sales and Other Energy Requirements

Regular Sales, which includes billed sales to Retail and Full/Partial Requirements Wholesale classes, are expected to grow at 700 GWH per year or 0.8% over the forecast horizon. Retail sales include GWH sales billed to the Residential, Commercial, Industrial, Street and Public Lighting, and Traffic Signal Service classes. Full/Partial Requirements Wholesale sales include GWH sales billed to municipalities and public utility companies that purchase their full power requirements from the Company, except for power supplied by parallel operation of generation facilities, plus in the forecast period, supplemental sales to specified EMCs in North Carolina and sales to the city of Greenwood, SC.

Regular Sales, as defined here, include Nantahala Power & Light's ("NP&L") retail and wholesale GWH sales.

Adjustments were made to the energy forecasts for the Fall 2008 Forecasts and the Spring 2009 Forecasts to account for proposed energy efficiency programs and the expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007. Additional adjustments to the Spring 2009 Forecast include sales reductions associated with price increases due to a Carbon Tax starting in 2013 and sales additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011.

Points of Interest

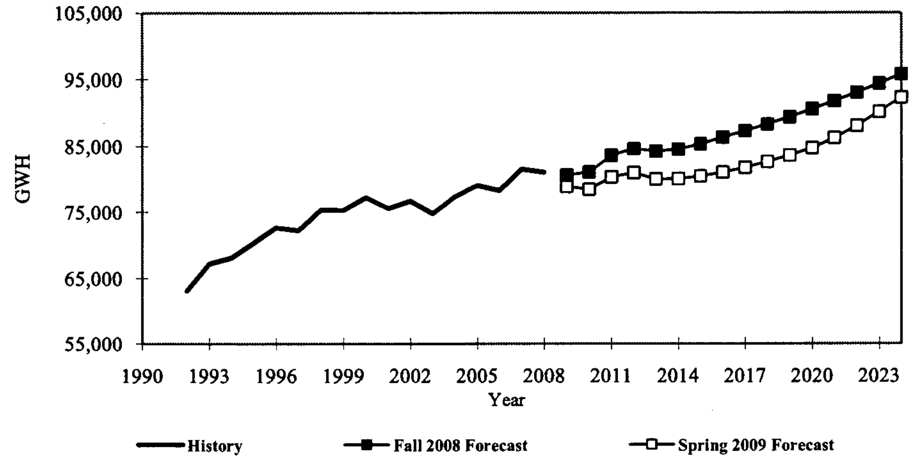
• The **Residential** class continues to show positive growth, driven by steady gains in population within the Duke Energy Carolinas service area. The resulting annual growth in Residential billed sales is expected to average 1.1% over the forecast horizon.

• The **Commercial** class is projected to be the fastest growing retail class, with billed sales growing at 1.5% per year over the next fifteen years. Three sectors that are 44% of Commercial Class sales in 2008 are Offices which includes banking (20%), Retail (13%) and Education (11%). Growth in sales from 2007 to 2008 were positive for Offices (214 GWH) and Education (31 GWH) but negative for Retail (-282 GWH).

• The **Industrial** class continues to struggle due to Textile closings and the economic downturn. Over the forecast horizon, the closing of Textile plants is expected to continue, especially in the near term as the US Bi-Lateral Trade Agreement with China has expired. The Other Industrial class is also expected to decline in the near turn due to the weak economy. In the long term several sectors, such as Rubber & Plastics and Food, are projected to show solid growth whereas other sectors, such as Furniture and Electronics, are projected to decline. Overall, Total Industrial sales are expected to decline 1.3% over the forecast horizon.

• The **Full/Partial Requirements Wholesale** class is expected to grow at 4.2% annually over the forecast horizon, primarily due to the forecasted supplemental sales to specified EMCs in North Carolina.

Regular Billed Sales *(Sum of Retail and Full/Partial Wholesale classes)*



HISTORY

Year	Actual GWH	Growth GWH	Growth %
1999	75,307	-73	-0.1
2000	77,298	1,990	2.6
2001	75,605	-1,692	-2.2
2002	76,769	1,164	1.5
2003	74,784	-1,984	-2.6
2004	77,374	2,590	3.5
2005	79,130	1,756	2.3
2006	78,347	-784	-1.0
2007	81,572	3,225	4.1
2008	81,066	-505	-0.6

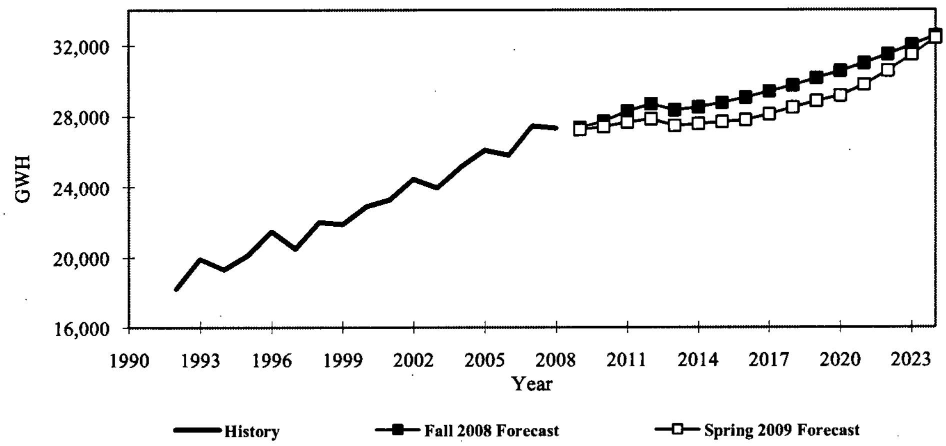
AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2003 to 2008)	1256	1.6
History (1993 to 2008)	927	1.3
Spring 2009 Forecast (2008 to 2024)	700	0.8
Fall 2008 Forecast (2008 to 2024)	920	1.0

SPRING 2009 FORECAST / FALL 2008 FORECAST

Year	GWH	Growth GWH	Growth %	Fall 2008 GWH	Difference from Fall 2008 GWH	Difference from Fall 2008 %
2009	78,925	-2,142	-2.6	80,664	-1,739	-2.2
2010	78,492	-433	-0.5	81,097	-2,605	-3.2
2011	80,353	1,861	2.4	83,605	-3,252	-3.9
2012	81,010	657	0.8	84,605	-3,595	-4.2
2013	80,048	-962	-1.2	84,245	-4,198	-5.0
2014	80,094	46	0.1	84,533	-4,439	-5.3
2015	80,484	390	0.5	85,296	-4,812	-5.6
2016	81,052	568	0.7	86,326	-5,275	-6.1
2017	81,768	716	0.9	87,264	-5,496	-6.3
2018	82,655	887	1.1	88,275	-5,619	-6.4
2019	83,599	944	1.1	89,356	-5,757	-6.4
2020	84,714	1,114	1.3	90,556	-5,843	-6.5
2021	86,223	1,509	1.8	91,772	-5,550	-6.0
2022	88,043	1,820	2.1	93,032	-4,989	-5.4
2023	90,099	2,056	2.3	94,370	-4,271	-4.5
2024	92,271	2,172	2.4	95,780	-3,509	-3.7

Residential Billed Sales



HISTORY

Year	Actual GWH	Growth GWH	Growth %
1999	21,897	-104	-0.5
2000	22,884	987	4.5
2001	23,272	388	1.7
2002	24,466	1,194	5.1
2003	23,947	-519	-2.1
2004	25,150	1,203	5.0
2005	26,108	958	3.8
2006	25,816	-292	-1.1
2007	27,459	1,643	6.4
2008	27,335	-124	-0.5

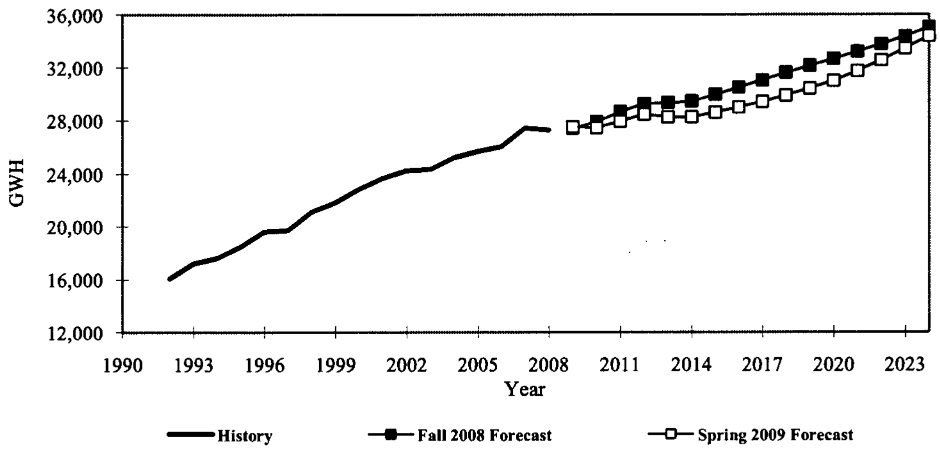
AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2003 to 2008)	678	2.7
History (1993 to 2008)	496	2.1
Spring 2009 Forecast (2008 to 2024)	318	1.1
Fall 2008 Forecast (2008 to 2024)	326	1.1

SPRING 2009 FORECAST / FALL 2008 FORECAST

Year	GWH	Growth GWH	Growth %	Fall 2008 GWH	Difference from Fall 2008 GWH	Difference from Fall 2008 %
2009	27,245	-90	-0.3	27,357	-112	-0.4
2010	27,403	159	0.6	27,718	-315	-1.1
2011	27,669	266	1.0	28,286	-617	-2.2
2012	27,849	180	0.6	28,704	-855	-3.0
2013	27,458	-391	-1.4	28,349	-891	-3.1
2014	27,569	111	0.4	28,517	-948	-3.3
2015	27,686	117	0.4	28,760	-1,074	-3.7
2016	27,785	99	0.4	29,058	-1,273	-4.4
2017	28,119	334	1.2	29,397	-1,278	-4.3
2018	28,489	370	1.3	29,748	-1,259	-4.2
2019	28,862	373	1.3	30,169	-1,307	-4.3
2020	29,171	309	1.1	30,561	-1,390	-4.5
2021	29,788	618	2.1	31,001	-1,213	-3.9
2022	30,582	793	2.7	31,507	-926	-2.9
2023	31,471	889	2.9	32,027	-557	-1.7
2024	32,423	953	3.0	32,552	-128	-0.4

Commercial Billed Sales



HISTORY

Year	Actual GWH	Growth GWH	Growth %
1999	21,807	714	3.4
2000	22,845	1,038	4.8
2001	23,666	821	3.6
2002	24,242	576	2.4
2003	24,355	113	0.5
2004	25,204	849	3.5
2005	25,679	475	1.9
2006	26,030	352	1.4
2007	27,433	1,402	5.4
2008	27,288	-145	-0.5

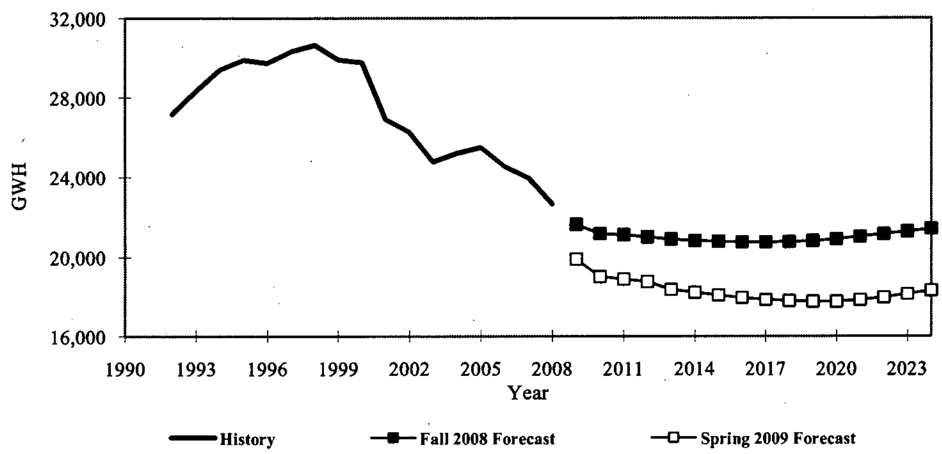
AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2003 to 2008)	587	2.3
History (1993 to 2008)	675	3.1
Spring 2009 Forecast (2008 to 2024)	443	1.5
Fall 2008 Forecast (2008 to 2024)	484	1.6

SPRING 2009 FORECAST / FALL 2008 FORECAST

Year	GWH	Growth GWH	Growth %	Fall 2008 GWH	Difference from Fall 2008 GWH	Difference from Fall 2008 %
2009	27,537	249	0.9	27,399	138	0.5
2010	27,455	-82	-0.3	27,908	-452	-1.6
2011	27,937	482	1.8	28,653	-716	-2.5
2012	28,471	534	1.9	29,265	-794	-2.7
2013	28,252	-219	-0.8	29,326	-1,074	-3.7
2014	28,263	11	0.0	29,454	-1,191	-4.0
2015	28,608	345	1.2	29,950	-1,342	-4.5
2016	28,998	390	1.4	30,491	-1,493	-4.9
2017	29,400	402	1.4	31,023	-1,623	-5.2
2018	29,896	496	1.7	31,596	-1,700	-5.4
2019	30,411	515	1.7	32,120	-1,709	-5.3
2020	30,987	577	1.9	32,627	-1,639	-5.0
2021	31,717	730	2.4	33,194	-1,477	-4.4
2022	32,532	814	2.6	33,748	-1,217	-3.6
2023	33,437	906	2.8	34,356	-919	-2.7
2024	34,376	939	2.8	35,026	-650	-1.9

Total Industrial Billed Sales *(includes Textile and Other Industrial)*



HISTORY

Year	Actual GWH	Growth GWH	Growth %
1999	29,905	-745	-2.4
2000	29,772	-133	-0.4
2001	26,902	-2,869	-9.6
2002	26,259	-643	-2.4
2003	24,764	-1,496	-5.7
2004	25,209	445	1.8
2005	25,495	286	1.1
2006	24,535	-960	-3.8
2007	23,948	-587	-2.4
2008	22,634	-1,314	-5.5

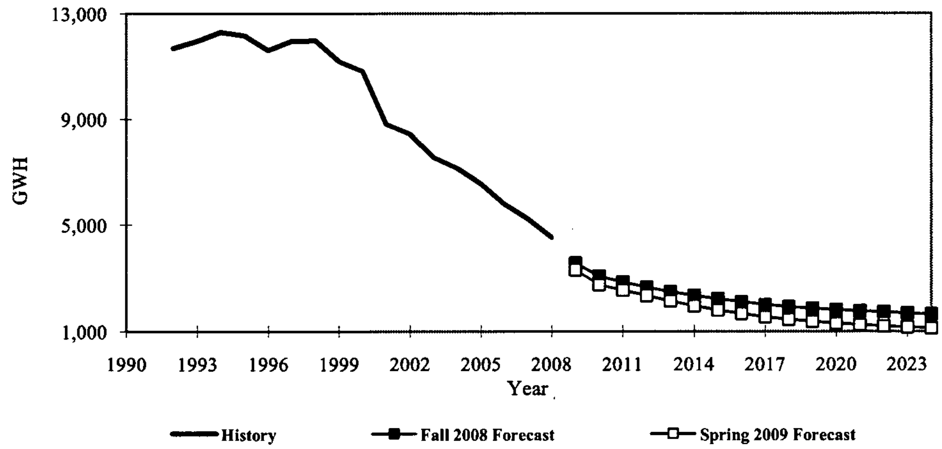
AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2003 to 2008)	-426	-1.8
History (1993 to 2008)	-379	-1.5
Spring 2009 Forecast (2008 to 2024)	-270	-1.3
Fall 2008 Forecast (2008 to 2024)	-76	-0.3

SPRING 2009 FORECAST / FALL 2008 FORECAST

Year	GWH	Growth GWH	Growth %	Fall 2008 GWH	Difference from Fall 2008 GWH	Difference from Fall 2008 %
2009	19,900	-2,734	-12.1	21,631	-1,731	-8.0
2010	19,014	-886	-4.5	21,170	-2,156	-10.2
2011	18,887	-127	-0.7	21,117	-2,231	-10.6
2012	18,750	-137	-0.7	21,007	-2,257	-10.7
2013	18,356	-394	-2.1	20,895	-2,539	-12.2
2014	18,213	-143	-0.8	20,819	-2,606	-12.5
2015	18,066	-147	-0.8	20,772	-2,705	-13.0
2016	17,929	-138	-0.8	20,752	-2,823	-13.6
2017	17,831	-98	-0.5	20,744	-2,913	-14.0
2018	17,768	-63	-0.4	20,752	-2,984	-14.4
2019	17,739	-29	-0.2	20,811	-3,072	-14.8
2020	17,744	5	0.0	20,895	-3,151	-15.1
2021	17,822	78	0.4	21,028	-3,206	-15.2
2022	17,947	125	0.7	21,148	-3,202	-15.1
2023	18,119	172	1.0	21,279	-3,160	-14.9
2024	18,306	187	1.0	21,413	-3,107	-14.5

Textile Billed Sales



HISTORY

Year	Actual GWH	Growth GWH	Growth %
1999	11,196	-780	-6.5
2000	10,814	-382	-3.4
2001	8,825	-1,989	-18.4
2002	8,443	-382	-4.3
2003	7,562	-881	-10.4
2004	7,147	-415	-5.5
2005	6,561	-586	-8.2
2006	5,791	-770	-11.7
2007	5,224	-567	-9.8
2008	4,524	-700	-13.4

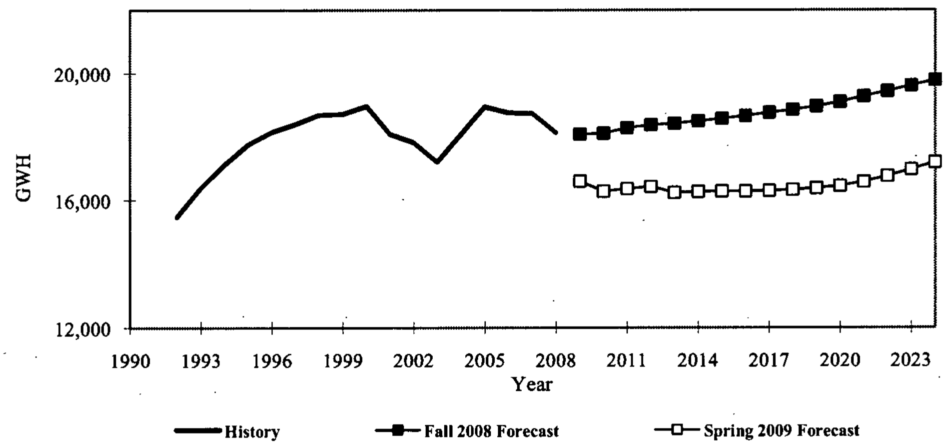
AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2003 to 2008)	-608	-9.8
History (1993 to 2008)	-495	-6.3
Spring 2009 Forecast (2008 to 2024)	-213	-8.4
Fall 2008 Forecast (2008 to 2024)	-181	-6.2

SPRING 2009 FORECAST / FALL 2008 FORECAST

Year	GWH	Growth GWH	Growth %	Fall 2008 GWH	Difference from Fall 2008 GWH	Difference from Fall 2008 %
2009	3,308	-1,216	-26.9	3,557	-249	-7.0
2010	2,741	-567	-17.1	3,068	-327	-10.7
2011	2,535	-206	-7.5	2,846	-311	-10.9
2012	2,332	-203	-8.0	2,639	-307	-11.6
2013	2,125	-207	-8.9	2,478	-353	-14.2
2014	1,953	-172	-8.1	2,335	-382	-16.4
2015	1,798	-155	-7.9	2,209	-411	-18.6
2016	1,657	-141	-7.8	2,096	-439	-20.9
2017	1,539	-119	-7.2	1,987	-449	-22.6
2018	1,442	-97	-6.3	1,906	-464	-24.3
2019	1,367	-75	-5.2	1,851	-484	-26.2
2020	1,302	-65	-4.8	1,804	-502	-27.8
2021	1,246	-56	-4.3	1,758	-512	-29.1
2022	1,193	-53	-4.3	1,715	-522	-30.4
2023	1,157	-36	-3.0	1,673	-516	-30.8
2024	1,120	-37	-3.2	1,632	-512	-31.4

Other Industrial Billed Sales



HISTORY

Year	Actual GWH	Growth GWH	Growth %
1999	18,709	35	0.2
2000	18,957	249	1.3
2001	18,077	-880	-4.6
2002	17,816	-261	-1.4
2003	17,202	-614	-3.4
2004	18,063	861	5.0
2005	18,934	872	4.8
2006	18,744	-191	-1.0
2007	18,724	-20	-0.1
2008	18,110	-614	-3.3

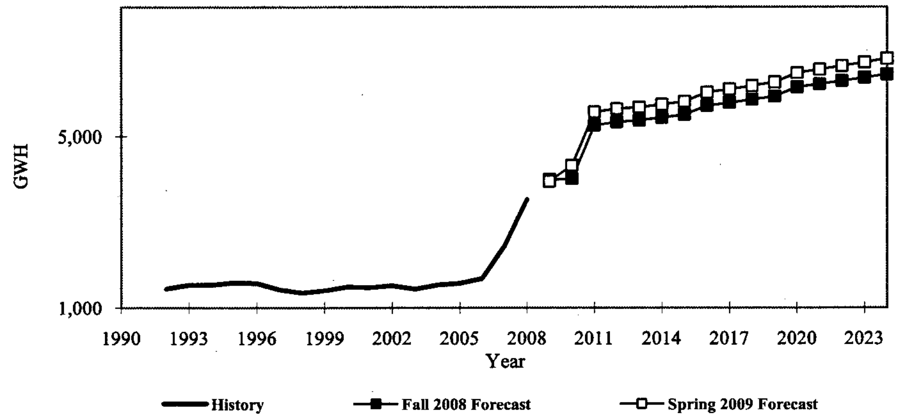
AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2003 to 2008)	182	1.0
History (1993 to 2008)	116	0.7
Spring 2009 Forecast (2008 to 2024)	-58	-0.3
Fall 2008 Forecast (2008 to 2024)	104	0.6

SPRING 2009 FORECAST / FALL 2008 FORECAST

Year	Spring 2009 GWH	Growth GWH	Growth %	Fall 2008 GWH	Difference from Fall 2008 GWH	Difference from Fall 2008 %
2009	16,592	-1,518	-8.4	18,074	-1,482	-8.2
2010	16,273	-319	-1.9	18,102	-1,829	-10.1
2011	16,351	79	0.5	18,271	-1,920	-10.5
2012	16,418	66	0.4	18,368	-1,950	-10.6
2013	16,231	-187	-1.1	18,417	-2,186	-11.9
2014	16,260	29	0.2	18,485	-2,224	-12.0
2015	16,269	8	0.1	18,563	-2,295	-12.4
2016	16,271	3	0.0	18,656	-2,384	-12.8
2017	16,292	21	0.1	18,757	-2,465	-13.1
2018	16,326	34	0.2	18,846	-2,520	-13.4
2019	16,372	46	0.3	18,959	-2,588	-13.6
2020	16,442	70	0.4	19,091	-2,650	-13.9
2021	16,576	134	0.8	19,270	-2,695	-14.0
2022	16,754	178	1.1	19,433	-2,679	-13.8
2023	16,962	208	1.2	19,606	-2,644	-13.5
2024	17,187	225	1.3	19,781	-2,595	-13.1

Full / Partial Requirements Wholesale Billed Sales [1]



HISTORY

Year	Actual GWH	Growth GWH	Growth %
1999	1,412	53	3.9
2000	1,500	88	6.3
2001	1,484	-16	-1.1
2002	1,530	47	3.1
2003	1,448	-82	-5.4
2004	1,542	93	6.4
2005	1,580	38	2.5
2006	1,694	114	7.2
2007	2,454	760	44.8
2008	3,525	1,072	43.7

AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2003 to 2008)	415	19.5
History (1993 to 2008)	132	5.6
Spring 2009 Forecast (2008 to 2024)	205	4.2
Fall 2008 Forecast (2008 to 2024)	182	3.8

SPRING 2009 FORECAST / FALL 2008 FORECAST

Year	GWH	Growth GWH	Growth %	Fall 2008 GWH	Difference from Fall 2008 GWH	Difference from Fall 2008 %
2009	3,956	431	12.2	3,996	-40	-1.0
2010	4,330	373	9.4	4,016	314	7.8
2011	5,567	1,237	28.6	5,259	308	5.9
2012	5,642	75	1.4	5,335	307	5.8
2013	5,678	36	0.6	5,377	301	5.6
2014	5,740	62	1.1	5,439	300	5.5
2015	5,810	70	1.2	5,507	302	5.5
2016	6,021	211	3.6	5,715	306	5.4
2017	6,094	73	1.2	5,784	311	5.4
2018	6,174	79	1.3	5,858	316	5.4
2019	6,254	80	1.3	5,932	322	5.4
2020	6,473	219	3.5	6,145	328	5.3
2021	6,551	78	1.2	6,216	335	5.4
2022	6,634	83	1.3	6,290	344	5.5
2023	6,717	84	1.3	6,365	353	5.5
2024	6,805	88	1.3	6,443	363	5.6

1 Schedule 10A Resale Sales does not include SEPA allocation.

Duke Energy Carolinas owns 12.5% of the capacity of the Catawba Nuclear Station Units 1 and 2.

The remaining 87.5% is owned by the North Carolina Municipal Power Agency #1 (37.5%), Piedmont Municipal Power Agency (12.5%), North Carolina Electric Membership Corporation (28.1%) and Saluda River Electric Cooperative, Inc. (9.4%).

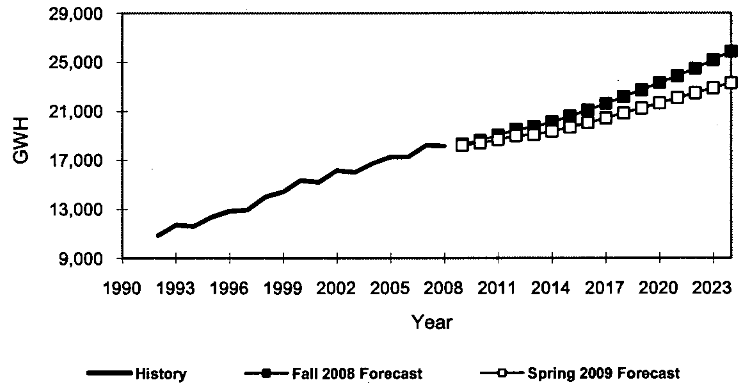
(In December 2006 Duke Energy Carolinas and North Carolina Electric Membership Corporation announced agreements to buy Saluda River Electric Cooperative, Inc.'s ownership interest in unit 1 of the Catawba Nuclear Station. Duke Energy Carolinas will then own 19.3% of the capacity of the Catawba Nuclear Station Units 1 and 2 and North Carolina Electric Membership Corporation will own 30.7% of the capacity of the Catawba Nuclear Station Units 1 and 2.)

In addition to the power supplied from the ownership share in the Catawba stations, each Catawba Joint Owner must purchase supplemental power to meet its total energy requirements.The Catawba forecast represents the total energy requirements of the Catawba Joint Owners.

Total Catawba electric energy requirements are expected to increase at an average annual growth of 322 GWH per year and a growth rate of 1.6 % per year over the period from 2008-2024.

Additional adjustments were made to the Catawba Sales forecasts to account for the expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007.

Catawba Total Delivered Energy Requirements [1]



HISTORY

YEAR	Actual GWH	GROWTH GWH	GROWTH %
1999	14,413	413	2.9
2000	15,354	941	6.5
2001	15,184	-170	-1.1
2002	16,151	967	6.4
2003	15,986	-165	-1.0
2004	16,711	725	4.5
2005	17,237	527	3.2
2006	17,246	9	0.0
2007	18,200	954	5.5
2008	18,140	-60	-0.3

AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2003 to 2008)	431	2.6
History (1993 to 2008)	431	3.0
Spring 2009 Forecast (2008 to 2024)	322	1.6
Fall 2008 Forecast (2008 to 2024)	483	2.2

SPRING 2009 FORECAST / FALL 2008 FORECAST

Year	GWH	Growth GWH	Growth %	Fall 2008 GWH	Difference from Fall 2008 GWH	Difference from Fall 2008 %
2009	18,205	65	0.4	18,315	-110	-0.6
2010	18,419	214	1.2	18,625	-206	-1.1
2011	18,701	281	1.5	19,051	-350	-1.8
2012	19,008	307	1.6	19,515	-507	-2.6
2013	19,077	69	0.4	19,719	-643	-3.3
2014	19,370	294	1.5	20,138	-767	-3.8
2015	19,703	333	1.7	20,598	-895	-4.3
2016	20,060	357	1.8	21,087	-1,027	-4.9
2017	20,441	381	1.9	21,607	-1,165	-5.4
2018	20,843	402	2.0	22,155	-1,312	-5.9
2019	21,247	404	1.9	22,718	-1,471	-6.5
2020	21,655	408	1.9	23,295	-1,640	-7.0
2021	22,063	408	1.9	23,861	-1,798	-7.5
2022	22,473	410	1.9	24,470	-1,997	-8.2
2023	22,882	409	1.8	25,155	-2,273	-9.0
2024	23,294	412	1.8	25,865	-2,571	-9.9

1 Total Delivery for Catawba Joint Owners includes SEPA allocations

Territorial Energy

Territorial energy requirements consist of:

. Regular Sales (excluding supplemental sales to NC EMCs)
. Catawba Joint Owner energy requirements
. Southeastern Power Administration ("SEPA") energy allocations that are wheeled to municipal and cooperative electric systems within the Duke Energy Carolinas' service area
. Duke Energy Carolinas company use
. System losses and unbilled energy

Territorial energy requirements are forecasted to grow 1.1% per year from 2009 to 2024. All values below are expressed in GWH.

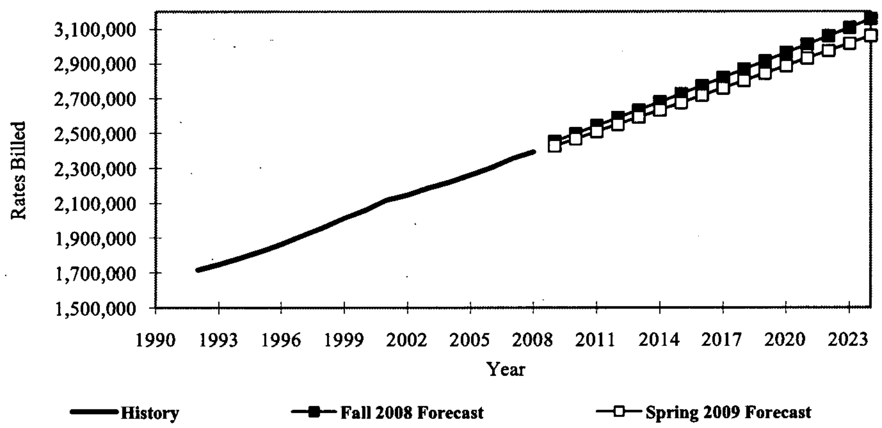
Year	Regular Sales [1]	Catawba (Less SEPA) Total [2]	SEPA [3]	Company Use [4]	Losses & Unbilled [5 & 6]	Territorial Energy
2009	76,632	17,905	311	217	5,419	100,483
2010	76,192	18,119	311	217	5,393	100,231
2011	76,858	18,400	311	217	5,460	101,247
2012	77,482	18,708	311	217	5,538	102,254
2013	76,501	18,776	311	217	5,570	101,375
2014	76,522	19,070	311	217	5,632	101,752
2015	76,883	19,403	311	217	5,693	102,507
2016	77,280	19,760	311	217	5,759	103,327
2017	77,966	20,141	311	217	5,828	104,462
2018	78,817	20,543	311	217	5,903	105,791
2019	79,723	20,947	311	217	5,984	107,182
2020	80,662	21,355	311	217	6,070	108,615
2021	82,136	21,763	311	217	6,168	110,594
2022	83,917	22,173	311	217	6,271	112,889
2023	85,933	22,582	311	217	6,379	115,421
2024	88,060	22,994	311	217	6,489	118,070

[1] Regular Sales represents total electricity used by Duke Energy Carolinas Retail and Schedule 10A Resale classes and the city of Greenwood SC. Supplemental sales to NC EMCs are not included in this column.
[2] Catawba Total represents Catawba Joint Owner electricity requirements less their SEPA allocations.
[3] SEPA represents hydro energy allocated to the municipalities and co-operatives and wheeled by Duke Energy Carolinas.
[4] Company Use represents electricity used by Duke Energy Carolinas offices and facilities.
[5] Losses represent electricity line losses from generation sources to customer meters.
[6] Unbilled Sales represent the adjustment made to create calendar period sales from billing period sales.

Number of Rates Billed

Total Rates Billed

(Sum of Major Retail Classes: Residential, Commercial and Industrial)



HISTORY

Year	Actual Rates Billed	Growth Rates Billed	%
1999	2,013,039	54,039	2.8
2000	2,059,152	46,113	2.3
2001	2,117,432	58,280	2.8
2002	2,148,117	30,685	1.4
2003	2,186,825	38,708	1.8
2004	2,221,590	34,766	1.6
2005	2,261,639	40,049	1.8
2006	2,304,050	42,411	1.9
2007	2,354,078	50,028	2.2
2008	2,393,426	39,348	1.7

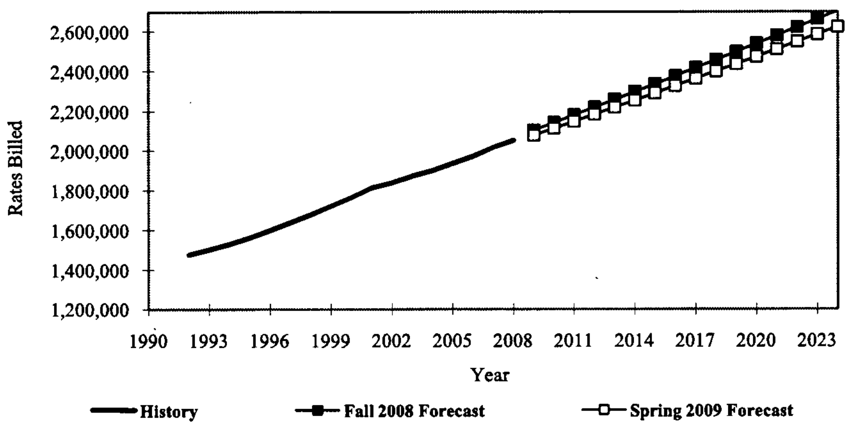
AVERAGE ANNUAL GROWTH

	Rates Billed Per Year	% Per Year
History (2003 to 2008)	41,320	1.8
History (1993 to 2008)	43,154	2.1
Spring 2009 Forecast (2008 to 2024)	41,657	1.5
Fall 2008 Forecast (2008 to 2024)	47,647	1.7

SPRING 2009 FORECAST / FALL 2008 FORECAST

Year	Rates Billed	Growth Rates Billed	%	Fall 2008 Rates Billed	Difference from Fall 2008 Rates Billed	Difference from Fall 2008 %
2009	2,426,244	32,818	1.4	2,452,452	-26,208	-1.1
2010	2,466,674	40,431	1.7	2,497,526	-30,852	-1.2
2011	2,508,505	41,831	1.7	2,542,459	-33,953	-1.3
2012	2,549,910	41,404	1.7	2,587,631	-37,722	-1.5
2013	2,590,948	41,038	1.6	2,632,978	-42,030	-1.6
2014	2,632,075	41,127	1.6	2,678,504	-46,429	-1.7
2015	2,673,533	41,458	1.6	2,724,470	-50,937	-1.9
2016	2,715,689	42,156	1.6	2,771,270	-55,581	-2.0
2017	2,758,045	42,356	1.6	2,818,393	-60,348	-2.1
2018	2,800,480	42,434	1.5	2,865,681	-65,201	-2.3
2019	2,843,015	42,536	1.5	2,913,141	-70,126	-2.4
2020	2,885,825	42,810	1.5	2,960,945	-75,120	-2.5
2021	2,929,140	43,315	1.5	3,009,335	-80,195	-2.7
2022	2,972,649	43,509	1.5	3,057,995	-85,346	-2.8
2023	3,016,248	43,599	1.5	3,106,805	-90,557	-2.9
2024	3,059,943	43,695	1.4	3,155,774	-95,831	-3.0

Residential Rates Billed



HISTORY

Year	Actual Rates Billed	Growth Rates Billed	%
1999	1,722,110	44,175	2.6
2000	1,764,183	42,073	2.4
2001	1,813,867	49,684	2.8
2002	1,839,689	25,822	1.4
2003	1,872,484	32,795	1.8
2004	1,901,335	28,851	1.5
2005	1,935,320	33,985	1.8
2006	1,971,673	36,353	1.9
2007	2,016,104	44,431	2.3
2008	2,052,252	36,149	1.8

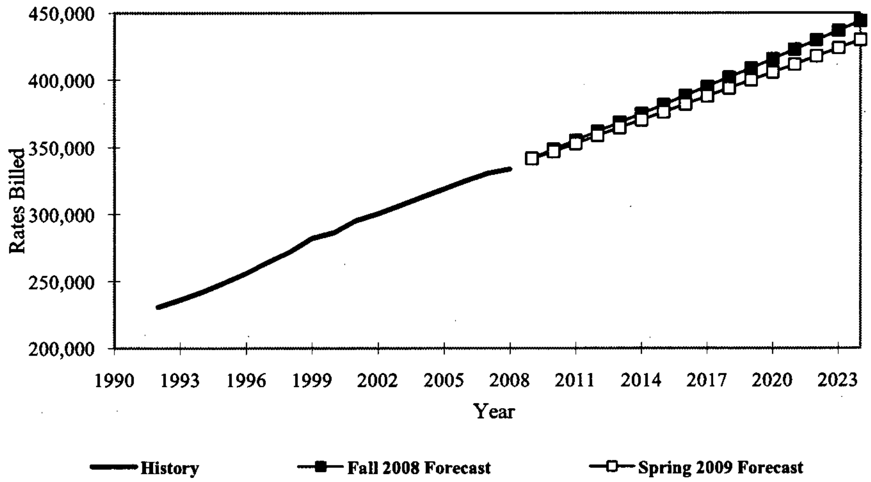
AVERAGE ANNUAL GROWTH

	Rates Billed Per Year	% Per Year
History (2003 to 2008)	35,954	1.9
History (1993 to 2008)	36,730	2.1
Spring 2009 Forecast (2008 to 2024)	35,691	1.5
Fall 2008 Forecast (2008 to 2024)	40,794	1.7

SPRING 2009 FORECAST / FALL 2008 FORECAST

Year	Rates Billed	Growth Rates Billed	%	Fall 2008: Rates Billed	Difference from Fall 2008 Rates Billed	%
2009	2,077,649	25,397	1.2	2,103,405	-25,756	-1.2
2010	2,112,971	35,322	1.7	2,141,871	-28,900	-1.3
2011	2,148,767	35,796	1.7	2,180,307	-31,540	-1.4
2012	2,184,358	35,591	1.7	2,218,953	-34,596	-1.6
2013	2,219,833	35,475	1.6	2,257,757	-37,924	-1.7
2014	2,255,283	35,450	1.6	2,296,716	-41,433	-1.8
2015	2,290,977	35,694	1.6	2,336,059	-45,081	-1.9
2016	2,327,252	36,274	1.6	2,376,111	-48,859	-2.1
2017	2,363,701	36,449	1.6	2,416,425	-52,724	-2.2
2018	2,400,220	36,519	1.5	2,456,880	-56,659	-2.3
2019	2,436,820	36,600	1.5	2,497,478	-60,658	-2.4
2020	2,473,644	36,824	1.5	2,538,368	-64,724	-2.5
2021	2,510,887	37,243	1.5	2,579,752	-68,865	-2.7
2022	2,548,288	37,401	1.5	2,621,357	-73,069	-2.8
2023	2,585,760	37,472	1.5	2,663,090	-77,330	-2.9
2024	2,623,311	37,551	1.5	2,704,960	-81,648	-3.0

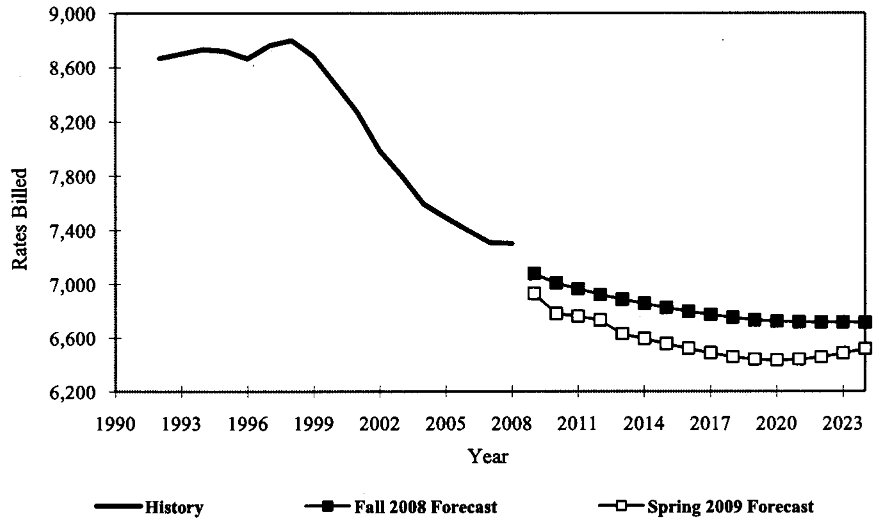
Commercial Rates Billed



HISTORY				AVERAGE ANNUAL GROWTH		
Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
1999	282,248	9,983	3.7			
2000	286,495	4,247	1.5			
2001	295,300	8,805	3.1			
2002	300,440	5,140	1.7			
2003	306,540	6,101	2.0			
2004	312,665	6,125	2.0	History (2003 to 2008)	5,467	1.7
2005	318,827	6,162	2.0	History (1993 to 2008)	6,517	2.3
2006	324,977	6,150	1.9			
2007	330,666	5,689	1.8	Spring 2009 Forecast (2008 to 2024)	6,015	1.6
2008	333,873	3,208	1.0	Fall 2008 Forecast (2008 to 2024)	6,889	1.8

SPRING 2009 FORECAST				FALL 2008 FORECAST		
		Growth			Difference from Fall 2008	
Year	Rates Billed	Rates Billed	%	Rates Billed	Rates Billed	%
2009	341,662	7,789	2.3	341,969	-307	-0.1
2010	346,920	5,257	1.5	348,648	-1,728	-0.5
2011	352,977	6,057	1.7	355,188	-2,211	-0.6
2012	358,819	5,842	1.7	361,755	-2,936	-0.8
2013	364,484	5,666	1.6	368,334	-3,850	-1.0
2014	370,197	5,713	1.6	374,932	-4,735	-1.3
2015	375,998	5,801	1.6	381,587	-5,589	-1.5
2016	381,916	5,917	1.6	388,361	-6,446	-1.7
2017	387,856	5,941	1.6	395,194	-7,337	-1.9
2018	393,800	5,944	1.5	402,049	-8,249	-2.1
2019	399,755	5,955	1.5	408,928	-9,173	-2.2
2020	405,748	5,992	1.5	415,854	-10,106	-2.4
2021	411,814	6,066	1.5	422,863	-11,049	-2.6
2022	417,904	6,090	1.5	429,920	-12,016	-2.8
2023	424,002	6,098	1.5	436,998	-12,996	-3.0
2024	430,113	6,111	1.4	444,099	-13,986	-3.1

Total Industrial Rates Billed *(Includes Textile and Other Industrial)*



HISTORY

Year	Actual Rates Billed	Growth Rates Billed	%
1999	8,681	-119	-1.3
2000	8,474	-207	-2.4
2001	8,265	-210	-2.5
2002	7,989	-276	-3.3
2003	7,801	-188	-2.3
2004	7,591	-210	-2.7
2005	7,492	-99	-1.3
2006	7,401	-91	-1.2
2007	7,309	-92	-1.2
2008	7,301	-8	-0.1

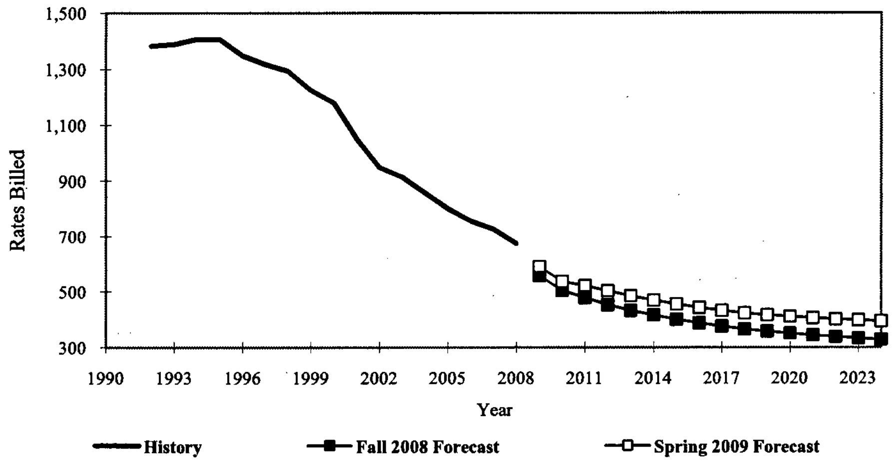
AVERAGE ANNUAL GROWTH

	Rates Billed Per Year	% Per Year
History (2003 to 2008)	-100	-1.3
History (1993 to 2008)	-93	-1.2
Spring 2009 Forecast (2008 to 2024)	-49	-0.7
Fall 2008 Forecast (2008 to 2024)	-37	-0.5

SPRING 2009 FORECAST / FALL 2008 FORECAST

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	Difference from Fall 2008 Rates Billed	%
2009	6,933	-368	-5.0	7,078	-145	-2.0
2010	6,783	-149	-2.2	7,007	-224	-3.2
2011	6,761	-22	-0.3	6,964	-202	-2.9
2012	6,733	-28	-0.4	6,923	-190	-2.7
2013	6,631	-102	-1.5	6,887	-256	-3.7
2014	6,595	-36	-0.5	6,856	-261	-3.8
2015	6,557	-38	-0.6	6,825	-268	-3.9
2016	6,522	-36	-0.5	6,798	-276	-4.1
2017	6,488	-34	-0.5	6,774	-286	-4.2
2018	6,459	-29	-0.4	6,752	-293	-4.3
2019	6,440	-19	-0.3	6,734	-295	-4.4
2020	6,434	-6	-0.1	6,724	-290	-4.3
2021	6,440	6	0.1	6,720	-281	-4.2
2022	6,457	17	0.3	6,718	-261	-3.9
2023	6,486	29	0.4	6,717	-231	-3.4
2024	6,519	33	0.5	6,715	-196	-2.9

Textile Rates Billed



HISTORY

Year	Actual Rates Billed	Growth Rates Billed	%
1999	1,226	-67	-5.2
2000	1,181	-45	-3.7
2001	1,052	-129	-10.9
2002	949	-103	-9.8
2003	914	-35	-3.6
2004	857	-57	-6.2
2005	802	-56	-6.5
2006	757	-45	-5.6
2007	728	-29	-3.8
2008	675	-53	-7.3

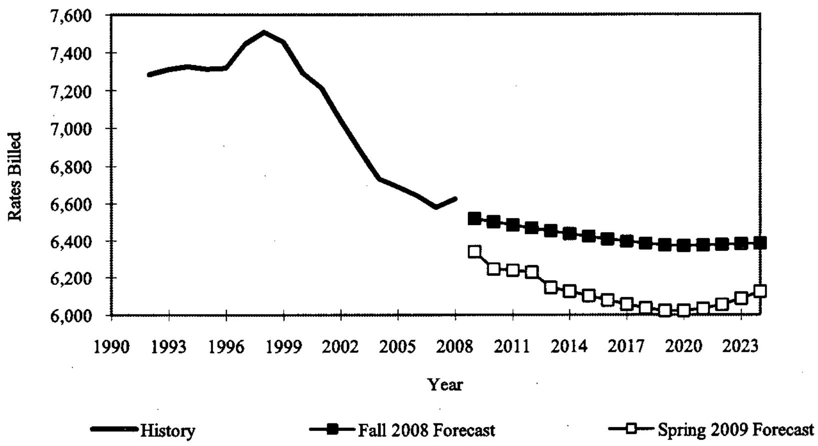
AVERAGE ANNUAL GROWTH

	Rates Billed Per Year	% Per Year
History (2003 to 2008)	-48	-5.9
History (1993 to 2008)	-48	-4.7
Spring 2009 Forecast (2008 to 2024)	-18	-3.3
Fall 2008 Forecast (2008 to 2024)	-22	-4.4

SPRING 2009 FORECAST / FALL 2008 FORECAST

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	Difference from Fall 2008 Rates Billed	%
2009	591	-84	-12.5	557	34	6.0
2010	536	-54	-9.2	504	32	6.4
2011	522	-15	-2.7	478	44	9.1
2012	503	-18	-3.5	453	50	11.1
2013	485	-19	-3.7	433	52	12.0
2014	469	-16	-3.2	417	52	12.5
2015	455	-14	-2.9	401	54	13.6
2016	443	-12	-2.7	388	55	14.2
2017	432	-11	-2.4	377	55	14.7
2018	424	-9	-2.0	367	57	15.4
2019	417	-7	-1.5	358	59	16.4
2020	412	-5	-1.3	352	60	17.0
2021	407	-5	-1.2	345	61	17.7
2022	402	-5	-1.2	339	63	18.5
2023	398	-3	-0.8	334	64	19.3
2024	395	-3	-0.9	329	66	20.0

Other Industrial Rates Billed



HISTORY

Year	Actual Rates Billed	Growth Rates Billed	%
1999	7,455	-52	-0.7
2000	7,293	-162	-2.2
2001	7,213	-81	-1.1
2002	7,040	-173	-2.4
2003	6,887	-153	-2.2
2004	6,733	-154	-2.2
2005	6,690	-43	-0.6
2006	6,644	-47	-0.7
2007	6,581	-63	-0.9
2008	6,626	45	0.7

AVERAGE ANNUAL GROWTH

	Rates Billed Per Year	% Per Year
History (2003 to 2008)	-52	-0.8
History (1993 to 2008)	-46	-0.7
Spring 2009 Forecast (2008 to 2024)	-31	-0.5
Fall 2008 Forecast (2008 to 2024)	-15	-0.2

SPRING 2009 FORECAST / FALL 2008 FORECAST

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	Difference from Fall 2008 Rates Billed	%
2009	6,342	-284	-4.3	6,521	-178	-2.7
2010	6,247	-95	-1.5	6,503	-256	-3.9
2011	6,240	-8	-0.1	6,486	-246	-3.8
2012	6,230	-10	-0.2	6,470	-240	-3.7
2013	6,146	-84	-1.3	6,454	-308	-4.8
2014	6,126	-20	-0.3	6,439	-313	-4.9
2015	6,102	-24	-0.4	6,424	-322	-5.0
2016	6,079	-23	-0.4	6,410	-331	-5.2
2017	6,056	-23	-0.4	6,397	-341	-5.3
2018	6,036	-20	-0.3	6,385	-349	-5.5
2019	6,023	-13	-0.2	6,376	-353	-5.5
2020	6,022	-1	0.0	6,372	-350	-5.5
2021	6,033	11	0.2	6,375	-342	-5.4
2022	6,055	22	0.4	6,379	-324	-5.1
2023	6,088	32	0.5	6,383	-295	-4.6
2024	6,124	36	0.6	6,386	-262	-4.1

System Peaks

The Summer peak forecast represents the maximum coincidental demand during the summer season on the Duke Energy Carolinas system. It includes all Retail classes, Schedule 10A Resale, and total resource needs for Catawba Joint Owners plus the contribution to total peak associated with Nantahala Power and Light. The peak forecast excludes the demand portion of contract sales to other utilities, and sales to Seneca and Greenwood. It is expressed in MW at the point of generation and includes losses.

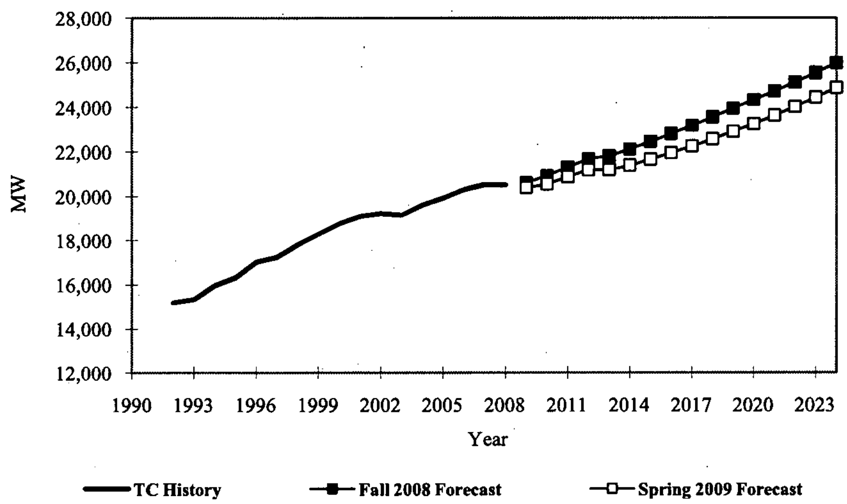
Adjustments were made to the peak forecasts for the Fall 2008 Forecasts and the Spring 2009 Forecasts to account for the expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007. **These peak forecasts do not include adjustments for proposed energy efficiency programs.** Additional adjustments to the Spring 2009 Forecast include peak reductions associated with price increases due to a Carbon Tax starting in 2013 and peak additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011.

The last Summer peak occurred on Monday, June 9, 2008 at 4 p.m. An actual peak of 20,517 MW was achieved at a time when the temperature was 98 degrees (for the Spring 2009 Forecast the expected temperature at the time of summer peak is 94 degrees).

Growth Forecasts

The new forecast projects an incremental growth of 272 MW or 1.2% per year for 2008-2024. The previous forecast growth was 340 MW or 1.5% per year for 2008-2024.

System Summer MW



HISTORY

Year	Weather Normalized MW	Growth MW	Growth %
1999	18,292	479	2.7
2000	18,780	488	2.7
2001	19,111	331	1.8
2002	19,238	127	0.7
2003	19,159	-79	-0.4
2004	19,614	455	2.4
2005	19,936	322	1.6
2006	20,314	378	1.9
2007	20,535	221	1.1
2008	20,522	-13	-0.1

AVERAGE ANNUAL GROWTH

	MW Per Year	% Per Year
History (2003 to 2008)	273	1.4
History (1993 to 2008)	346	2.0
Spring 2009 Forecast (2008 to 2024)	272	1.2
Fall 2008 Forecast (2008 to 2024)	340	1.5

SPRING 2009 FORECAST / FALL 2008 FORECAST

Year	MW	Growth MW	Growth %	Fall 2008 MW	Difference from Fall 2008 MW	Difference from Fall 2008 %
2009	20,398	-124	-0.6	20,606	-208	-1.0
2010	20,563	165	0.8	20,917	-353	-1.7
2011	20,868	305	1.5	21,303	-435	-2.0
2012	21,184	316	1.5	21,668	-485	-2.2
2013	21,196	13	0.1	21,788	-592	-2.7
2014	21,384	188	0.9	22,102	-718	-3.2
2015	21,648	264	1.2	22,442	-795	-3.5
2016	21,938	290	1.3	22,797	-859	-3.8
2017	22,234	296	1.3	23,165	-931	-4.0
2018	22,560	326	1.5	23,545	-985	-4.2
2019	22,899	339	1.5	23,942	-1,044	-4.4
2020	23,243	345	1.5	24,333	-1,089	-4.5
2021	23,622	379	1.6	24,720	-1,098	-4.4
2022	24,018	395	1.7	25,118	-1,101	-4.4
2023	24,439	421	1.8	25,533	-1,094	-4.3
2024	24,876	437	1.8	25,968	-1,092	-4.2

The Winter peak forecast represents the maximum coincidental demand during the winter season on the Duke Energy Carolinas' system. It includes all Retail classes, Schedule 10A Resale, and total resource needs for Catawba Joint Owners plus the contribution to total peak associated with Nantahala Power and Light. The peak forecast excludes the demand portion of contract sales to other utilities, and sales to Seneca and Greenwood. It is expressed in MW at the point of generation and includes losses.

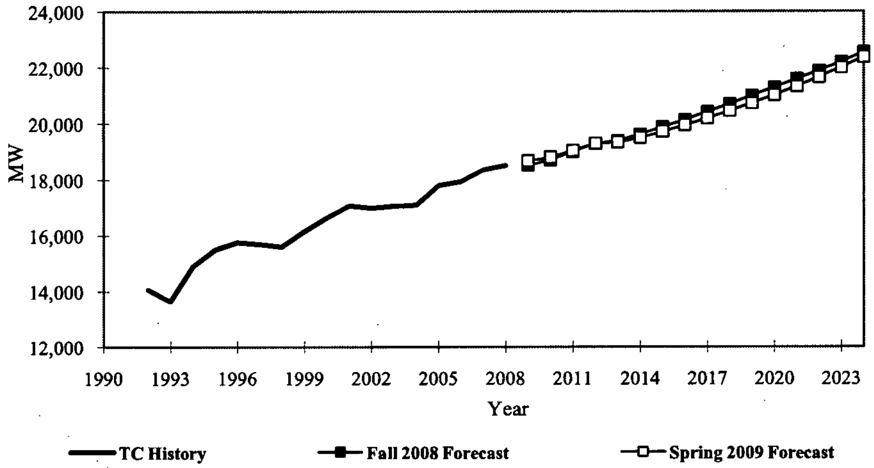
Adjustments were made to the peak forecasts for the Fall 2008 Forecasts and the Spring 2009 Forecasts to account for the expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007. **These peak forecasts do not include adjustments for proposed energy efficiency programs.** Additional adjustments to the Spring 2009 Forecast include peak reductions associated with price increases due to a Carbon Tax starting in 2013 and peak additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011.

The last Winter peak occurred on Thursday, February 5, 2009 at 8 a.m. with an actual peak of 19,122 MW. This was achieved at a time when the temperature was 18 degrees (for the Spring 2009 Forecast the expected temperature at the time of winter peak is 18 degrees).

Growth Forecasts

The new Forecast projects an incremental growth of 241 MW or 1.2% per year from 2008-2024. The previous forecast growth was 251 MW or 1.2% per year from 2008-2024.

System Winter MW



HISTORY

Year	Weather Normalized MW	Growth MW	Growth %
1999	16,150	546	3.5
2000	16,631	481	3.0
2001	17,078	447	2.7
2002	17,000	-78	-0.5
2003	17,062	62	0.4
2004	17,102	40	0.2
2005	17,806	703	4.1
2006	17,943	137	0.8
2007	18,366	423	2.4
2008	18,528	162	0.9

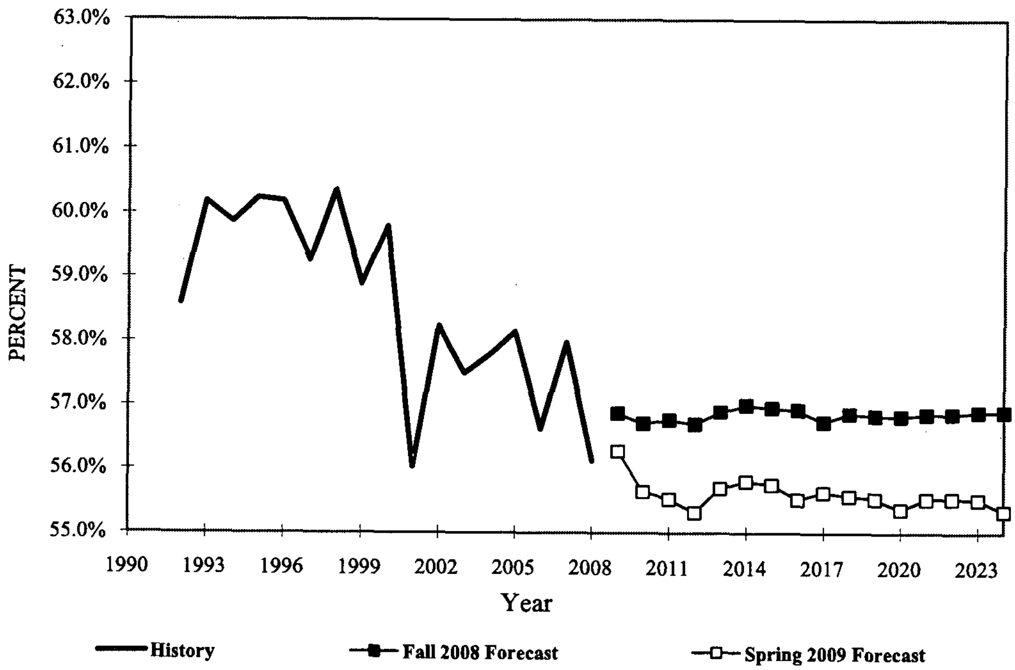
AVERAGE ANNUAL GROWTH

	MW Per Year	% Per Year
History (2003 to 2008)	293	1.7
History (1993 to 2008)	325	2.1
Spring 2009 Forecast (2008 to 2024)	241	1.2
Fall 2008 Forecast (2008 to 2024)	251	1.2

SPRING 2009 FORECAST / FALL 2008 FORECAST

Year	MW	Growth MW	Growth %	Fall 2008 MW	Difference from Fall 2008 MW	Difference from Fall 2008 %
2009	18,686	158	0.9	18,535	151	0.8
2010	18,816	130	0.7	18,733	83	0.4
2011	19,051	235	1.2	19,029	22	0.1
2012	19,302	251	1.3	19,299	3	0.0
2013	19,346	44	0.2	19,401	-56	-0.3
2014	19,512	167	0.9	19,631	-119	-0.6
2015	19,725	212	1.1	19,879	-154	-0.8
2016	19,956	232	1.2	20,141	-185	-0.9
2017	20,195	239	1.2	20,414	-219	-1.1
2018	20,458	263	1.3	20,698	-240	-1.2
2019	20,733	276	1.3	20,998	-264	-1.3
2020	21,017	284	1.4	21,293	-276	-1.3
2021	21,328	311	1.5	21,589	-260	-1.2
2022	21,658	330	1.5	21,891	-233	-1.1
2023	22,010	352	1.6	22,211	-201	-0.9
2024	22,380	369	1.7	22,552	-172	-0.8

The system load factor represents the relationship between annual energy and the maximum demand for the Duke Energy Carolinas' system. It is measured at generation level and excludes off-system sales and peaks.



Load Factor

APPENDIX C: EXISTING ENERGY EFFICIENCY (EE) AND DEMAND-SIDE MANAGEMENT (DSM) PROGRAMS

The following describes the existing EE and DSM programs offered by Duke Energy Carolinas. The tables at the end of this appendix list the existing DSM projection if the programs were to be continued and activation history.

<u>Current Energy Efficiency and Demand-Side Management Programs</u>

The following demand response programs are designed to provide a source of interruptible capacity to Duke Energy Carolinas:

Demand Response – Load Control Curtailment Programs

Residential Air Conditioning Direct Load Control
Participants receive billing credits during the billing months of July through October in exchange for allowing Duke Energy Carolinas the right to interrupt electric service to their central air conditioning systems.

This program will be replaced with PowerManager once an order is received from the NCUC.

Demand Response – Interruptible Programs

Interruptible Power Service
Participants agree contractually to reduce their electrical loads to specified levels upon request by Duke Energy Carolinas. If customers fail to do so during an interruption, they receive a penalty for the increment of demand exceeding the specified level.

Standby Generator Control
Participants agree contractually to transfer electrical loads from the Duke Energy Carolinas source to their standby generators upon request by Duke Energy Carolinas. The generators in this program do not operate in parallel with the Duke Energy Carolinas system and therefore, cannot "backfeed" (i.e., export power) into the Duke Energy Carolinas system. Participating customers receive payments for capacity and/or energy, based on the amount of capacity and/or energy transferred to their generators.

New Demand Response Programs

Power Manager
Power Manager is a residential load-control program. Participants receive billing credits during the billing months of July through October in exchange for allowing Duke Energy Carolinas the right to cycle their central air conditioning systems and, additionally, to interrupt the central air conditioning when the Company has capacity needs.

Information about the Power Manager program will be provided in bill inserts and on

Duke Energy Carolinas' Web site, but the program will not be actively marketed until two-way communication is available.

PowerShare®

PowerShare® is a non-residential curtailable program consisting of three options, an Emergency Option for curtailable load, an Emergency Option for load curtailment using on-site generators, and a Voluntary Option. The Emergency Option customers will receive capacity credits monthly based on the amount of load they agree to curtail during utility-initiated emergency events. Customers enrolled in the Emergency Option may also be enrolled in the Voluntary Option and eligible to earn additional credits. Voluntary Option customers will be notified of pending emergency or economic events and can log on to a Web site to view a posted energy price for that particular event. Customers will then have the option to nominate load for the event and will be paid the posted energy credit for load curtailed.

Demand Response – Time of Use Programs

Residential Time-of-Use

This category of rates for residential customers incorporates differential seasonal and time-of-day pricing that encourages customers to shift electricity usage from on-peak time periods to off-peak periods. In addition, there is a Residential Water Heating rate for off-peak water heating electricity use.

General Service and Industrial Time-of-Use

This category of rates for general service and industrial customers incorporates differential seasonal and time-of-day pricing that encourages customers to use less electricity during on-peak time periods and more during off-peak periods.

Hourly Pricing for Incremental Load

This category of rates for general service and industrial customers incorporates prices that reflect Duke Energy Carolinas' estimation of hourly marginal costs. In addition, a portion of the customer's bill is calculated under their embedded-cost rate. Customers on this rate can choose to modify their usage depending on hourly prices.

Conservation Programs

Residential Energy Star® Rates

This rate promotes the development of homes that are significantly more energy-efficient than a standard home. Homes are certified when they meet the standards set by the U.S. EPA and the U.S. Department of Energy (DOE). To earn the symbol, a home must be at least 30 percent more efficient than the national Model Energy Code for homes, or 15 percent more efficient than the state energy code, whichever is more rigorous. Independent third-party inspectors test the homes to ensure they meet the standards to receive the Energy Star® symbol. The independent home inspection is the responsibility of the homeowner or builder. Electric space heating and/or electric domestic water heating are not required.

Residential Energy Assessments

This program assists residential customers in assessing their energy usage and provides recommendations for more efficient use of energy in their homes. The program also helps identify those customers who could benefit most by investing in new demand-side management measures, undertaking more energy-efficient practices and participating in Duke Energy Carolinas programs. The types of available energy assessments and demand-side management products are as follows:

- Mail-in Analysis. The customer provides information about their home, number of occupants, equipment, and energy usage on a mailed energy profile survey, from which Duke Energy Carolinas will perform an energy use analysis and provide a Personalized Home Energy Report including specific energy-saving recommendations.
- Online Analysis. The customer provides information about their home, number of occupants, energy usage and equipment through an online energy profile survey. Duke Energy Carolinas will provide an Online Home Energy Audit including specific energy-saving recommendations.
- On-site Audit and Analysis. Duke Energy Carolinas will perform one on-site assessment of an owner-occupied home and its energy efficiency-related features during the life of this program.

Smart $aver® for Residential Customers

The Smart $aver® Program provides incentives to residential customers who purchase energy-efficient equipment. The program has two components – compact fluorescent light bulbs and high-efficiency air conditioning equipment.

This residential compact fluorescent light bulbs (CFLs) incentive program provides market incentives to customers and market support to retailers to promote use of CFLs. Special incentives to buyers and in-store support will increase demand for the products, spur store participation, and increase availability of CFLs to customers. Part of this program is to educate customers on the advantages (functionality and savings) of CFLs so that they will continue to purchase these bulbs in the future when no direct incentive is available.

The residential air conditioning program provides incentives to customers, builders, and heating contractors (HVAC dealers) to promote the use of high-efficiency air conditioners and heat pumps with electronically-commutated fan motors (ECM). The program is designed to increase the efficiency of air conditioning systems in new homes and for replacements in existing homes.

Low Income Services

The purpose of this program is to assist low income residential customers with demand-side management measures to reduce energy usage through energy efficiency kits or through assistance in the cost of equipment or weatherization measures.

Energy Efficiency Education Program for Schools
The purpose of this program is to educate students about sources of energy and energy efficiency in homes and schools through a curriculum provided to public and private schools. This curriculum includes lesson plans, energy efficiency materials, and energy audits.

Non-Residential Energy Assessments
The purpose of this program is to assist non-residential customers in assessing their energy usage and to provide recommendations for more efficient use of energy. The program also helps identify those customers who could benefit from other Duke Energy Carolinas DSM non-residential programs.

The types of available energy assessments are as follows:

- Online Analysis. The customer provides information about its facility. Duke Energy Carolinas will provide a report including energy-saving recommendations.
- Telephone Interview Analysis. The customer provides information to Duke Energy Carolinas through a telephone interview, after which billing data, and, if available, load profile data, will be analyzed. Duke Energy Carolinas will provide a detailed energy analysis report with an efficiency assessment along with recommendations for energy-efficiency improvements. A 12-month usage history may be required to perform this analysis.
- On-site Audit and Analysis. For customers who have completed either an Online Analysis or a Telephone Interview Analysis, Duke Energy Carolinas will cover 50% of the costs of an on-site assessment. Duke Energy Carolinas will provide a detailed energy analysis report with an efficiency assessment along with recommendations, tailored to the customer's facility and operation, for energy efficiency improvements. The Company reserves the right to limit the number of off-site assessments for customers who have multiple facilities on the Duke Energy Carolinas system. Duke Energy Carolinas may provide additional engineering and analysis, if requested, and the customer agrees to pay the full cost of the additional assessment.

Smart $aver® for Non-Residential Customers
The purpose of this program is to encourage the installation of high-efficiency equipment in new and existing non-residential establishments. The program provides incentive payments to offset a portion of the higher cost of energy-efficient equipment. The following types of equipment are eligible for incentives: high-efficiency lighting, high-efficiency air conditioning equipment, high-efficiency motors, and high-efficiency pumps. Customer incentives may be paid for other high-efficiency equipment as determined by the Company to be evaluated on a case-by-case basis.

APPENDIX D: SUPPLY-SIDE OPTIONS REFERENCED IN THE PLAN

Supply-Side Options

Supply-side options considered in the IRP are subjected to an economic screening process to determine the most cost-effective technologies to be passed along for consideration in the quantitative analysis phase of the process. Generally, conventional, demonstrated, and emerging technologies must pass a cost screen, a commercial availability screen, and a technical feasibility screen to be considered for further evaluation.

The data for each technology being screened is based on research and information from several sources. In addition to internal sources, bids from the Renewable RFP, the Electric Power Research Institute (EPRI) Technology Assessment Guide (TAG®), and studies performed by and/or information gathered from vendors and/or entities were used in the estimation of capital, operating costs, and operational characteristics for the supply-side alternatives. The EPRI information along with any information or estimates from external studies is not site-specific, but generally reflects the costs and operating parameters for installation in the Southeast.

Finally, every effort is made to ensure, as much as possible, that the cost and other parameters are current, on a common basis, and include similar scope across the technology types being screened. While this has always been important, keeping cost estimates across a variety of technology types consistent in today's construction material, manufactured equipment, and commodity markets is getting very difficult to maintain. As discussed in last year's filing, the rapidly escalating and de-escalating (as a result of current economic recession pressures) prices in these markets has continued often making cost estimates and other price/cost information out-of-date in as little as six months. In addition, vendor quotes once relied upon as being a good indicator of, or basis for, the cost of a generating project, may have lives as short as 30 days. This year two additional hydro based options are included, Jocassee Unit 5 and Coley Creek Pumped Storage. The estimated costs of these two options were based on dated vendor estimates and escalated to current times. As a result, if these options are selected, more rigorous cost estimate refinement will be necessary prior to any actual implementation steps.

From previous technical feasibility screening efforts, several additional technologies were eliminated from further consideration. A brief explanation of the technologies excluded and the logic for their exclusion follows:

- Coal-fired Circulating Fluidized Bed combustion is a conventional, commercially-proven technology in utility use. However, boiler size remains generally limited to 300-350 MW. In addition, the new source performance standards (NSPS) generally dictate that post-boiler clean-up equipment must be installed to meet the standards when burning coal, which effectively eliminates one of the advantages of this technology. Both of these issues cause it to be one of the higher-cost baseload alternatives available on a utility scale.

- Advanced Battery storage technologies remain relatively expensive and are generally suitable for small-scale emergency back-up and/or power quality applications with short-term duty cycles of three hours or less. In addition, the current energy storage capability is generally 100 MWh or less. Research, development, and demonstration continue, but this technology is generally not commercially available on a larger supply-side utility scale. Small-scale substation pilots are being studied to assist in increasing distribution system reliability.

- Fuel Cells, although originally envisioned as being a competitor for combustion turbines and central power plants, are now targeted to mostly distributed power generation systems. The size of the distributed generation applications ranges from a few kilowatts to tens of megawatts in the long-term. Fuel gas (hydrogen) purity, cost and performance issues have generally limited their application to niche markets and/or subsidized installations. While a medium level of research and development continues, this technology is not commercially available for utility-scale application.

Below is a listing of the technologies screened, placed into general Conventional and Demonstrated categories:

Conventional Technologies (technologies in common use):

<u>Base Load Technologies</u>
800 MW class Supercritical Coal (Greenfield)
1117 MW Nuclear units, AP1000 (priced as sets of 2)

<u>Peak / Intermediate Technologies</u>
160 MW Combustion Turbines – GE 7FA (priced as sets of 4)
500 MW Combined Cycle – GE 7FA (with duct firing capacity augmentation not included in 500 MW rating)
100 MW Jocassee Hydro Unit 5
6 x 350 MW Coley Creek Pumped Hydro Storage

Demonstrated Technologies (technologies commercial gernerall not in widespread use):

<u>Base Load Technologies</u>
630 MW class IGCC (Greenfield)

During 2007, in anticipation of the state of North Carolina passing RPS legislation, Duke Energy Carolinas issued an RFP for renewable resources. In addition to bids received during 2007, unsolicited renewable energy offers continue to be received during 2009.

The bids and other offers were of the following types:

- On-Shore Wind
- Biomass
  - o Biomass Woody Firing
  - o Poultry Waste Firing
  - o Hog Digester Biogas Firing
- Solar PV
- Landfill Gas

The analysis for the IRP utilized an average composite of the bids or offers of similar renewable types (solar, wind, etc.) to perform the renewables screening for this type since this was the most up-to-date information available.

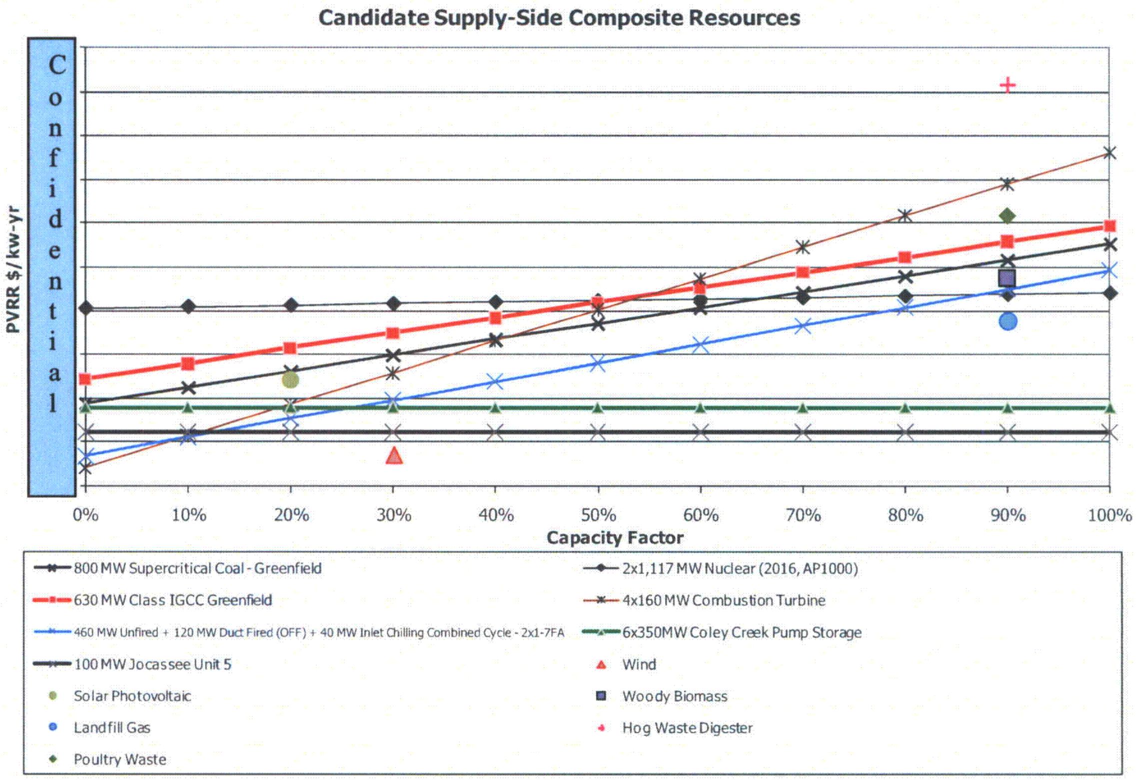
The screening includes the impacts of the traditional regulated emissions of SO_2 and NOx generally associated with the Clean Air Act Amendments of 1990, the recently overturned Clean Air Interstate Rule, and the 2002 North Carolina Clean Smokestacks Act along with consideration of The Dingle Boucher proposed CO_2 regulations and the N.C. Renewable Energy Portfolio Standard. These scenarios are discussed in more detail in Appendix A.

The following estimated Levelized Busbar Cost[9] chart provides an economic comparison of the technologies. Comparisons involving some renewable resources, particularly wind and solar resources, can be somewhat misleading because these resources do not contribute their full installed capacity at the time of the system peak[10] and generally have resource limited capacity factors. Since busbar charts attempt to levelize and compare costs on an installed kW basis, wind and solar resources appear to be more economic than they would be if the comparison was performed on a peak kW basis. In addition, because the costs utilized in the screening for renewable resources were generally based on "must take" bids at specified capacity factors, the chart shows a single point for each type of resource at the particular capacity factor specified. Also, the capacity (MW size) for each non-renewable technology represented is listed in the chart legends. The expected energy (MWh) at any given capacity factor (whether along a continuous line, or a specific point) may be determined by the following formula: Expected Energy (MWh) = 8,760 x Capacity (MW size) x Capacity Factor (%/100).

[9] While these estimated levelized busbar costs provide a reasonable basis for initial screening of technologies, simple busbar cost information has limitations. In isolation, busbar cost information has limited applicability in decision-making because it is highly dependent on the circumstances being considered. A complete analysis of feasible technologies must include consideration of the interdependence of the technologies within the context of Duke Energy Carolinas' existing generation portfolio.

[10] For purposes of this IRP, wind resources are assumed to contribute 15% of installed capacity at the time of peak and solar resources are assumed to contribute 50% of installed capacity at the time of peak.

Composite Busbar Chart - Higher Carbon Scenario



Appendix E: 2009 FERC Form 715

The 2009 FERC Form 715 filed April 2009 is confidential and filed under seal.

APPENDIX F: CROSS-REFERENCE OF IRP REQUIREMENTS

The following table cross-references IRP regulatory requirements for North Carolina and South Carolina, and identifies where those requirements are discussed in the Plan.

Requirement	Location	Reference	Updated
Forecast of Load, Supply-side Resources, and Demand-Side Resources.			
• 10 year history of customers & energy sales	Sect III	NC R8-60 h (i) 1(i)	Yes
• 15 year forecast w & w/o energy efficiency	Sect III	NC R8-60 h(i) 1(ii)	Yes
• Description of supply-side resources	Sect IV, App D	NC R8-60 h(i) 1(iii)	Yes
Generating Facilities			
• Existing Generation	Sect II	NC R8-60 h (i) 2(i)(a-f)	Yes
• Planned Generation	Sect III,	NC R8-60 h (i) 2(ii)(a-d)	Yes
• Non Utility Generation	~~App J~~	NC R8-60 h (i) 2(iii)	No
• Proposed Generation Units at Locations not known	Sect V		Yes
• Generating Units Projected to be Retired	Sect III		Yes
• Generating Units with plan for life extension	N/A		No
Reserve Margin	~~Sect III~~	NC R8-60 h (i) 3	No
Wholesale Contract for the Purchase and Sale of Power			
• Wholesale Purchase Power Contract	Sect II	NC R8-60 h (i) 4(i)	Yes
• Request for Proposal	Sect II	NC R8-60 h (i) 4(ii)	?
• Wholesale power sales contracts	Sect II	NC R8-60 h (i) 4(iii)	Yes
Transmission Facilities , planned & under construction	~~App G~~	NC R8-60 h (i) 5	No
Transmissions System Adequacy	~~Sect II~~		No
FERC Form 1 (pages 422-425)	~~App K~~		No
FERC Form 715	App E		Yes
Energy Efficiency and Demand Side Management			
• Existing Programs	Sect II, App C	NC R8-60 h (i) 6(i)	Yes
• Future Programs	Sect III	NC R8-60 h (i) 6(ii)	Yes
• Rejected Programs	~~App I~~	NC R8-60 h (i) 6(iii)	No
• Consumer Education Programs	~~App I~~	NC R8-60 h (i) 6(iv)	No
Assessment of Alternative Supply-Side Energy Resource			
• Current and Future Alternative Supply-Side	App D	NC R8-60 h (i) 7(i)	Yes
• Rejected Alternative Supply-Side Energy Resource	App D	NC R8-60 h (i) 7(ii)	Yes
Evaluation of Resource Options (Quantitative Analysis)	App A	NC R8-60 h (i) 8	Yes
Cost benefit analysis of each option Levelized Bus-bar Costs	App D	NC R8-60 h (i) 9	Yes
Other Information (economic development)	~~App L~~		No
Legislative and Regulatory Issues	Sect II		Yes
Supplier's Program for Meeting the Requirements Shown in its Forecast in an Economic and Reliable Manner, including EE and DSM and Supply-Side Options	Sec I,V, App A		Yes
Supplier's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service, and a description of the external, environmental and economic consequences of the plan to the extent practicable	Sec V, App A		Yes