The Duke Energy Carolinas Integrated Resource Plan (Annual Report)

September 1, 2011

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Integrated Resource Plan – abbreviations

Carbon Dioxide	CO_2
Central Electric Power Cooperative, Inc.	CEPCI
Certificate of Public Convenience and Necessity	CPCN
Clean Air Interstate Rule	CAIR
Clean Air Mercury Rule	CAMR
Coal Combustion Residuals	CCR
Combined Construction and Operating License	COL
Combined Cycle	CC
Combustion Turbines	CTs
Commercial Operation Date	COD
Compact Fluorescent Light bulbs	CFL
Cross State Air Pollution Rule	CSAPR
Demand Side Management	DSM
Direct Current	DC
Duke Energy Annual Plan	The Plan
Duke Energy Carolinas	DEC
Duke Energy Carolinas	The Company
Eastern Interconnection Planning Collaborative	EIPC
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 Desulphurization	FGD
General Electric	GE
Greenhouse Gas	GHG
Heating, Ventilation and Air Conditioning	HVAC
Information Collection Request	ICR
Integrated Gasification Combined Cycle	IGCC
Integrated Resource Plan	IRP
Interruptible Service	IS
Load, Capacity, and Reserve Margin Table	LCR Table
Maximum Achievable Control Technology	MACT
Nantahala Power & Light	NP&L
National Ambient Air Quality Standards	NAAQS
National Pollutant Discharge Elimination System	NPDES
NC Department of Environment and Natural Resources	NCDENR
NC Green Power	NCGP
New Source Performance Standard	NSPS
Nitrogen Oxide	NO_x
North American Electric Reliability Corp	NERC
North Carolina	NC
North Carolina Clean Smokestacks Act	NCCSA
North Carolina Division of Air Quality	NCDAQ
North Carolina Electric Membership Corporation	NCEMC
North Carolina Municipal Power Agency #1	NCMPA1

Integrated Resource Plan – abbreviations

North Carolina Utilities Commission	NCUC
Notice of Proposed Rulemaking	NOPR
Nuclear Regulatory Commission	NRC
Palmetto Clean Energy	PaCE
Parts Per Billion	PPB
Photovoltaic	PV
Piedmont Municipal Power Agency	PMPA
Plug-In Electric Vehicles	PEV
Power Delivery	PD
Present Value Revenue Requirements	PVRR
Prevention of Significant Deterioration	PSD
Public Service Commission of South Carolina	PSC
Purchase Power Agreement	PPA
Qualifying Facility	QF
Rate Impact Measure	RIM
Renewable Energy and Energy Efficiency Portfolio Standard	REPS
Renewable Energy Certificates	REC
Renewable Portfolio Standard	RPS
Request for Proposal	RFP
Resource Conservation Recovery Act	RCRA
Saluda River Electric Cooperative	SR
Selective Catalytic Reduction	SCR
SERC Reliability Corporation	SERC
South Carolina	SC
Southeastern Power Administration	SEPA
Standby Generation	SG
State Implementation Plan	SIP
Sulfur Dioxide	SO_2
Technology Assessment Guide	TAG
Total Resource Cost	TRC
United States Department of Energy	USDOE
Utility Cost Test	UCT
Virginia/Carolinas	VACAR
Volt Ampere Reactive	VAR
Western Carolina University	WCU

FORWARD

This Integrated Resource Plan (IRP) is Duke Energy Carolinas' biennial report under the revised North Carolina Utilities Commission (NCUC) Rule R8-60. A cross reference identifying where each regulatory requirement can be found within this IRP is provided in Appendix K.

NCUC Rule R8-60 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 NCUC 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 2010 IRP are provided in the Duke Energy Carolinas 2011 IRP Annual Report.

a) 15-year forecast
b) Short term action plan
c) Existing Generation Plants in Service
d) Renewable Energy Initiatives
e) Energy Efficiency and Demand Side Management peak and energy impacts
f) Wholesale Power Sales Commitments
g) Legislative and Regulatory Issues
h) Fundamental fuel, energy, and emission allowance prices
i) Generating units projected to be retired
j) Load and Resource Balance
k) Changes to existing and future resources
l) Overall planning process conclusions incorporating a) through l) above
m) Detailed information pertaining to the requirement that Duke Energy Carolinas implement a Greenhouse Gas Reduction Plan (Greenhouse Plan) as a stipulation to the North Carolina Department of Air Quality (NCDAQ) Air Permit for Cliffside Unit 6. This information can be found in Appendix J.

1. EXECUTIVE SUMMARY

Duke Energy Carolinas, LLC (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 IRP.

Consistent with its responsibility to meet customer energy needs in a way that is affordable, reliable, and clean, 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 emergence and development of new technologies, and regional economic development considerations are also important factors to consider as long-term decisions are made regarding new resources.

Company management uses all of these qualitative perspectives in conjunction with its quantitative analyses to ensure that Duke Energy Carolinas will meet near-term and long-term customer needs, while maintaining the operational flexibility to adjust to evolving economic, environmental, and operating circumstances in the future. As a result, the Company's plan is designed to be robust under many possible future scenarios.

The notable changes from the 2010 IRP to the 2011 IRP are the projected increase in peak generation need in 2015 due to increased load projections, updated assumptions regarding the energy impacts of Compact Fluorescent Lights (CFLs) and lower projected capacity impacts from Demand Side Management programs, as well as changes in the projected compliance portfolio relating to the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS). The overall impact of these factors results in a resource need of 790 MWs in 2015.

The increased load projection is driven primarily by an increase in the projected demand from the industrial sector. The 2011 load forecast also incorporates a change in methodology related to the projected load impacts of CFLs in the residential and commercial sectors. These methodology changes included a change in the factors utilized for the residential sector and no incremental CFL impact, beyond what's reflected in the historical sales trends.

[1] Throughout this IRP, the term EE will denote conservation programs while the term DSM will denote Demand Response programs, consistent with the language of N.C. Gen. Stat. 62-133.8 and 133.9.

The lower projections of DSM impacts were driven primarily by the anticipated impact of the proposed Environmental Protection Agency (EPA) Reciprocating Internal Combustion Engine (RICE) rule, which limits hours of non-emergency operation of emergency generators located at commercial and industrial facilities. This rule, as proposed, is projected to significantly impact Duke Energy Carolinas' PowerShare program. The 2011 DSM projections were updated to reflect the manner in which the RICE rule will materially limit participation in the PowerShare program by our customers. The projected reduction in DSM impacts results in a corresponding increase in our customers' capacity needs.

Additionally, in the 2011 IRP, the analysis reflects a shift in the Company's strategy for NC REPS compliance over the long term. In the 2010 IRP, the long term NC REPS compliance strategy relied primarily on biomass resources during the first 10 years and then shifted to wind resources for the remainder of the planning period. Based upon recent proposals for wind purchased power agreements and the continuing federal regulatory uncertainty regarding treatment of biomass generation, for the 2011 IRP, the Company has adopted a strategy with increased reliance on wind resources during the first 10 years and a shift to biomass resources for the remainder of the planning period. This change in strategy impacts the 2015 peak resource requirement because only a small percentage of the rated capacity for wind resources can be counted toward meeting the Company's system peak, as opposed to the more reliable expected system peak contribution from biomass resources.

The 2011 IRP continues to reflect the retirement of Duke Energy Carolinas' older coal units without flue gas desulfurization (FGDs) facilities (also known as SO_2 scrubbers). These planned retirements are driven primary by the recently proposed EPA Mercury Utility Maximum Achievable Control Technology (MACT) rule. The MACT rule is expected to be finalized in November 2011, with required control technologies to be installed by January 1, 2015. Other emerging environmental regulations that also are expected to impact the retirement decisions relating to the Company's existing coal fleet include the Coal Combustion Residuals (CCR) rule, Cross State Air Pollution Rule (CSAPR), Sulfur Dioxide (SO_2) and Ozone National Ambient Air Quality standards (NAAQS). The Company has developed the 2011 IRP based on expectations of how these rules will be ultimately established.

Greenhouse gas (GHG) regulations or legislation also have the potential to impact the Company's resource plans. From 2007 to 2009, multiple GHG cap and trade bills were introduced in Congress. More recently, Clean Energy Standards (CES) have been discussed in lieu of cap and trade legislation or regulation. A CES would require that a certain percentage (e.g. 10% in 2015 escalating up to 30% in 2030) of a utility's retail sales be met with combined cycle (CC) natural gas, nuclear, EE, or renewable energy. At present, the Company does not anticipate that Congress will consider GHG legislation through the end of

2012. Beyond 2012, the prospects for possible enactment of any legislation mandating reductions in GHG emissions are highly uncertain. Although the Company continues to believe that Congress will eventually adopt some form of mandatory GHG emission reduction or Clean Energy legislation, the timing and form of any such legislation remains highly uncertain. In the absence of federal GHG or Clean Energy legislation, the EPA continues to pursue GHG regulations on new and existing units. EPA has announced its plans to issue a proposed regulation for fossil-fired generating units in 2011. The impacts of future EPA regulations are uncertain at this time; however the Company believes that it is prudent to continue to plan for a carbon-constrained future. To address this uncertainty, the Company has evaluated a range of CO_2 prices, in addition to potential Clean Energy legislation.

Planning Process Results

Duke Energy Carolinas' generation resource needs increase significantly over the 20-year planning horizon of the 2011 IRP. Cliffside Unit 6 and the Buck and Dan River natural gas CC units, along with the Company's EE and DSM programs, will fulfill these needs through 2014. Beginning in 2015, the Company has a capacity need of 790 MWs to meet its projected load requirements along with a 17% reserve margin. Even if the Company fully realizes its goals for EE and DSM, the resource need grows to approximately 7,030 MWs by 2031. This projected capacity need is higher than that reflected in the 2010 Duke Energy Carolinas IRP due primarily to higher load projections and the other reasons listed above.

The 2011 Duke Energy Carolinas IRP outlines the Company's options and plans for meeting the projected long-term needs. The factors that influence resource needs are:

- Future load growth projections;
- The amount of EE and DSM that can be achieved;
- Resources needed to meet the NC REPS requirement;
- Reductions in existing resources, for example, due to unit retirements and expiration of purchased power agreements (PPA); and
- Meeting the Company's 17% target planning reserve margin over the 20-year horizon.

A key purpose of the IRP is to provide the Company's 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 over time.

In the short-term, the 2011 IRP analysis results indicate the need for peaking and intermediate resources as early as 2015 and 2016 and at various points throughout the study period. The results also show the need for new baseload facilities as early as 2018.

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

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

Both DSM and EE programs play important roles in the Company's development of a balanced, cost-effective and environmentally responsible resource portfolio. Renewable generation options are also necessary to meet NC REPS enacted in 2007. These resources will be incorporated more broadly into the Company's resource portfolio to the extent they become more cost-effective in comparison with traditional supply-side resources and with consideration of other qualitative issues such as their intermittency and relative contribution to meeting peak capacity needs. Energy savings resulting from EE programs may also be used to meet, in part, the Company's REPS obligations. The Company's REPS Compliance Plan is being filed concurrently with the 2011 IRP, pursuant to the requirements of NCUC Rule R8-67.

The 2011 IRP also includes the Company's plan for meeting the requirements set forth in the Cliffside Unit 6 NCDAQ Air Permit (Cliffside Air Permit). The Cliffside Air Permit requires the Company take specific actions to render Cliffside Unit 6 carbon neutral by 2018. In the context of the 2011 IRP, the Company is seeking approval from the NCUC of the proposed plan as required by the Cliffside Air Permit.

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

The Company's Short Term Action Plan, which identifies accomplishments in the past year and actions to be taken over the next five years, are summarized below:

- Take actions to ensure capacity needs beginning in 2015 are met. In addition to seeking to meet the Company's DSM and EE goals and meeting the Company's REPS requirements, actions to secure additional capacity may include purchased power or generating capacity or Company-owned generation. In addition, the Company's capacity needs will be evaluated in light of the combined needs and resources of Duke Energy Carolinas and Progress Energy Carolinas upon consummation of the merger between Duke Energy and Progress Energy, Inc. (Progress Energy).

- Continue to evaluate and plan for the retirement of older coal generation. Buck Steam Station Units 3 and 4 were retired in May 2011. Cliffside Units 1 through 4 and Dan River Units 1 and 2 are required to be retired in advance of the commercial operation of new generation at those locations. The timing of the retirements of the remaining un-scrubbed coal units in the 2015 timeframe will continue to be assessed as emerging federal environmental regulations are finalized over the coming years.

- Continue to execute the Company's EE and DSM plan, which includes a diverse portfolio of DSM and EE programs, and continue on-going collaborative work to develop and implement additional cost-effective EE and DSM products and services. Approved and planned programs and pilots include:

- The Residential Retrofit program, which was approved in North Carolina in Docket E-7, Sub 952 on January 25, 2011 and in South Carolina in Docket 2010-51-E on February 24, 2010.

- The Home Energy Comparison Report pilot, which was approved by the Public Service Commission of South Carolina (PSC) in Docket 2010-50-E on March 24, 2010, and is currently only offered in South Carolina.

- The Smart Energy Now (SEN) pilot program, which was approved by the NCUC in Docket E-7, Sub 961 on February 14, 2011, and is currently only offered in North Carolina.

- Subject to approval by the NCUC and/or PSC, Duke Energy Carolinas plans to offer the following full program additions to its portfolio in the next year: Additional Smart $aver® Measures, Direct Install Low Income and Appliance Recycling.

- The Company is also considering a Home Energy Manager (HEM) Lite pilot program.

- Continue construction of the 825 MW Cliffside Unit 6, with the objective of bringing this additional capacity online by 2012 at the existing Cliffside Steam Station. As of June 2011, the project was over 80% complete.

- Continue construction of new combined-cycle natural gas generation at Buck and Dan River Steam Stations.

  - Buck CC Project: Continue construction of the 620 MW Buck CC project, with the objective of bringing this additional capacity on line by the end of 2011. As of July 2011, project was over 90% complete.

  - Dan River CC Project: Construction has begun on the 620 MW Dan River CC project is scheduled to be operational by the end of 2011. As of July 2011, the project was over 50% complete.

- Pursue the conversion of Lee Steam Station from coal to natural gas fuel. Lee Steam Station is reflected in the 2011 Duke Energy Carolinas IRP as a retired coal station in the fourth quarter of 2014 and converted to natural gas by January 1, 2015. Preliminary engineering has been completed and more detailed project development and regulatory efforts are ongoing.

- Continue to pursue the option for new nuclear generating capacity in the 2015 to 2025 timeframe.

  - The Company filed an application with the NRC for a COL in December 2007. The Company plans to continue to support the NRC evaluation of the COL.

  - The Company continues to pursue project development approvals and to evaluate the optimal time to file the Certificate of Environmental Compatibility and Public Convenience and Necessity (CPCN) in South Carolina, as well as other relevant regulatory approvals.

  - The Company will continue to pursue available federal, state and local tax incentives and favorable financing options at the federal and state level.

  - The Company will continue to assess opportunities to benefit from economies of scale and risk reduction in new resource decisions by considering the prospects for joint ownership and/or sales agreements for new nuclear generation resources.

- Continue to evaluate market options for renewable generation and enter into contracts as appropriate. PPAs have been signed with developers of solar photovoltaic (PV), landfill gas, wind, and thermal resources. Additionally, renewable energy certificate (REC) purchase agreements have been executed for purchases of unbundled RECs from wind, solar PV, solar thermal and hydroelectric facilities.

- Continue to investigate the future environmental control requirements and resulting operational impacts associated with the Mercury MACT rule, the CCR rule, the CSAPR rule and the new Ozone NAAQS and SO_2.

- Continue to pursue existing and potential opportunities with wholesale power sales agreements within the Duke Energy Balancing Authority Area.

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

2. SYSTEM OVERVIEW, OBJECTIVES, AND PROCESS

A. SYSTEM 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. Recent historical values for the number of customers and sales of electricity by customer groupings may be found in Tables 3.B and 3.C in Chapter 3.

Duke Energy Carolinas currently meets energy demand, in part, by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:

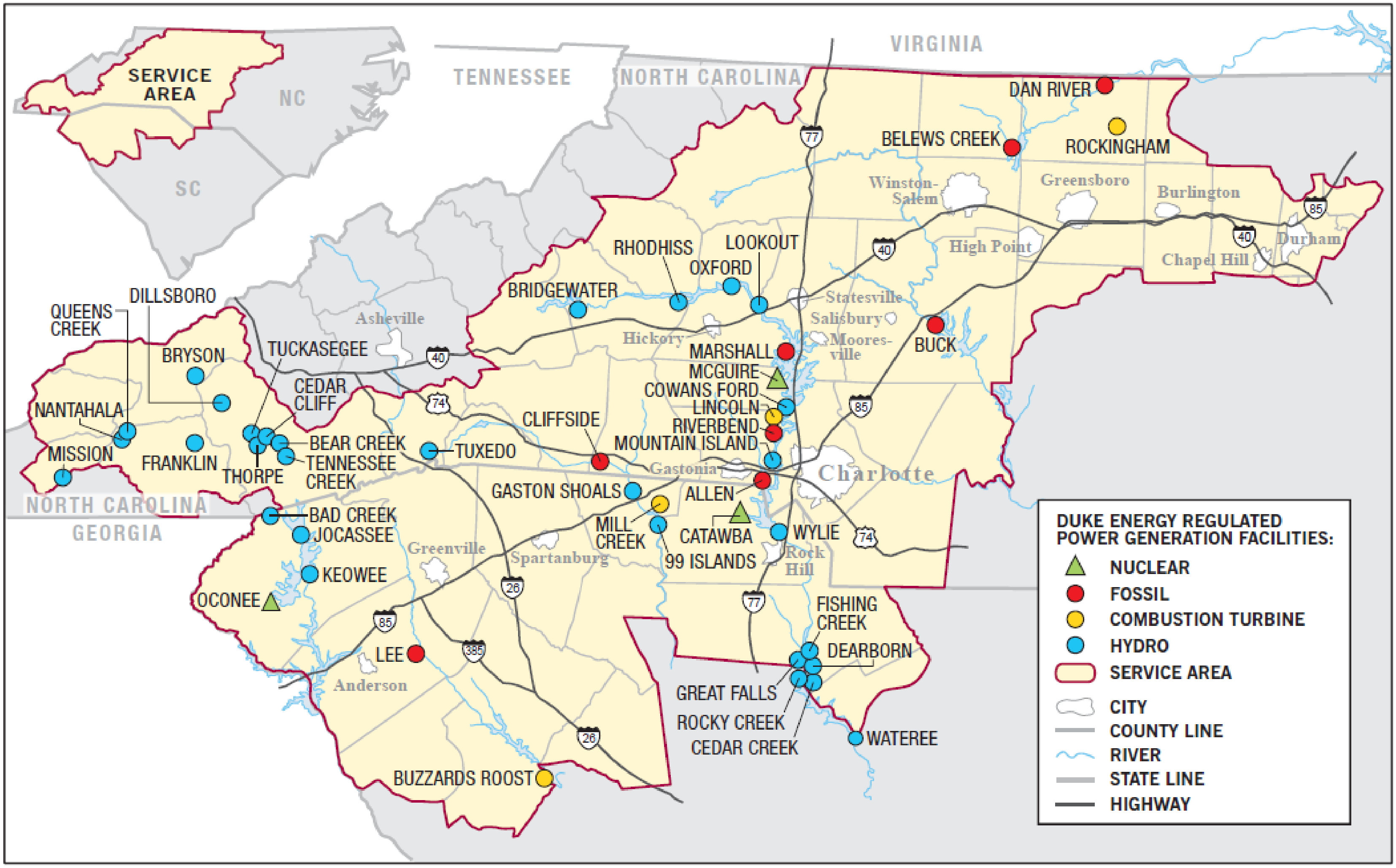
- Three nuclear generating stations with a combined net capacity of 6,996 MW (including all of Catawba Nuclear Station);
- Eight coal-fired stations with a combined capacity of 7,535 MW;
- 30 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 3,209 MW; and
- Eight combustion turbine stations with a combined capacity of 3,120 MW.

Duke Energy Carolinas' power delivery system consists of approximately 95,000 miles of distribution lines and 13,000 miles of transmission lines. The transmission system is directly connected to all of the utilities that surround the Duke Energy Carolinas service area. There are 35 circuits connecting with eight different utilities: Progress Energy Carolinas, American Electric Power, Tennessee Valley Authority, Southern Company, Yadkin, Southeastern Power Administration (SEPA), South Carolina Electric and Gas, and Santee Cooper. These interconnections allow utilities to work together to provide an additional level of reliability. The strength of the system is also reinforced through coordination with other electric service providers in the Virginia-Carolinas (VACAR) subregion, SERC Reliability Corporation (SERC) (formerly Southeastern Electric Reliability Council), and North American Electric Reliability Corporation (NERC).

The map on the following page provides a high-level view of the Duke Energy Carolinas system.

Duke Energy

Duke Energy – Carolinas Power Generation Facilities



B. OBJECTIVES

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 2011 IRP.

The purpose of this IRP is to outline a robust strategy to furnish electric energy services to Duke Energy Carolinas customers in a reliable, efficient, and economic manner while factoring in the uncertainty of the current environment.

The planning process itself must be dynamic and constantly adaptable to changing conditions. The IRP presented herein represents the most robust and economic outcome based upon the Company's analyses under various assumptions and sensitivities. Due to the uncertainty of the current environment including regulatory, economic, environmental and operating circumstances, Duke Energy Carolinas has performed sensitivity analysis as part of this IRP to account for these uncertainties. As the environment continues to evolve, Duke Energy Carolinas will continue to monitor and make adjustments as necessary and practical to reflect improved information and changing circumstances.

Duke Energy Carolinas' long-term planning objective is to employ a flexible planning process and pursue a resource strategy that considers the costs and benefits to all stakeholders (customers, shareholders, employees, suppliers, and community). At times, this involves striking a balance between competing objectives. The major objectives of the plan presented in this filing are:

- Provide adequate, reliable, and economic service to customers in an uncertain environment.
- Maintain the flexibility and ability to alter the plan in the future as circumstances change.
- Choose a near-term plan that is robust over a wide variety of possible futures.
- Minimize risks with the development of a balanced portfolio.

C. PLANNING PROCESS

The development of the IRP is a multi-step process over the planning period of 2011-2031 involving these key planning functions:

- Develop planning objectives and assumptions.
- Consider the impacts of anticipated or pending regulations or events on existing resources (environmental, renewables, etc.).
- Consider two different regulatory constructs to assess the impact of potential CO_2 or Energy Policy legislation. The first included a CO_2 cap and trade construct with allowance prices beginning in 2016 projected at the lower end of pricing of previous proposed legislation. The second construct was based on Clean Energy Standard where an increasing percentage of retail sales starting in 2015 would come from energy efficiency, renewables, coal generation with carbon sequestration, nuclear and some allowance for combined cycle generation. Detailed descriptions of each of these constructs are available in Chapter 8.
- Prepare the electric load forecast. More details of this step may be found in Chapter 3.
- Identify EE and DSM options. More details concerning this step can be found in Chapter 4.
- Identify and economically screen for the cost-effectiveness of supply-side resource options. More details concerning this step of the process can be found in Chapter 5.
- Integrate the energy efficiency, renewable, and supply-side options with the existing system and electric load forecast to develop potential resource portfolios to meet the desired reserve margin criteria. More details concerning this step of the process can be found in Chapter 8 and Appendix A.
- Perform detailed modeling of potential resource portfolios to determine the resource portfolio that exhibits the lowest cost (lowest net present value of costs) to customers over a wide range of alternative futures. More details concerning this step of the process can be found in Chapter 8 and Appendix A.
- Evaluate the ability of the selected resource portfolio to minimize price and reliability risks to customers. More details concerning this step of the process can be found in Chapter 8 and Appendix A.

The analytical methodology includes the incorporation of sensitivity analysis of variables representing the highest risk going forward, such as the load forecast, construction costs, fuel prices, EE, carbon prices and emerging policy.

3. ELECTRIC LOAD FORECAST

The following section provides details on the Spring 2011 Load Forecast.

Duke Energy Carolinas retail sales have grown at an average annual rate of 0.9 percent from 1995 to 2010. The following table shows historical and projected major customer class growth, at a compound annual rate.

Table 3.A
Retail Load Growth (kWh sales)

Time Period	Total Retail	Residential	Commercial	Industrial Textile	Industrial Non-Textile
1995-2010	0.9%	2.7%	2.8%	-7.1%	-0.4%
1995-2005	1.2%	2.6%	3.4%	-6.0%	0.7%
2005-2010	0.4%	2.9%	1.7%	-9.4%	-2.6%
2010-2030	1.5%	1.5%	2.0%	-0.9%	1.1%

*Growth rates from 2010-2030 are derived using weather adjusted values for 2010. This differs from the Forecast Book located in Appendix B, which uses actual 2010 values.

A significant decline in the Industrial Textile class was the key contributor to the low load growth from 2005 to 2010, however, this decline was mostly offset by contributions in the Residential and Commercial classes over the same period. Over the last 5 years, an average of approximately 27,000 new residential customers per year has been added to the Duke Energy Carolinas service area.

Duke Energy Carolinas' total retail load growth over the planning horizon is driven by projected steady increases in the Residential, Commercial and Other Industrial classes. Textiles, however, are projected to experience a slow decline over the forecast horizon.

Retail load growth summaries are shown in the Duke Energy Carolinas Spring 2011 Forecast book in Appendix B.

The Residential load growth summaries shown in Table 3.A use the same history and forecast data for Residential Sales located on page 10 of the Forecast book in Appendix B. The Commercial load growth summaries use the same history and forecast data for Commercial Sales located on page 11 of the Forecast book in Appendix B. The Industrial

Textile load growth summaries use the same history and forecast data for Textile Sales located on page 13 of the Forecast book in Appendix B. The Industrial Non-Textile load growth summaries use the same history and forecast data for Other Industrial Sales located on page 14 of the Forecast book in Appendix B.

Table 3.B

Retail Customers (1000s, Annual Average)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Residential	1,814	1,840	1,872	1,901	1,935	1,972	2,016	2,052	2,059	2,072
Commercial	295	300	307	313	319	325	331	334	333	334
Industrial	8	8	8	8	7	7	7	7	7	7
Other	11	11	11	12	13	13	13	14	14	14
Total	2,128	2,159	2,198	2,234	2,275	2,317	2,368	2,407	2,413	2,427

Table 3.C

Electricity Sales (GWh Sold - Years Ended December 31)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Residential	23,272	24,466	23,947	25,150	26,108	25,816	27,459	27,335	27,273	30,049
Commercial	23,666	24,242	24,355	25,204	25,679	26,030	27,433	27,288	26,977	27,968
Industrial	26,902	26,259	24,764	25,209	25,495	24,535	23,948	22,634	19,204	20,618
Other	281	271	270	269	269	271	278	284	287	287
Total Retail	74,121	75,238	73,336	75,833	77,550	76,653	79,118	77,541	73,741	78,922
Wholesale	1,484	1,530	1,448	1,542	1,580	1,694	2,454	3,525	3,788	5,166
Total GWH	75,605	76,769	74,784	77,374	79,130	78,347	81,572	81,066	77,528	84,088
		.								

Note: Wholesale sales will vary over time due to new contract agreements.

Wholesale Power Sales Commitments

Table 3.D on the following page contains information concerning Duke Energy Carolinas' wholesale contracts.

Table 3.D — **WHOLESALE CONTRACTS**

Wholesale Customer	Contract Designation	Contract Term	Commitment (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NC/SC Munis		December 31,2018	331	334	340	346	352	358	364	370	376	383
Concord, NC	Partial	with annual										
Dallas, NC	Partial	renewals. Can be										
Forest City, NC	Partial	terminated on one-										
Kings Mountain, NC	Partial	year notice by										
Lockhart Power	Partial	either party after										
Due West, SC	Partial	current contract										
Prosperity, SC	Partial	term.										
Greenwood, SC	Full											
Highlands, NC	Full											
Western Carolina University	Full											
See Note 1												
New River EMC		December 31. 2021	35	35	36	37	37	38	39	40	41	42
See Note 1	Full											
Blue Ridge EMC	Full	December 31, 2021	183	187	191	196	200	205	210	215	219	224
See Note 1												
Piedmont EMC	Full	December 31, 2021	90	91	92	93	94	95	97	98	99	100
See Note 1												
Rutherford EMC	Partial	December 31, 2021	159	164	193	197	211	215	219	223	227	231
See Note 1												
Haywood EMC	Full	December 31, 2021	26	26	26	27	27	28	28	29	29	29
See Note 1												
Central	Partial incr.to Full	January 1, 2013 - December 31, 2030	0	0	121	247	377	511	650	794	898	913
See Note 1												
NCEMC	Contract Backstand	Through Operating Life of Catawba and McGuire Nuclear Station	586	586	586	586	586	586	586	586	586	586
See Note 2												
NCEMC	Capacity Sale	January 1, 2009 - December 31, 2038	72	72	72	72	72	72	72	72	72	72

Note 1: The analyses in the 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

The Spring 2011 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 requirements from other suppliers. While this may reduce Duke Energy Carolinas obligation to serve those customers, Duke Energy Carolinas assumes for planning purposes that the contracts displayed in Table 3.D will be extended through the duration of the forecast horizon.

Pursuant to 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 2011 Forecast book located in Appendix B. Also, per NCUC Rule R8-60(i)(1)(A), 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 17-22 of the 2011 Forecast book located in Appendix B.

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, both with and without the impact of utility-sponsored energy efficiency programs are shown below in Tables 3.E and 3.F.

Load duration curves, with and without utility-sponsored energy efficiency programs, follow Tables 3.E and 3.F, and are shown as Charts 3.A and 3.B.

These values reflect the loads that Duke Energy Carolinas is contractually obligated to provide and cover the period from 2011 to 2031.

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 compound annual growth rate of 1.8 percent in the summer peak demand, while winter peaks are forecasted to grow at 1.7 percent. The forecasted compound annual growth rate for energy is 1.9 percent.

If the impacts of new energy efficiency programs are included, the projected compound annual growth rate for the summer peak demand is 1.7 percent, while winter peaks are forecasted to grow at a rate of 1.6 percent. The forecasted compound annual growth rate for energy is 1.7 percent.

Table 3.E
Load Forecast without Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2011	17,596	17,121	91,750
2012	17,907	17,425	93,281
2013	18,353	17,869	95,307
2014	18,800	18,303	97,455
2015	19,273	18,746	100,044
2016	19,752	19,180	102,481
2017	20,220	19,665	104,929
2018	20,680	20,123	107,476
2019	21,122	20,539	109,865
2020	21,475	20,868	111,873
2021	21,826	21,128	113,859
2022	22,152	21,482	115,560
2023	22,469	21,782	117,366
2024	22,777	22,080	119,235
2025	23,120	22,379	121,087
2026	23,430	22,649	123,013
2027	23,777	22,922	124,979
2028	24,109	23,280	127,025
2029	24,419	23,584	129,081
2030	24,765	23,885	131,175
2031	25,121	24,186	133,281

Chart 3.A- Load Duration Curves without Energy Efficiency

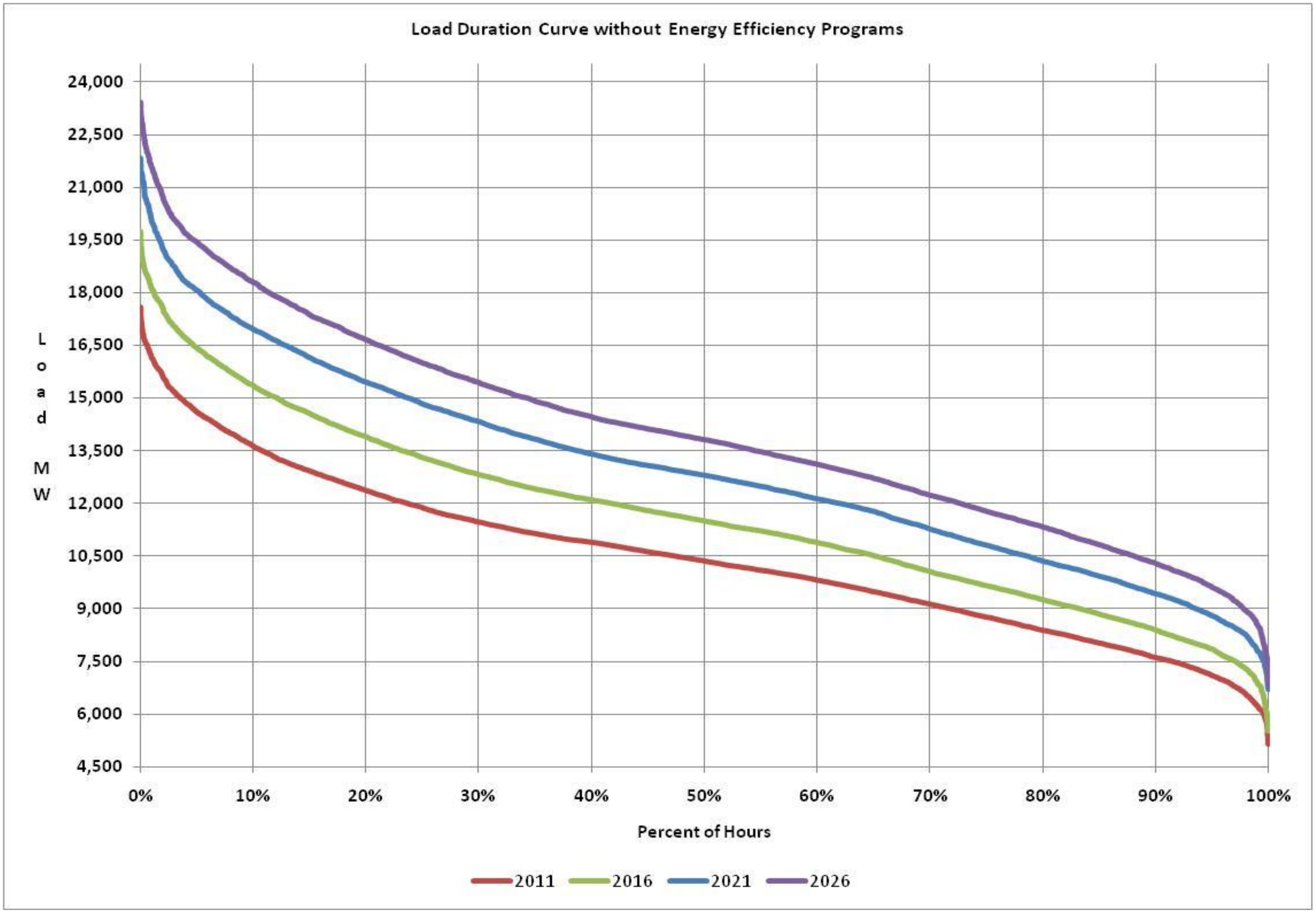
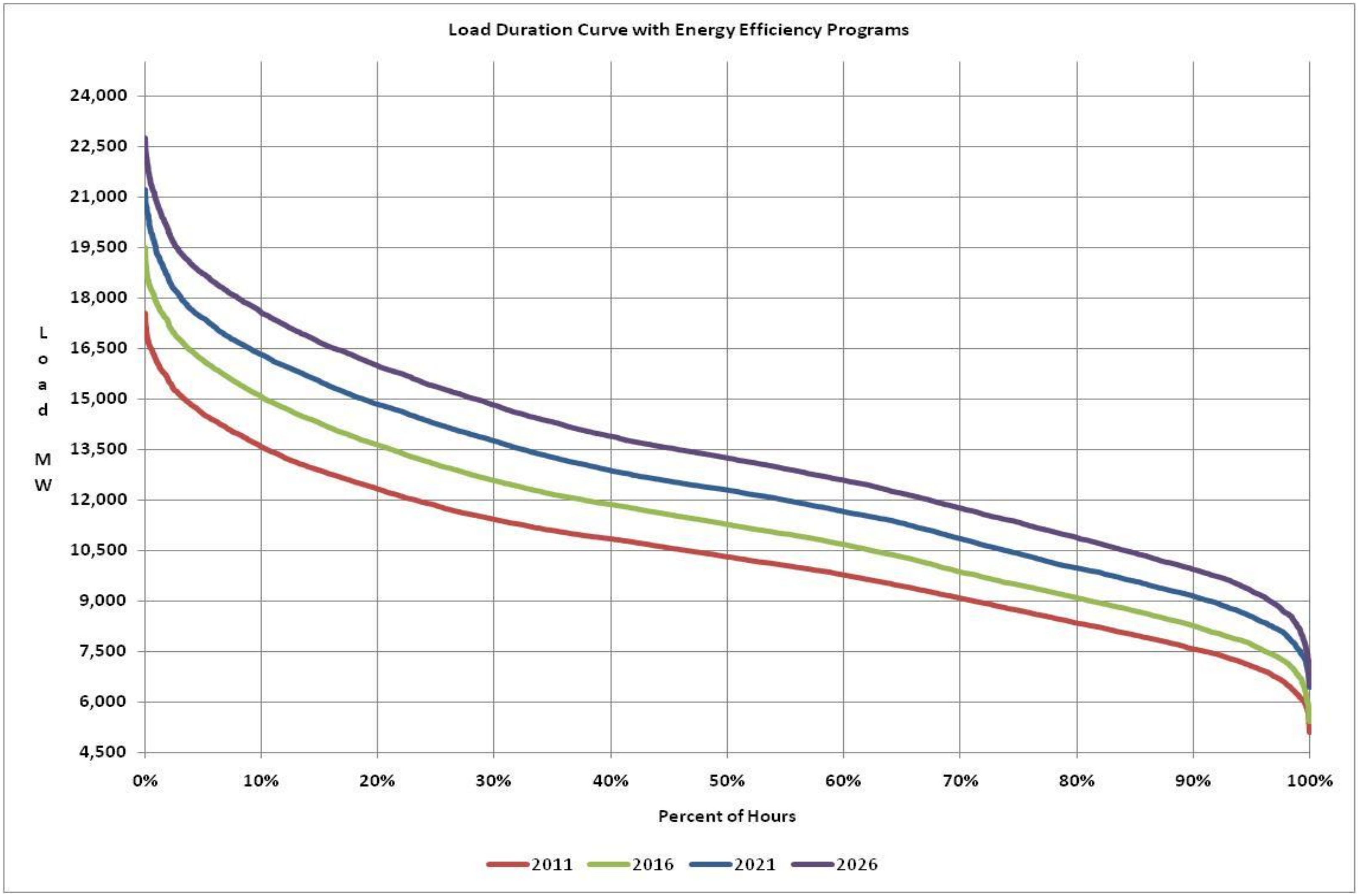


Table 3.F
Load Forecast with Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2011	17,557	17,115	91,479
2012	17,812	17,359	92,679
2013	18,245	17,773	94,518
2014	18,680	18,177	96,507
2015	19,032	18,543	98,517
2016	19,476	18,891	100,472
2017	19,877	19,305	102,438
2018	20,265	19,694	104,503
2019	20,644	20,042	106,409
2020	20,901	20,304	107,936
2021	21,214	20,492	109,440
2022	21,530	20,835	111,063
2023	21,836	21,124	112,791
2024	22,135	21,412	114,580
2025	22,465	21,697	116,350
2026	22,733	21,956	118,193
2027	23,099	22,217	120,075
2028	23,420	22,565	122,035
2029	23,715	22,853	124,003
2030	24,050	23,142	126,008
2031	24,393	23,430	128,025

Chart 3.B - Load Duration Curves with Energy Efficiency



4. ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT

Current Energy Efficiency and Demand-Side Management Programs

In May 2007, Duke Energy Carolinas filed its application for approval of EE and DSM programs under its save-a-watt initiative. The Company received the final order for approval for these programs from the NCUC in July 2010 and from the PSC in May 2009.

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 level and frequency of customer participation. In general, programs are offered in 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). The following are the current EE and DSM programs in place in the Carolinas:

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 programs are:

- **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.

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' actions after notification of an event or after receiving pricing signals. Duke Energy Carolinas' current interruptible and time-of-use curtailment programs include:

- **Interruptible Power Service (IS)** (North Carolina Only) **-** 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 (SG)** (North Carolina Only) **-** 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.

- **PowerShare®** is a non-residential curtailment program consisting of four options: an emergency only option for curtailable load (PowerShare® Mandatory), an emergency only option for load curtailment using on-site generators (PowerShare® Generator), an economic based voluntary option (PowerShare® Voluntary), and a combined emergency and economic option that allows for increased notification time of events (PowerShare® CallOption).
    - PowerShare® Mandatory: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail during utility-initiated emergency events. Participants also receive energy credits for the load curtailed during events. Customers enrolled may also be enrolled in PowerShare® Voluntary and eligible to earn additional credits.
    - PowerShare® Generator: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail during utility-initiated emergency events and their performance during monthly test hours. Participants also receive energy credits for the load curtailed during events.
    - PowerShare® Voluntary: Enrolled 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 participate in the event and will be paid the posted energy credit for load curtailed.
    - PowerShare® CallOption: This DSM program offers a participating customer the ability to receive credits when the customer agrees, at the Company's request, to reduce and maintain its load by a minimum of 100 kW during Emergency and/or Economic Events. Credits are paid for the load available for curtailment, and charges are applicable when the customer fails to reduce load in accordance with the participation option it has selected. Participants are obligated to curtail load during emergency events. CallOption offers four participation options to customers: PS 0/5, PS 5/5, PS 10/5 and PS 15/5. All options include a limit of five Emergency Events and set a limit for Economic

Events to 0, 5, 10 and 15 respectively.

- **Rates using price signals**

  - **Residential Time-of-Use (including a Residential Water Heating rate)**
    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 Optional Time-of-Use rates**
    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.

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 Assessments**

  The Residential Energy Assessments program includes two separate measures: 1) Personalized Energy Report (PER) and 2) Home Energy House Call.

  The PER program is a residential energy efficiency program that provides single family home customers with a customized report about their home and family and how they use energy. In addition, the customer receives CFLs as an incentive to participate in the program.

The PER program requires customers to provide information about their home, number of occupants, equipment and energy usage and has two variations:

- A mailed offer where customers are asked to complete an included energy survey and mail it back to Duke Energy or complete the same survey online. Customers mailing the energy survey receive their PER in the mail and those completing it online receive their PER online as a printable PDF document.

- An online offer to our customers that have signed into our Online Services (OLS) bill pay and view environment. Online participants complete their energy survey online get their PER online as a printable PDF.

Home Energy House Call (HEHC) is a free in-home assessment designed to help our customers learn about home energy usage and how to save on monthly bills. The program provides personalized information unique to the customer's home and energy practices. An energy specialist visits the customer's home to analyze the total home energy usage and to pinpoint energy saving opportunities. An energy specialist will also explain how to improve the heating and cooling comfort levels, check for air leaks, examine insulation levels, review appliances, help the customer preserve the environment for the future and keep electric costs low. A customized report is prepared, explaining the steps the customer can take to increase efficiency. As a part of the Home Energy House Call program, customers receive an Energy Efficiency Starter Kit. At the request of the customer, the energy specialist can install the efficiency items to allow the customer to begin saving immediately.

- **Low Income Energy Efficiency and Weatherization Program**
  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.

- **Residential Smart $aver® Energy Efficient Products Program**
  The Smart $aver® Program provides incentives to residential customers who

purchase energy-efficient equipment. The program has two components – CFLs and high-efficiency air conditioning equipment.

CFLs

The CFL program is designed to offer incentives to customers and increase energy efficiency by installing CFLs in high use fixtures in the home. The incentives have been offered in a variety of ways. The first deployment of this program distributed free coupons to be redeemed by the customer at a variety of retail stores. Later deployments used business reply cards and a web-based on-demand ordering tool where CFLs are shipped directly to the customer's home.

Heating Ventilation & Air Conditioning (HVAC) and Heat Pump

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. The program is designed to increase the efficiency of air conditioning systems in new homes and for replacements in existing homes.

- **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 as part of the Prescriptive program: high-efficiency lighting, high-efficiency air conditioning equipment, high-efficiency motors, high-efficiency pumps, variable frequency drives, food services and process equipment. Customer incentives may be paid for other high-efficiency equipment as determined by the Company to be evaluated on a case-by-case basis through the Custom program.

The projected impacts from these programs are included in this year's assessment of generation needs.

Additional Programs Being Considered

In addition to our current portfolio of programs, Duke Energy Carolinas plans to add three additional concepts to our portfolio. These programs are similar to approved programs offered by Progress Energy Carolinas. The three additional programs are Additional Smart $aver® Measures, Direct Install Low Income and Appliance Recycle. A high-level overview is provided below.

- **Additional Smart $aver® Measures**

  Partnering with HVAC dealers, the program pays incentives to partially offset the cost of air conditioner and heat pump tune ups and duct sealing. This would be a new program and has not been offered in any of Duke Energy's jurisdictions. Projected impacts of this program were included in the analysis of generation needs.

- **Direct Install Low Income Program**
  Program that targets low income neighborhoods providing high impact direct install measures (CFLs, pipe and water heater wrap, low flow aerators and showerheads, HVAC filters and air infiltration sealing) and energy efficiency education. Projected impacts of this program were included in the analysis of generation needs.

- **Appliance Recycling Program**
  This is a program to incentivize households to turn in old inefficient refrigerators and freezers. Projected impacts of this program were not included in the analysis of generation needs due to the timing of approval of this concept.

The following pilot programs have been approved:

- **Residential Retrofit**
  This program was approved in North Carolina in Docket E-7, Sub 952 on January 25, 2011 and in South Carolina in Docket 2010-51-E on February 24, 2010. The Residential Retrofit program is designed to assist residential customers in assessing their energy usage, to provide recommendations for more efficient use of energy in their homes and to encourage the installation of energy efficient improvements by offsetting a portion of the cost of implementing the recommendations from the assessment. Projected impacts of this pilot program were included in the analysis of generation needs.

- **Home Energy Comparison Report**
  This pilot was approved by the Public Service Commission of South Carolina in Docket 2010-50-E on March 24, 2010 and will test the energy savings impact of providing periodic reports to targeted customers showing how their energy consumption compares to that of similar neighbors. This pilot program is currently only offered in South Carolina. Projected impacts of this pilot program were included in the analysis of generation needs.

- **Smart Energy Now (SEN)**
  The SEN pilot program was approved by the NCUC in Docket E-7, Sub 961 on February 14, 2011 and is designed to reduce energy consumption within the

commercial office space located in Charlotte City Center through community engagement leading to behavioral modification. In order to enable building managers and occupants to effectively make these behavioral modifications, they will be provided with additional energy consumption information and actionable efficiency recommendations. Projected impacts of this pilot were not included in the analysis of generation needs due to the timing of approval.

The following pilot program is being proposed:

- **Home Energy Manager (HEM) Lite**
  HEM Lite is a residential energy management solution designed for home owners with broadband internet service. The product offers energy efficiency and demand response benefits through a Wi-Fi enabled thermostat that will manage a customer's air conditioning system by providing schedules, modes (such as home/away/vacation), energy savings tips, messages, and alerts. The customer will have the tools to access and control their thermostat through any web browser or by downloading an "app" on their smart phone. In addition, it will provide customers with the opportunity to participate in demand response events. Overall, this product will provide simple, intuitive, and effective tools that will enable the customer to reduce and manage their overall energy usage.

Future EE and DSM programs

In addition to the programs and pilots listed above, Duke Energy Carolinas is actively working to add new programs to our portfolio that have not yet been developed. Estimates of the impacts of these yet-to-be-developed programs have been included in this analysis of generation needs.

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 DSM and EE measures at an hourly level across distributions of weather conditions 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 and 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, and Participant Test. DSMore provides the results of those tests for any type of EE or DSM program.

- The UCT compares utility benefits (avoided costs) to incurred utility costs to implement the program, and does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs, and load (line) losses.

- The RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program.

- The TRC Test compares the total benefits to the utility and to participants relative to the costs to the utility to implement the program along with the costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test, however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC.

- The Participant Test evaluates programs from the perspective of the program's participants. The benefits include reductions in utility bills, incentives paid by the utility and any state, federal or local tax benefits received.

The use of multiple tests can ensure the development of a reasonable set of DSM and EE programs and indicate the likelihood that customers will participate.

Energy Efficiency and Demand-Side Management Programs

Duke Energy Carolinas has made a strong commitment to EE and DSM. The Company recognizes EE and DSM as a reliable, valuable resource that is an option in the portfolio available to meet customers' growing need for electricity along with coal, nuclear, natural gas, and renewable energy. These EE and DSM programs help customers meet their energy needs with less electricity, less cost and less environmental impact. The Company will manage EE and DSM to 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 EE programs for the benefit of its customers.

The Duke Energy Carolinas' approved EE plan is consistent with the requirement set forth in the Cliffside Unit 6 CPCN Order to invest 1% of annual retail electricity revenues in energy efficiency and demand side programs, subject to the results of ongoing collaborative workshops and appropriate regulatory treatment. For the period between the deployment of the Company's save-a-watt portfolio in 2009 and 12/31/2010, Duke Energy's conservation and demand response programs have reduced overall demand, including line losses, by approximately 500,000 net MWh and the Summer Peak has been reduced by over 700 MW. However, pursuing EE and DSM initiatives will not meet all our growing demands for electricity. The Company still envisions the need to secure additional nuclear and gas generation as well as cost-effective renewable generation, but the EE and DSM programs offered by Duke Energy Carolinas could address approximately half of the 2015 new resource need, if such programs perform as expected.

Table 4.A provides the base case projected load impacts of the EE and DSM programs through 2031. These load impacts were included in the base case IRP analysis. The Company assumes total EE savings will continue to grow on an annual basis through 2035, however the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan. The projected load impacts from the DSM programs are based upon the Company's continuing, as well as the new, demand response programs. These projections have decreased from last year in part due to incorporation of impacts from the EPA's RICE rule. This EPA rule restricts the use of customer-sited generators to a very low level for demand response purposes. EPA is currently collecting comments on this rule so it is uncertain at this time if the rule will change and what the eventual impact will be on the Company's demand response programs. Duke Energy Carolinas is considering alternatives to address the reduction in DSM capability available.

Table 4.B provides a high case load impact scenario from the Company's EE and DSM programs. For EE programs, this scenario uses the full target impacts of the Company's 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 2030, beyond which point the increase in the load impacts are adjusted to match the projected growth in retail sales. For DSM programs, the load impacts are increased to match the increase between base case and high case MWH retail sales for the appropriate customer class.

Table 4.C incorporates December 31, 2010 participation levels for all demand response programs and the capability of these programs projected for the summer of 2011.

Table 4.A Load Impacts of EE and DSM Programs – Base Case

Conservation and Demand Side Management Programs								
	Conservation		Demand Response Peak MW					Total
			Summer Peak MW					Summer Peak
Year	MWh	MW	IS	SG	PowerShare	PowerManager	Total	MW Impacts
2011	271,026	39	145	48	331	249	775	814
2012	601,792	80	135	46	367	294	842	922
2013	788,832	102	128	19	364	343	854	955
2014	947,489	120	122	18	391	393	923	1,044
2015	1,526,825	208	116	17	414	436	983	1,190
2016	2,008,940	276	110	16	429	432	987	1,262
2017	2,491,055	343	110	16	429	432	986	1,329
2018	2,973,170	410	110	16	429	432	986	1,396
2019	3,455,286	478	110	16	429	432	986	1,465
2020	3,937,401	544	110	16	429	432	986	1,530
2021	4,419,513	611	110	16	429	432	986	1,598
2022	4,496,857	622	110	16	429	432	986	1,608
2023	4,575,552	633	110	16	429	432	986	1,619
2024	4,655,623	642	110	16	429	432	986	1,629
2025	4,737,095	655	110	16	429	432	986	1,642
2026	4,819,996	667	110	16	429	432	986	1,653
2027	4,904,346	679	110	16	429	432	986	1,665
2028	4,990,171	688	110	16	429	432	986	1,675
2029	5,077,501	703	110	16	429	432	986	1,689
2030	5,166,356	715	110	16	429	432	986	1,701
2031	5,256,768	727	110	16	429	432	986	1,714

Table 4.B Load Impacts of EE and DSM Programs – High Case

Conservation and Demand Side Management Programs								
	Conservation		Demand Response Peak MW					Total
			Summer Peak MW					Summer Peak
Year	MWh	MW	IS	SG	PowerShare	PowerManager	Total	MW Impacts
2011	271,026	39	163	54	373	264	855	894
2012	601,792	80	154	53	419	311	936	1,016
2013	788,832	102	147	21	418	362	947	1,049
2014	947,489	120	140	20	450	415	1,024	1,145
2015	2,070,090	283	134	19	478	460	1,091	1,374
2016	2,809,117	387	128	18	497	456	1,100	1,487
2017	3,548,145	490	128	18	500	457	1,104	1,594
2018	4,287,171	593	129	18	502	458	1,107	1,701
2019	5,026,201	698	129	19	503	460	1,111	1,809
2020	5,765,231	798	130	19	505	462	1,115	1,913
2021	6,504,259	902	130	19	507	463	1,118	2,020
2022	7,243,284	1,004	130	19	508	465	1,122	2,126
2023	7,982,312	1,107	131	19	510	467	1,126	2,233
2024	8,721,341	1,207	131	19	511	470	1,131	2,338
2025	9,460,367	1,313	132	19	513	472	1,136	2,448
2026	10,199,395	1,416	132	19	515	475	1,140	2,556
2027	10,938,425	1,519	132	19	516	477	1,145	2,663
2028	11,677,451	1,617	133	19	518	480	1,150	2,766
2029	12,416,478	1,724	133	19	520	483	1,155	2,879
2030	13,155,507	1,827	134	19	521	486	1,160	2,987
2031	13,385,729	1,859	134	19	523	489	1,165	3,024

Table 4.C

DSM Program Participation and Capability		
DSM Program Name	Participation as of 12/31/10	2011 Estimated Summer IRP Capability (MW)
IS	69	145
SG	98	48
PowerShare Mandatory	115	313
PowerShare Generator	4	18
PowerShare Voluntary	4	N/A
PowerShare CallOption		
Level 0/5	-	-
Level 5/5	-	-
Level 10/5	-	-
Level 15/5	1	0
Power Manager	198,503	249
Total	198,794	775

Programs Evaluated but Rejected

Duke Energy Carolinas has not rejected any programs as a result of its EE and DSM program screening.

Looking to the Future

DSM Implementation Effectiveness – Duke Energy Carolinas has begun a review of the effectiveness of its DSM programs to reduce peak demand during reliability events. The goal of this review will be to gain insight on DSM parameters, such as duration of events and number of events and how these parameters impact the load reduction captured during a reliability event.

Grid Modernization – Duke Energy is pursuing implementation of grid modernization throughout the enterprise. The recent $200 million grant awarded to Duke Energy from the US DOE helps further that goal. Grid modernization is a mechanism to further enable adoption and market penetration of EE, DSM and plug-in electric vehicles (PEVs). In order to meet and support EE and DSM goals, the NCUC proposed a requirement to include grid modernization impacts in the IRP for North Carolina electric utilities (including Duke Energy Carolinas) in Docket E-100, Sub 126. Duke Energy Carolinas filed joint comments along with Dominion-North Carolina Power on February 26, 2010, in which the two utilities supported the inclusion of the impact of grid modernization as part of the IRP. The two utilities also advocated that grid modernization should be treated similarly to how EE and DSM resources are incorporated into the IRP. Progress Energy later joined Duke Energy Carolinas and Dominion-North Carolina Power in reply comments filed before the NCUC on March 26, 2010, further emphasizing these points.

5. SUPPLY-SIDE RESOURCES

A. EXISTING GENERATION PLANTS IN SERVICE

Duke Energy Carolinas' generation portfolio includes 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 its 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 2010, Duke Energy Carolinas' nuclear and coal-fired generating units met the vast majority of customer needs by providing 51.2% and 46.7%, respectively, of Duke Energy Carolinas' energy from generation. Hydroelectric generation, CT generation, solar generation, long term PPAs, and economical purchases from the wholesale market supplied the remainder.

Existing Resources

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

Table 5.A

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

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Allen	1	162.0	167.0	Belmont, N.C.	Conventional Coal
Allen	2	162.0	167.0	Belmont, N.C.	Conventional Coal
Allen	3	261.0	270.0	Belmont, N.C.	Conventional Coal
Allen	4	276.0	282.0	Belmont, N.C.	Conventional Coal
Allen	5	266.0	275.0	Belmont, N.C.	Conventional Coal
Allen Steam Station		**1127.0**	**1161.0**		
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	5	128.0	131.0	Salisbury, N.C.	Conventional Coal
Buck	6	128.0	131.0	Salisbury, N.C.	Conventional Coal
Buck Steam Station		**256.0**	**262.0**		
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	556.0	562.0	Cliffside, N.C.	Conventional Coal
Cliffside Steam Station		**754.0**	**764.0**		
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		**7165.0 MW**	**7282.0 MW**		
Buck	7C	25.0	30.0	Salisbury, N.C.	Natural Gas/Oil-Fired

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
					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

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Lincoln Station CTs		**1267.2**	**1488.0**		
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	0	0	Morganton, N.C.	Hydro
Bridgewater Hydro Station		**11.5**	**11.5**		
Bryson City	1	0.48	0.48	Whittier, N.C.	Hydro
Bryson City	2	0	0	Whittier, N.C.	Hydro
Bryson City Hydro Station		**0.48**	**0.48**		
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**		
Lookout Shoals	1	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals	2	9.3	9.3	Statesville, N.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
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	0	Franklin, N.C.	Hydro
Franklin	2	.6	.6	Franklin, N.C.	Hydro
Franklin Hydro Station		**.6**	**.6**		
Mission	1	0	0	Murphy, N.C.	Hydro
Mission	2	0	0	Murphy, N.C.	Hydro
Mission	3	0.6	0.6	Murphy, N.C.	Hydro
Mission Hydro Station		**0.6**	**0.6**		
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
Tuckasegee Hydro Station		**2.5**	**2.5**		
Queens Creek	1	1.44	1.44	Topton, N.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Queens Creek Hydro Station		**1.44**	**1.44**		
TOTAL N.C. HYDRO		**603.97 MW**	**603.97 MW**		
TOTAL N.C. SOLAR		**8.43 MW**	**8.43 MW**	N.C.	Solar
TOTAL N.C. CAPABILITY		**12,243.60 MW**	**12,746.40 MW**		

Table 5.B
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	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	7C	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	8C	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	9C	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	10C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	11C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	12C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	13C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	14C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	15C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost Station CTs		**176.0**	**176.0**		
Lee	7C	41.0	41.0	Pelzer, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Lee	8C	41.0	41.0	Pelzer, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Lee Station CTs		**82.0**	**82.0**		
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

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
					Combustion Turbine
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		**853.4 MW**	**997.2 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	195.0	195.0	Salem, S.C.	Pumped Storage
Jocassee	2	195.0	195.0	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		**780.0**	**780.0**		
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		**2140.0 MW**	**2140.0 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

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
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
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	0	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	0	0	Blacksburg, S.C.	Hydro
Gaston Shoals Hydro Station		**2.0**	**2.0**		
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	0	0	Great Falls, S.C.	Hydro
Great Falls	4	0	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	0	0	Great Falls, S.C.	Hydro
Great Falls	8	0	0	Great Falls, S.C.	Hydro
Great Falls Hydro Station		**12.0**	**12.0**		
Rocky Creek	1	0	0	Great Falls, S.C.	Hydro
Rocky Creek	2	0	0	Great Falls, S.C.	Hydro
Rocky Creek	3	0	0	Great Falls, S.C.	Hydro
Rocky Creek	4	0	0	Great Falls, S.C.	Hydro
Rocky Creek	5	0	0	Great Falls, S.C.	Hydro
Rocky Creek	6	0	0	Great Falls, S.C.	Hydro
Rocky Creek	7	0	0	Great Falls, S.C.	Hydro
Rocky Creek	8	0	0	Great Falls, S.C.	Hydro
Rocky Creek Hydro Station		**0**	**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**		

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
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	0	0	Blacksburg, S.C.	Hydro
99 Islands	6	0	0	Blacksburg, S.C.	Hydro
99 Islands Hydro Station		**6.4**	**6.4**		
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		**465.4 MW**	**465.4 MW**		
TOTAL S.C. CAPABILITY		**8,624.8 MW**	**8,895.6 MW**		

Table 5.C
Total Generation Capability [a,b,c,d,e]

NAME	SUMMER CAPACITY MW	WINTER CAPACITY MW
TOTAL DUKE ENERGY CAROLINAS GENERATING CAPABILITY	**20,868.4**	**21,642.0**

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 June 22, 2011.

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%

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 need to meet its load obligation. Below are the known and/or anticipated changes and their respective 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. As of June 2011, the project is over 80% complete.

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

Jocassee Unit 1 and 2 Runner Upgrades
This project is completed. Capacity additions reflect a 50 MW capacity uprate at the Jocassee pumped storage facility from increased efficiency of the new runners. These uprates were included in the 2011 IRP analysis.

Buck Combined Cycle Natural Gas Unit
The Company received the CPCN for this project in June 2008 and received the corresponding air permit in October 2008. The 620 MW Buck CC unit is scheduled to be operational by the end of 2011. Construction and commissioning activities are underway and the project is currently over 90% complete.

Dan River Combined Cycle Natural Gas Unit
The Company received the CPCN for this project concurrently with the CPCN for the Buck CC project in June 2008 and received its air permit for this project in August 2009. The 620 MW Dan River CC unit is scheduled to be operational by the end of 2012. Construction is underway and the project is currently over 50% complete.

Lee Steam Station Natural Gas Conversion
Lee Steam Station was originally designed to generate with natural gas or coal as a fuel source. Switching fuel sources from coal to natural gas could prove to be an economic solution to avoid adding costly pollution control equipment or replacing the 370 MW of capacity at an alternative site. For planning purposes Lee Steam Station will be retired as

a coal station the fourth quarter of 2014 and converted to natural gas by January 1, 2015. Preliminary engineering has been completed and more detailed project development and regulatory efforts will begin in 2011.

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 5.D 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[2]. 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 NCUC 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 Energy Carolinas may seek modification of this plan.

Additionally, multiple environmental regulatory issues are presently converging as the EPA has proposed new rules to regulate multiple areas relating to generation resources. These new rules, if implemented, will increase the need for the installation of additional control technology or retirement of coal fired generation in the 2014 to 2018 timeframe. Anticipating that there will be increased control requirements, the Carolinas 2011 IRP incorporates a planning assumption that all coal-fired generation that does not have an installed SO_2 scrubber will be retired by 2015.

Table 5.D 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

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

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.

Table 5.D
Projected Unit Retirements

STATION	CAPACITY IN MW	LOCATION	EXPECTED RETIREMENT	PLANT TYPE
Buck 4*	38	Salisbury, N.C.	RETIRED	Conventional Coal
Buck 3*	75	Salisbury, N.C.	RETIRED	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.	4/01/2012	Conventional Coal
Dan River 2*	67	Eden, N.C.	3/01/2012	Conventional Coal
Dan River 3*	142	Eden, N.C.	4/01/2012	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.	1/01/2015	Conventional Coal
Riverbend 5*	94	Mt. Holly, N.C.	1/01/2015	Conventional Coal
Riverbend 6***	133	Mt. Holly, N.C.	1/01/2015	Conventional Coal
Riverbend 7***	133	Mt. Holly, N.C.	1/01/2015	Conventional Coal
Buck 5***	128	Spencer, N.C.	1/01/2015	Conventional Coal
Buck 6***	128	Spencer, N.C.	1/01/2015	Conventional Coal
Lee 1***	100	Pelzer, S.C.	10/01/2014	Conventional Coal
Lee 2***	100	Pelzer, S.C.	10/01/2014	Conventional Coal
Lee 3***	170	Pelzer, S.C.	10/01/2014	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 in 2009 based on derates, availability of replacement parts and the general condition of the remaining units.

*** For the 2011 IRP process, remaining coal units without scrubbers were assumed to be retired by 2015. 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 final regulations or new legislation allows for latitude in the retirement date if a retirement commitment is made versus adding controls, the retirement date may be adjusted.

Fuel Supply

Duke Energy Carolinas' current 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.

Coal

Until the economic downturn in 2008, Duke Energy Carolinas had burned approximately 19 million tons of coal annually. However, the burn dropped drastically in 2009 before recovering somewhat in 2010 to around 15 million tons of coal, a level that is projected to be maintained over the next few years.

The Company primarily procures coal from Central Appalachian (CAPP) 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 and internationally.

Although CAPP coal market prices are well below the all-time highs experienced in 2008, low gas prices have displaced some of the demand for CAPP from marginal units. Projected market prices for CAPP two years out are 20-50% higher than those seen in 2010, reflecting higher production costs combined with a more balanced supply and demand picture. Increasingly strict federal safety regulations and surface mine permit requirements in Central Appalachia could result in lower production and corresponding higher prices (relative to other coal produced in other basins.) For this reason, the Company is exploring means to develop greater supply and transportation flexibility in order to minimize the Company's dependency on CAPP.

Natural Gas

Duke Energy is still feeling the effects of the supply and demand imbalance which began during the fall of 2008 as the economy stumbled and new supplies of gas from unconventional sources came on line. Gas prices tumbled in 2009 to the $4/mmbtu range and the NYMEX forward market has continued to trade within a very narrow band over the past year as new supplies from shale resources continue to outpace the demand growth from the recovering industrial sector. This imbalance should start to wane in 2012, however, as several new factors begin to weigh on the market.

The first factor is the shift in drilling capital away from dry natural gas toward oil shales or gas shales that are rich in natural gas liquids (NGLs). NGLs include ethane, butane, propane and natural gasoline, and have various uses. A shift is already being seen in the Haynesville and Barnett regions, which were the early "game changers" in this area. With oil futures holding steady near $100/barrel and gas futures down in the $4 - $6/MMBTU range, the Company has perceived a strategic shift to oil/liquids directed drilling.

The second factor which will add near-term pressure to the market is the recently promulgated CSAPR for SO_2 and NO_x, scheduled to go into effect on Jan 1, 2012. Duke Energy Carolinas anticipates that CSAPR will push uncontrolled or un-scrubbed coal units higher in the dispatch order and further extend the gas displacement of coal; this is already occurring in areas where CAPP coal is the primary coal fuel source.

The third factor is the recovery in the petro-chemical demand for gas. A weak U.S. dollar coupled with a huge advantage in feedstock price, domestic gas versus global oil priced gas contracts, will lead to sustained growth in industrial gas demand. The size of the U.S. natural gas resource base has grown immensely over the past few years, but not all of these resources will remain economic at the current market price. Improvements are expected in the drilling and completion process of shale resources, and new regulations are likely to address a host of environmental concerns like methane migration into residential wells, fugitive methane emissions during the drilling process, produced water capture, storage and recycling. These issues will lead to technical solutions, but likely at a higher cost.

Nuclear Fuel

To provide fuel for Duke Energy Carolinas' nuclear fleet, the Company maintains a diversified portfolio of natural uranium and downstream services supply contracts from around the world.

Requirements for uranium concentrates, conversion services and enrichment services are primarily met through a portfolio of long-term supply contracts. The contracts are diversified by supplier, country of origin and pricing. In addition, Duke Energy Carolinas staggers its contracting so that its portfolio of long-term contracts covers the majority of fleet fuel requirements in the near-term and decreasing portions of the fuel requirements over time thereafter. 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.

Due to the technical complexities of changing suppliers of fuel fabrication services, Duke Energy Carolinas generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

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.

B. RENEWABLE RESOURCES AND RENEWABLE ENERGY INITIATIVES

1. Overview of Planning Assumptions

Duke Energy Carolinas' plans regarding renewable energy resources within this IRP are based primarily upon the presence of existing renewable energy requirements as well as the potential introduction of additional renewable energy requirements in the future.

Regarding existing renewable requirements, the Company is committed to meeting the requirements of the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS). This is a statutory requirement enacted in 2007 mandating that Duke Energy Carolinas supply the equivalent of 12.5% of retail electricity sales in

North Carolina from eligible renewable energy resources and/or energy efficiency savings by 2021.

With respect to potential new renewable energy portfolio standard requirements, the Company's plans in this IRP account for the possibility of future requirements that will result in additional renewable resource development beyond the NC REPS requirements. Renewable requirements have been adopted in many states across the nation, and have also been contemplated as a federal measure and by members of the legislature in South Carolina. As such, the Company believes it is reasonable to plan for additional renewable requirements within the IRP beyond what presently exists with the NC REPS requirements.

Although there are many potential assumptions that could be made regarding such future renewable requirements, the Company has assumed in this IRP that a new legislative requirement (imposed by either federal or state level legislation) would be implemented in the future that would result in additional renewable resource development in South Carolina. For planning purposes, it is assumed that the requirement would be similar in many respects to the NC REPS requirement, but with a different implementation schedule. Specifically, the Company has assumed that this requirement would have an initial 3% milestone in 2016 and would gradually increase to a 12.5% level by 2030. Similar to NC REPS, this assumed legislative requirement would incorporate both renewable energy and energy efficiency, as well as a limited capability to utilize out of state unbundled purchases of Renewable Energy Certificates (REC or RECs). Further, this assumed requirement would have a solar set-aside requirement comparable to that in NC REPS, but would not contain any additional set-asides such as the poultry waste or swine waste set-aside requirements that are part of NC REPS. Finally, no assumptions related to a cost-cap feature that may limit development of renewables and ultimate cost to customers were made with this assumed legislation, whereas the Company's projections of renewable resource development for NC REPS are governed by the statutory cost caps within the law.

The Company has assessed the current and potential future costs of renewable and traditional technologies and, based on this analysis, the IRP modeling process shows that, for the most part, the amount of renewable energy resources that will be developed over the planning horizon will be defined by the existing and anticipated statutory renewable energy requirements described above. In other words, the IRP modeling does not indicate any material quantity of renewable resource development over and above the required levels due to lack of cost-effectiveness of these resources.

2. Summary of Expected Renewable Resource Capacity Additions

Based on the planning assumptions noted above regarding current and potential future renewable energy requirements, the Company projects that a total of approximately 800 MW (nameplate) of renewable energy resources will be interconnected to the Duke Energy Carolinas system by 2023, with that figure growing to approximately 884 MW by the end of the planning horizon in 2031. Actual results could vary substantially, with key drivers of different outcomes being future legislative requirements; relative costs of various renewable technologies in relation to traditional technologies; and various impediments impacting the development of various resources including permitting requirements, transmission and interconnection issues, or other matters.

It should be noted that many renewable technologies are intermittent in nature and that they therefore may not be contributing energy or capacity benefits to the Company's load requirements at any particular point in time. The details of the forecasted capacity additions, including both nameplate capacity and the expected contribution towards the Company's peak load needs, are summarized in Table 5.E below.

Table 5.E Expected Renewable Resource Capacity Additions

Renewables								
	MW Contribution to Summer Peak				MW Nameplate			
Year	Wind	Solar	Biomass	Total	Wind	Solar	Biomass	Total
2011	15.0	12	20	46	100	24	20	143
2012	0.0	12	29	41	0	24	29	53
2013	0.0	12	33	44	0	24	33	56
2014	15.0	12	89	116	100	24	89	213
2015	15.6	21	91	128	104	42	91	237
2016	47.8	22	179	249	318	45	179	542
2017	47.8	23	180	250	319	45	180	543
2018	49.7	24	230	304	332	49	230	610
2019	50.7	25	265	341	338	51	265	654
2020	53	28	296	376	352	56	296	703
2021	51	26	295	372	339	51	295	686
2022	55	28	344	427	367	57	344	767
2023	55	36	346	437	368	72	346	786
2024	55	36	347	439	369	73	347	789
2025	58	36	384	478	389	73	384	846
2026	61	41	386	488	406	81	386	874
2027	59	37	385	481	392	73	385	851
2028	59	37	388	484	393	74	388	855
2029	62	41	391	493	411	82	391	884
2030	62	41	391	493	411	82	391	884
2031	62	41	391	493	411	82	391	884

3. Changes in Renewable Planning Assumptions Since 2010

The renewable energy requirements (existing and anticipated) that are assumed in this IRP are largely similar to what was assumed in the Company's 2010 IRP. However, the Company's expectations regarding how those requirements will be met have evolved. Changes from the prior year are summarized here.

As compared to last year's IRP, the Company has assumed the development and interconnection of more wind resources over the planning horizon, along with a corresponding reduction in the development of biomass resources. The projected increase in wind resources is driven by the Company's observations that land-based wind developers are presently pursuing projects of significant size in North Carolina. The Company believes it is reasonable to expect that land-based wind will be developed in both North and South Carolina within the planning horizon to a degree that exceeds what was expected a year ago. The Company also has observed that opportunities currently exist, and may continue to exist, to transmit land-based wind energy resources into the Carolinas from other regions, which could supplement the amount of wind that could be developed within the Carolinas.

The Company's expectations regarding biomass resources are somewhat more modest, particularly in the near-term, than a year ago. This reduction in reliance upon biomass is in part due to uncertainties around the developable amount of such resources in the Carolinas, uncertainties related to the EPA's various rulemaking proceedings, and the projected availability of other forms of renewable resources to offset the needs for biomass. Because of the increased contributions from wind, which is an intermittent resource, versus biomass, which more closely mirrors a baseload resource, the Company has an additional system peak need in 2015.

In this current IRP, the Company also projects it will utilize more short term contracts than was assumed a year ago in the later years of the planning horizon. This is driven by a combination of factors, including an assumption that in the outer years of the planning horizon (e.g. beyond ~2023) there will be a more liquid market where the Company could engage in shorter term purchases of qualifying renewable energy or RECs to meet its REPS compliance needs. While the characteristics of this more distant portion of the planning horizon are difficult to ascertain with confidence, the Company projects that shorter term contracts may in fact be a necessity in order to effectively manage expenditures in accordance with the NC REPS statutory per-account cost caps, which remain fixed after 2015.

Through 2023, the Company's plans are based predominately on resources that are longer term in nature, with a gradual increase in the total amount of renewable resources over this time period. Beyond 2023, Duke Energy Carolinas forecasts that it will need additional resources to maintain compliance with NC REPS, with at least some of those resources being secured under short-term agreements. In this IRP, short-term agreements are assumed to come from a combination of unbundled in-state RECs from resources of various types, potentially including thermal RECs from Combined Heat and Power (CHP) facilities, as well as bundled energy and REC purchases of various resource types.

4. Further Details on Compliance with NC REPS

A more detailed discussion of the Company's plans to comply with the NC REPS requirements can be found in the Company's NC REPS Compliance Plan (Compliance Plan), which the Company submits to the NCUC as a separate document within the same docket as this IRP.

Details of that Compliance Plan are not duplicated here, although it is important to note that various details of the NC REPS law have impacts on the amount of energy and capacity that the Company projects to obtain from renewable resources to help meet the Company's long term resource needs. For instance, NC REPS contains several detailed parameters, including technology specific set-aside requirements for solar, swine waste, and poultry waste resources; capabilities to utilize EE savings and unbundled REC purchases from in-state or out-of-state resources, and RECs derived from thermal (non-electrical) energy; and a statutory spending limit to protect customers from cost increases stemming from renewable energy procurement or development. Each of these features of NC REPS has implications on the amount of renewable energy and capacity the Company forecasts to obtain over the planning horizon of this IRP. Additional details on NC REPS compliance can be found in the Company's Compliance Plan.

C. SUPPLY-SIDE RESOURCE SCREENING

For purposes of the 2011 IRP, the Company considered a diverse range of technology choices utilizing a variety of different fuels, including pulverized coal units with and without carbon capture sequestration, Integrated Gasification Combined Cycle (IGCC) with and without carbon capture sequestration, CTs, CC units, and nuclear units. In addition, Duke Energy Carolinas considered renewable technologies such as wind, biomass, and solar in this year's screening analysis. Landfill gas was not included in this screening process due to limited availability. However, to the extent that landfill gas is available, it is competitive from a cost perspective with conventional baseload technologies.

For the 2011 IRP screening analyses, the Company screened technology types within their own respective general categories of baseload, peaking/intermediate, and renewable, with the ultimate goal of screening being to pass the best alternatives from each of these three categories to the integration process. As in past years, the reason for performing these initial screening analyses is to determine the most viable and cost-effective resources for further evaluation. This initial screening evaluation is necessary because of the size of the problem to be solved and computer execution time limitations of the System Optimizer capacity model (described in detail in Chapter 8).

1. Process Description

Information Sources

The cost and performance data for each technology being screened is based on research and information from several sources. These sources include, but may not be limited to the following: Duke Energy's New Generation, Emerging Technologies, Duke Energy Analytical and Investment Engineering Teams, the EPRI Technology Assessment Guide (TAG®), and studies performed by and/or information gathered from external sources. In addition, fuel and operating cost estimates are developed internally by Company personnel, or from other sources such as those mentioned above, or a combination of the two. The EPRI information along with any information or estimates from external studies are not site-specific, but generally reflect the costs and operating parameters for installation in the Carolinas.

Finally, every effort is made to ensure, as much as possible, that the cost and other parameters are current 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, remains very difficult.

Technical Screening

The first step in the Company's supply-side screening process for the IRP was a technical screening of the technologies to eliminate those that have technical limitations, commercial availability issues, or are not feasible in the Duke Energy Carolinas service territory. A brief explanation of the technologies excluded at this point and the logic for their exclusion follows:

- Geothermal was eliminated because there are no suitable geothermal resources in the region to develop into a power generation project.

- Advanced Battery storage technologies (Lead acid, Li-ion, Sodium Ion, Zinc Bromide, Fly wheels, pump storage) 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 within Duke Energy, but this technology is generally not commercially available on a larger utility scale. Currently Duke Energy is installing 36 MW advanced acid lead batteries at the Notrees wind farm in Texas that is scheduled for start-up in 2012. Duke Energy has other storage system test stations at the Envision Energy Center in Charlotte, which specifically include 2 Community Energy Storage (CES) systems of 24 kW.
- Compressed Air Energy Storage (CAES), although demonstrated on a utility scale and generally commercially available, is not a widely applied technology and remains relatively expensive. The high capital requirements for these resources arise from the fact that suitable sites that possess the proper geological formations and conditions necessary for the compressed air storage reservoir are relatively scarce.
- Small and medium nuclear reactors are generally limited to less than 300 MW. The NRC has not licensed any smaller nuclear reactor designs at this point in time. Several designs including those by General Electric (GE), Babcock & Wilcox (B&W) and Westinghouse may seek licensing in 2012 and 2013.
- 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 kW to tens of MW in the long-term. 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.
- Poultry waste and hog waste digesters remain relatively expensive and are capable of generating 500 – 600 MWh or less annually. Research, development, and demonstration continue, but these technologies are generally not commercially available on a larger utility scale. The Company's detailed quantitative analysis in this IRP included evaluation of purchased power agreements for poultry waste-to-energy facilities due to the poultry waste set-aside requirements in the NC REPS.
- Off-shore wind, although demonstrated on a utility scale and commercially available, is not a widely applied technology and not easily permittable.

This technology remains expensive and has yet to actually be constructed anywhere in the United States. Duke Energy Carolinas has collaborated with the University North Carolinas to continue studying off-shore wind on the Carolinas coastal area.

- Combined cycle G-Class technology has been demonstrated on a utility scale and is comparable to the F-Class in terms of efficiency. Its development remains limited due to lack of experience. The combined cycle G-class technology is larger in size and is designed to operate primarily as base load and not suitable for the anticipated cycling operation.

Economic Screening

In the supply-side screening analysis, the Company used the same fuel prices for coal and natural gas, and NO_x, SO_2, and CO_2 allowance prices as those utilized downstream in the System Optimizer analysis (discussed in Chapter 8). The Company derived its biomass fuel price from various vendor fuel and delivery prices. The biomass fuel price may vary in the future as more utilities begin to use biomass fuel.

The Company screened all technologies using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves. The screening within each general class, as well as the final screening across the general classes used a spreadsheet-based screening curve model developed by Duke Energy. This model is considered proprietary, confidential and competitive information by Duke Energy.

This screening curve analysis model calculates the fixed costs associated with owning and maintaining a technology type over its lifetime and computes a levelized fixed $/kW-year value. This calculated value represents the cost of operating the technology at a zero capacity factor or not at all, *i.e.*, the Y-intercept on the graph (see the General Appendix for individual graphs). The model then calculates the variable costs, such as fuel, variable O&M, and emission costs associated with operating the technology at 100% capacity factor, or at full load, over its lifetime and the present worth is computed back to the start year. This levelized operating $/kW-year is next added to the levelized fixed $/kW-year value to arrive at a total owning and operating value at 100% utilization in $/kW-year. Then a straight line is drawn connecting the two points. This line represents the technology's "screening curve".

The Company repeats this process for each supply technology to be screened resulting in a family of lines (curves). The lower envelope along the curves represents the least costly supply options for various capacity factors or unit utilizations. Some of the renewable resources that have known limited energy output, such as wind and solar, have screening curves limited to their expected operating range on the individual graphs.

Lines that never become part of the lower envelope, or those that become part of the lower envelope only at capacity factors outside of their relevant operating ranges, have a very low probability of being part of the least cost solution, and generally can be eliminated from further analysis.

2. Screening Results

The results of the screening within each category are shown in Appendix C.

The Company passes on those technologies from each of the three general categories screened (Baseload, Peaking/Intermediate, and Renewables) which were the "best," i.e., the lowest levelized busbar cost for a given capacity factor range within each of these categories, to the quantitative analysis phase for further evaluation.

Duke Energy Carolinas included CC generation in the peaking intermediate screening curves for comparison purposes. However, based on the screen results, CC generation would also be cost effective as a base load technology.

The Company's model selected the following technologies for the quantitative analysis:

- Baseload – 800MW Supercritical Pulverized Coal
- Baseload – 630 MW IGCC
- Baseload – 2 x 1,117MW Nuclear units (AP1000)
- Peaking/Intermediate – 4x204MW CTs (7FA.05)
- Base Load/Intermediate/Peaking – 480 MW Unfired + 125MW Duct Fired + 45MW Inlet Evaporative Cooler Natural Gas CC
- Base Load/Intermediate/Peaking – 480 MW Unfired + 45MW Inlet Evaporative Cooler Natural Gas CC
- Renewable – 100 MW Woody Biomass
- Renewable – 150 MW Wind - On-Shore
- Renewable – 15 MW Landfill Gas
- Renewable – 25 MW Solar PV

3. Unit Size

The unit sizes selected for planning purposes generally are the largest technologies available today because they generally offer lower $/kW installed capital costs due to economies of scale. However, the true test of whether a resource is economic depends on the economics of an overall resource plan that contains that resource (including fuel costs, O&M costs, emission costs, *etc*.), not merely on the $/kW cost. In the case of very large unit sizes such as those utilized for the nuclear and/or IGCC technology types, if these are routinely selected as part of a least cost plan, joint ownership can and may be evaluated and pursued.

4. Cost, Availability, and Performance Uncertainty

Supply-side alternative project scope and estimated costs used for planning purposes for conventional technology types, such as simple-cycle CT units and CC units, are relatively well known and are estimated in the TAG® and can be obtained from architect and engineering (A&E) firms and/or equipment vendors. The Company also uses its experience with the scope and costs for such resources to confirm the reasonableness of the estimates. The cost estimates include step-up transformers and a substation to connect with the transmission system. Since any additional transmission costs would be site-specific and specific sites requiring additional transmission are unknown at this time, typical values for additional transmission costs were also added to the alternatives. For natural gas units, gas pipeline costs were also included in the cost estimates. The unit availability and performance of conventional supply-side options is also relatively well known and the TAG®, A&E firms and/or equipment vendors are sources of estimates of these parameters.

5. Lead Time for Construction

The estimated construction lead time and the lead time used for modeling purposes for the proposed simple-cycle CT units is about two years. For the CC units, the estimated lead time is about two to three years. For coal units, the lead time is approximately five years. For nuclear units, the lead time is approximately five years. However, the time required to obtain regulatory approvals and environmental permits adds uncertainty to the process, so Company judgment is also incorporated into the analysis as necessary.

6. RD&D Efforts and Technology Advances

New energy and technology alternatives will be necessary to ensure a long-term sustainable electric future. Duke Energy Carolinas' research, development, and delivery (RD&D) activities enable Duke Energy Carolinas to track new options including modular and potentially dispersed generation systems (small and medium nuclear reactors), CTs, and advanced fossil technologies. The Company places emphasis on providing information, assessment tools, validated technology, demonstration/deployment support, and RD&D investment opportunities for planning and implementing projects utilizing new power generation technology to assure a strategic advantage in electricity supply and delivery. Duke Energy is also a member of EPRI.

Within the planning horizon of this forecast, Duke Energy Carolinas expects that significant advances will continue to be made in CT technology. Advances in stationary industrial CT technology should result from ongoing research and development efforts to improve both commercial and military aircraft engine efficiency and power density, as well as expanding research efforts to burn more hydrogen-rich fuels. The ability to burn hydrogen-rich fuels will enable very high levels of CO_2 removal and shifting in the syngas utilized in IGCC technology, thereby enabling a major portion of the advancement necessary for a significant reduction in the carbon footprint of this coal-based technology.

7. Coordination with Other Utilities

Decisions concerning coordinating the construction and operation of new units with other utilities or entities are dependent on a number of factors including the size of the unit versus each utility's capacity requirement and whether the timing of the need for facilities is the same. To the extent that units larger than Duke Energy Carolina's requirements become economically viable in a plan, co-ownership can be considered at that time. Coordination with other utilities can also be achieved through purchases and sales in the bulk power market.

D. WHOLESALE AND QF PURCHASED POWER AGREEMENTS

Duke Energy Carolinas is an active participant in the wholesale market for capacity and energy. The Company has issued RFPs for purchased power capacity over the past several years, and has entered into purchased power arrangements for over 2,000 MWs over the past 10 years. In addition, Duke Energy Carolinas has contracts with a number of Qualifying Facilities (QFs). Table 5.F shows both the purchased power capacity obtained through RFPs as well as the larger QF agreements. See Appendix I for additional information on all purchases from QFs.

Table 5.F
Wholesale Purchases & Purchased Power Agreements

SUPPLIER	CITY	STATE	SUMMER FIRM CAPACITY (MW)	WINTER FIRM CAPACITY (MW)	CONTRACT START	CONTRACT EXPIRATION
Catawba County	Newton	NC	4	4	8/23/1999	8/22/2014
Concord Energy, LLC	Concord	NC	9	9	TBD	12/31/2031
Davidson Gas Producers, LLC	Lexington	NC	2	2	12/1/2010	12/31/2030
Gas Recovery Systems, LLC	Concord	NC	3	3	2/1/2010	12/31/2030
Gaston County	Dallas	NC	4	4	TBD	12/31/2021
Greenville Gas Producers, LLC	Greer	SC	3	3	8/1/2008	Ongoing
Lockhart Power Company	Wellford	SC	2	2	4/1/2011	12/31/2020
MP Durham, LLC	Durham	NC	3	3	9/18/2009	12/31/2029
Salem Energy Systems, LLC	Winston-Salem	NC	4	4	7/10/1996	Ongoing
WMRE Energy, LLC	Kernersville	NC	2	2	3/31/2011	12/31/2026
Mayberry Solar LLC	Mt. Airy	NC	1	0	9/1/2011	8/31/2026
Solar Green Development, LLC	Charlotte	NC	1	0	10/1/2011	9/30/2026
Solar Green Development, LLC	Mint Hill	NC	1	0	12/1/2011	11/30/2026
SunEd DEC1, LLC	Lexington	NC	8	0	12/1/2009	12/31/2030
Other PV	Various	NC	1	0	Various	Ongoing
Cherokee County Cogeneration Partners, L.P.	Gaffney	SC	88	95	7/1/1996	6/30/2013
Northbrook Carolina Hydro, LLC	Various	NC & SC	6	6	12/4/2006	Ongoing
Town of Lake Lure	Lake Lure	NC	3	3	2/21/2006	2/20/2011
Misc. Small Hydro/Other	Various	Both	6	6	Various	Assumed Evergreen
Other Wholesale	Various	Both	119	119	Various	Ongoing

Notes: Solar PV Firm Capacity represents 50% contribution to peak

Summary of Wholesale and QF Purchased Power Commitments
(as of July 1, 2011)

	SUMMER 11	WINTER 10/11
Non-Utility Generation		
Traditional	102 MW	109 MW
Renewable *	47 MW	36 MW
Duke Energy Carolinas allocation		
of SEPA capacity	37.8 MW	37.8 MW
Other-Wholesale	81.3 MW	81.3 MW
Total Firm Purchases	268.1 MW	264.1 MW

* Renewable includes landfill gas and solar PV

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 resource, 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 CC projects. The consideration of purchased power options was described in the Company's CPCN application for these facilities and addressed in testimony. The NCUC issued the CPCNs for the Buck and Dan River CC projects in June 2008.

The Company also issued a 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 2011 IRP plans included approximately 2,890 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 new self-build capacity, purchased power, additional DSM or any combination of the three.

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 with 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.

6. ENVIRONMENTAL COMPLIANCE

Legislative and Regulatory Issues

Duke Energy Carolinas, which is subject to the jurisdiction of federal agencies including the Federal Energy Regulatory Commission (FERC), 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 the existing generation and choices for new generation.

Air Quality

Duke Energy Carolinas is required to comply with numerous state and federal air emission regulations such as the current Clean Air Interstate Rule (CAIR) NO_x and SO_2 cap-and-trade program, and the 2002 North Carolina Clean Smokestacks Act (NC CSA).

As a result of complying with the NC CSA, Duke Energy Carolinas will reduce SO_2 emissions by approximately 75 percent by 2013 from 2000 levels. The law also required additional reductions in NO_x emissions in 2007 and 2009, beyond those required by the CAIR rule, which Duke Energy Carolinas has achieved. 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 Charts 6.A and 6.B show Duke Energy Carolinas' NO_x and SO_2 emissions reductions to comply with the 2002 NC CSA requirements and actual emission through 2010.

Chart 6.A

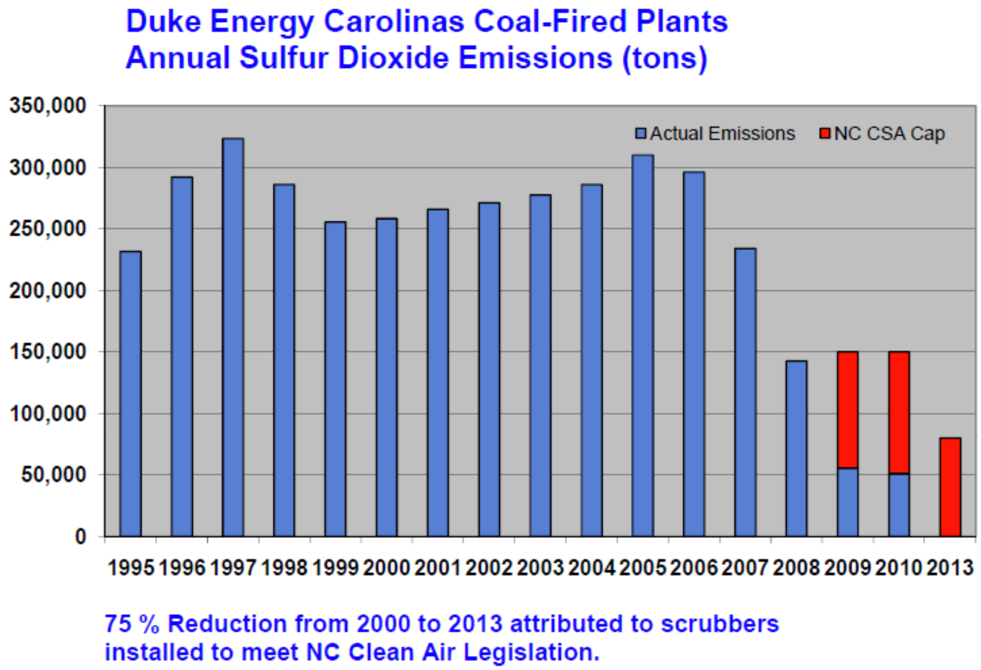
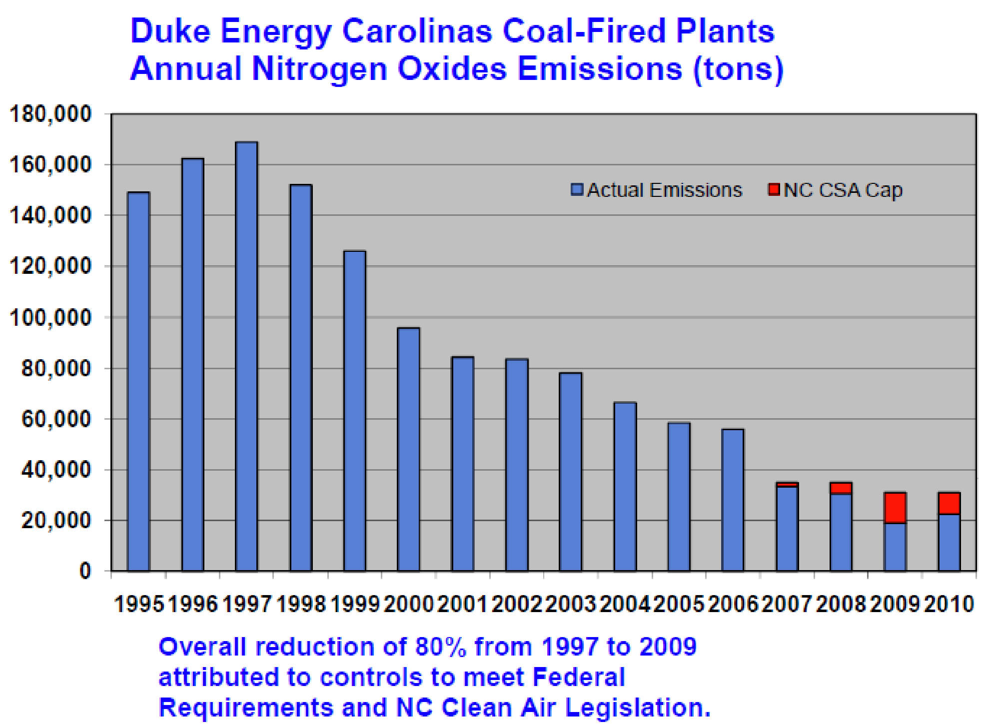


Chart 6.B



In addition to current programs and regulatory requirements, several new regulations are in various stages of implementation and development that will impact operations for

Duke Energy Carolinas in the coming years. Some of the major rules include:

Cross-State Air Pollution Rule – Replacement for Clean Air Interstate Rule (CAIR)

The EPA finalized its CAIR in May 2005. The CAIR limits total annual and summertime NO_x emissions and annual SO_2 emissions from electric generating facilities across the Eastern U.S. through a two-phased cap-and-trade program. Phase 1 began in 2009 for NO_x and in 2010 for SO_2. In July 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. In December 2008, the D.C. Circuit issued a decision remanding the CAIR to the EPA, allowing CAIR to remain in effect until EPA develops new regulations.

In August 2010, EPA published its proposed Transport Rule to replace the CAIR. On July 6, 2011, EPA issued the final rule, now known as the Cross-State Air Pollution Rule (CSAPR). The CSAPR replaces the CAIR and establishes state-level annual SO_2 and NO_x caps that take effect on January 1, 2012, and state-level ozone-season NO_x caps that take effect on May 1, 2012. The cap levels decline in 2014 in North Carolina, but remain constant in South Carolina. The CSAPR allows limited interstate and unlimited intrastate allowance trading. The final rule is significantly different from the original proposal. As a result, Duke Energy Carolinas has not had adequate time to prepare for these changes. Immediate steps are planned to develop strategies to minimize impacts while complying with the CSAPR. Duke Energy Carolinas will be particularly challenged to comply with annual and ozone season NO_x allocations in North Carolina beginning in 2014, as well as for both SO_2 and NO_x in South Carolina beginning in 2012. Additional revisions to the CSAPR could be developed by EPA that would incorporate the more stringent ozone and particulate matter NAAQS, which are in varying stages of development by the EPA.

Utility Boiler Maximum Achievable Control Technology (MACT)

In May 2005, the EPA issued 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 (CAA) section 111(d). It also established a nationwide mercury cap-and-trade program covering existing and new coal-fired power units.

In February 2008, the D.C. Circuit Court of Appeals issued its opinion, vacating the CAMR. EPA then began the process of developing a rule to replace the CAMR. The replacement rule, the Utility Boiler MACT, will create emission limits for hazardous air pollutants (HAPs), including mercury, from coal-fired and oil-fired power plants. Duke Energy completed work in 2010 as required for EPA's Utility MACT Information Collection Request (ICR). The ICR required collection of mercury and HAPs emissions data from numerous Duke Energy Carolinas facilities for use by EPA in developing the MACT rule. EPA published a proposed MACT rule (now referred to by EPA as the "Toxics Rule") on May 3, 2011 and expects to finalize it in November 2011. As proposed, the Toxics Rule is expected to require compliance with new emission limits in early 2015, with possible one-year extensions that a permitting authority can grant on a case-by-case basis. While the implications of the MACT rule are not fully known at this time, Duke Energy Carolinas is likely to face challenges from the rule which could include consideration of retiring certain assets rather than installing controls to comply.

Reciprocating Internal Combustion Engine (RICE) Maximum Achievable Control Technology (MACT)

EPA also has finalized the Reciprocating Internal Combustion Engine MACT (RICE MACT) which had an effective date of May 3, 2010. The RICE MACT requires certain existing engines such as those used for power production to retrofit with catalyst beds. While the RICE MACT has limited direct impact on the Company's operations, it does impact customers and suppliers of Duke Energy Carolinas and impacts purchasing agreements for the overall power supply portfolio. Non-emergency sources are most likely to be required to retrofit to comply with RICE standards. Engines used for emergency purposes, such as fire pumps and generators have limitations on operations and other less stringent requirements under the RICE MACT. These emergency-use engines will mostly be impacted with additional maintenance requirements, such as inspections, record keeping and periodic maintenance requirements. All engines will have to be in compliance by May 3, 2013, with costs to comply occurring in the 2011-2012 timeframe. This has impacted the Company's expected demand response program reductions identified in this IRP.

National Ambient Air Quality Standards (NAAQS)

8 Hour Ozone Standard

In March 2008 EPA revised the 8-hour ozone standard by lowering it from 84 to 75 parts per billion (ppb). In September 2009, EPA announced a decision to reconsider the 75 ppb standard. The decision was in response to a court challenge from environmental groups and EPA's belief that a lower standard was justified.

EPA issued a proposed rule on January 7, 2010 in which EPA proposed to replace the existing standard with a new standard between 60 and 70 ppb. EPA plans to issue a final rule in the fall of 2011. The schedule for implementing a new standard is somewhat uncertain until EPA finalizes the rule as well as its plans for implementation. It is estimated, however, that State Implementation Plans (SIP) could be due by December

2014, with possible attainment dates for most areas in the 2018 timeframe. Additional controls could be required by the 2018 ozone season. Until the states develop implementation plans, only an estimate can be developed of the potential impact to Duke Energy Carolina's generation fleet. A standard in the 60 to 70 ppb range is considered very stringent and will likely result in numerous non-attainment area designations.

SO_2 Standards

In November 2009, EPA proposed a rule to replace the 24-hour and annual primary SO_2 NAAQS with a 1-hour SO_2 standard. EPA finalized its new 1-hr standard of 75 ppb in June 2010. EPA will have 2 years (June 2012) to designate areas relative to their attainment status with the new standard. States with non-attainment areas will have until the January 2014 to submit their SIPs. Initial attainment dates are expected to be the summer of 2017. EPA has not yet indicated when any required controls might need to be in place, but is expected by late-2016. EPA will base its nonattainment designations on monitored air quality data as well as on dispersion modeling. All power plants will be modeled by the NC and SC Department of Air Quality and are therefore potential targets for additional SO_2 reductions, even if there is no monitored exceedance of the standard. In addition, EPA is proposing to require states to relocate some existing monitors and to add some new monitors. Although these monitors will not be used by EPA to make the initial nonattainment designations, they will play a role in identifying possible future nonattainment areas.

Particulate Matter (PM) Standard

On September 21, 2006, the EPA announced its decision to revise the $PM_{2.5}$ NAAQS standard. The daily standard was reduced from 65 ug/m^3 (micrograms per cubic meter) to 35 ug/m^3. The annual standard remained at 15 ug/m^3.

EPA finalized designations for the 2006 daily standard in October 2009, which did not include any nonattainment areas in the Duke Energy Carolinas service territory. On February 24, 2009, the D.C Circuit unanimously remanded to EPA the Agency's decision to retain the annual 15 ug/m^3 primary $PM_{2.5}$ NAAQS and to equate the secondary $PM_{2.5}$ NAAQS with the primary NAAQS. EPA must now undertake new rulemaking to revise the standards consistent with the Court's decision. EPA's current timeline indicates that it will propose a $PM_{2.5}$ rule in fall 2011 and possibly finalize a rule around mid-2012. The likely outcome of EPA's ongoing review will be a tightening of the primary daily and annual $PM_{2.5}$ NAAQS along with the creation of a separate secondary $PM_{2.5}$ NAAQS. The current annual and daily $PM_{2.5}$ standards alone are not driving any emission reductions at Duke Energy Carolinas facilities. The reduction in SO_2 and NO_x emissions to address the current annual standard are being addressed through CAIR.

Reductions to address the current daily standard will be addressed as part of the CSAPR that EPA developed to replace CAIR (the CSAPR will continue to address reductions needed for the current annual standard).

Greenhouse Gas Regulation

The EPA has been active in the regulation of greenhouse gases (GHGs). In May 2010, the EPA finalized what is commonly referred to as the Tailoring Rule, which sets the emission thresholds to 75,000 tons/year of CO_2 for determining when a source is potentially subject to Prevention of Significant Deterioration (PSD) permitting for GHGs. The Tailoring Rule went into effect beginning January 2, 2011. Being subject to PSD permitting requirements for CO_2 will require a Best Available Control Technology (BACT) analysis and the application of BACT for GHGs. BACT will be determined by the state permitting authority. Since it is not known if, or when, a Duke Energy Carolinas generating unit might undertake a modification that triggers PSD permitting requirements for GHGs and exactly what might constitute BACT at a particular point in time, the potential implications of this regulatory requirement are presently unknown.

In early 2011, EPA entered into a settlement agreement to issue New Source Performance Standards for GHG emissions from new and modified fossil fueled electric generating units (EGUs) and emission guidelines for existing EGUs. The agreement calls for regulations to be proposed by September 30, 2011 and to be finalized by 2012.

It is currently not known if or when any federal climate change legislation limiting GHG emissions might be enacted.

Water Quality and By-product Issues

CWA 316(b) Cooling Water Intake Structures

Federal regulations in Section 316(b) of the Clean Water Act may necessitate cooling water intake modifications and/or cooling towers for existing facilities to minimize impingement and entrainment of aquatic organisms. All Duke Energy Carolina's coal and nuclear generating stations are potentially affected sources under that rule.

EPA issued a proposed rule on April 20, 2011 and expects to finalize the rule in July 2012. Depending upon a station's National Pollutant Discharge Elimination System (NPDES) permit renewal schedule, compliance with the rule could begin as early as mid-2015.

EPA's proposed rule lists four options with a preference for one option. The preferred option impacts all facilities with a design intake flow greater than 2 million gallons per day (mgd). In order to meet fish impingement standards, intake screen modifications are likely to be needed for nearly all plant intakes. EPA has not mandated the use of cooling towers as "Best Technology Available" to address entrainment requirements. However, site specific studies are proposed by the rule in order to address best technology options for complying with the entrainment requirements. These studies could begin as early as 2013.

Steam Electric Effluent Guidelines

In September 2009, EPA announced plans to revise the steam electric effluent guidelines. In order to assist with development of the revised regulation, EPA issued an Information Collection Request (ICR) to gather information and data from nearly all steam-electric generating facilities. The ICR was completed and submitted to EPA in October 2010. The regulation is to be technology-based, in that limits are based on the capability of technology. The primary focus of the revised regulation is on coal-fired generation, thus the major areas likely to be impacted are FGD wastewater treatment systems and ash handling systems. The EPA may set limits that dictate certain FGD wastewater treatment technologies for the industry and may require dry ash handling systems be installed. Following review of the ICR data, EPA plans to issue a draft rule in July 2012 and a final rule in January 2014. After the final rulemaking, effluent guideline requirements will be included in a station's NPDES permit renewals. Thus, requirements to comply with NPDES permit conditions may begin as early as 2017 for some facilities. The length of time allowed to comply will be determined through the permit renewal process.

Coal Combustion Residuals

Following Tennessee Valley Authority's Kingston ash dike failure in December 2008, EPA began an effort to assess the integrity of ash dikes nationwide and to begin developing a rule to manage coal combustion residuals (CCRs). CCRs include fly ash, bottom ash and FGD byproducts (gypsum). Since the 2008 dike failure, numerous ash dike inspections have been completed by EPA and an enormous amount of input has been received by EPA, as it developed proposed regulations.

In June 2010, EPA issued its proposed rule regarding CCRs. The proposed rule offers two options: (1) a hazardous waste classification under Resource Conservation and Recovery Act (RCRA) Subtitle C; and (2) a non-hazardous waste classification under RCRA Subtitle D, along with dam safety and alternative rules. Both options would require strict new requirements regarding the handling, disposal and potential re-use ability of CCRs. The proposal could result in more conversions to dry handling of ash, more landfills, closure of existing ash ponds and the addition of new wastewater treatment systems. Final regulations are not expected until 2012 or 2013. EPA's regulatory classification of CCRs as hazardous or non-hazardous will be critical in developing plans for handling CCRs in the future. The impact to Duke Energy Carolinas of this regulation as proposed is still being assessed. The schedule for compliance will depend upon when EPA finalizes a rule and the rule requirements.

7. TRANSMISSION AND DISTRIBUTION

A. Transmission System Adequacy

Duke Energy Carolinas monitors the adequacy and reliability of its transmission system and interconnections through internal analysis and participation in regional reliability groups. Internal transmission planning looks 10 years ahead at available generating resources and projected load to identify transmission system upgrade and expansion requirements. Corrective actions are planned and implemented in advance to ensure continued cost-effective and high-quality service. The Duke Energy Carolinas' transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with Duke Energy Carolinas' Transmission Planning Guidelines for voltage and thermal loading. The annual screening uses methods that comply with SERC policy and NERC Reliability Standards and the screening results identify the need for future transmission system expansion and upgrades and are used as inputs into the Duke Energy Carolinas – Power Delivery optimization process. The Power Delivery optimization process evaluates problem-solution alternatives and their respective priority, scope, cost, and timing. The optimization process enables Power Delivery to produce a multi-year work plan and budget to fund a portfolio of projects which provides the greatest benefit for the dollars invested.

Duke Energy Carolinas currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Guidelines and the FERC Open Access Transmission Tariff (OATT). The Company performs studies to ensure transfer capability is acceptable to meet reliability needs and customers' expected use of the transmission system. The Power Delivery optimization process is also used to manage projects for improvement of transfer capability.

The SERC audits Duke Energy Carolinas every three years for compliance with NERC Reliability Standards. Specifically, the audit requires Duke Energy Carolinas to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the Company's annual compliance filing certifications. SERC completed a full audit in April 2008 and also completed a "spot check" audit of selected standards in August 2009. Duke Energy Carolinas was found compliant in all areas of the audit. SERC also conducted a full audit in May 2011. The 2011 audit results are not yet publically available.

Duke Energy Carolinas participates in a number of regional reliability groups to coordinate analysis of regional, sub-regional and inter-control area transfer capability and interconnection reliability. The reliability groups' purpose is to:

- Assess the interconnected system's capability to handle large firm and non-firm transactions for purposes of economic access to resources and system reliability;
- Ensure that planned future transmission system improvements do not adversely affect neighboring systems; and
- Ensure the interconnected system's compliance with NERC Reliability Standards.

Regional reliability groups evaluate transfer capability and compliance with NERC Reliability Standards for the upcoming peak season and five- and ten-year periods. The groups also perform computer simulation tests for high transfer levels to verify satisfactory transfer capability.

B. Transmission System Emerging Issues

Looking forward, several items that have the potential to impact the planning of the Duke Energy Carolinas Transmission System include:

- Industry-approved revisions to the NERC Reliability Standards for transmission planning standards that are awaiting FERC approval.

- The FERC Final Order on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, issued in July 2011 under Docket No. RM10-23-000.

- Increased interest in the integration of variable renewable resources (e.g., wind) into the grid. The North Carolina Transmission Planning Collaborative and the DOE-funded Southeastern Offshore Wind Energy Infrastructure Project are performing studies in 2011 to assess the transmission impacts of significant off-shore wind development along the Southeast coast including North Carolina.

- The Eastern Interconnection Planning Collaborative (EIPC), which is a transmission study process that began in late 2009. The EIPC provides:

1. A mechanism to aggregate existing regional transmission plans in the Eastern Interconnection and assess them on an Eastern Interconnection wide basis; and
2. A framework to be able to perform technical analyses to inform state and federal government representatives and policy makers on important issues, such as future renewable resources and their impact on transmission infrastructure.

As of late July 2011, the EIPC is awaiting determination by its Stakeholder Steering Committee (SSC) of the three future scenarios they will request receive detailed analysis by the EIPC powerflow study group. The detailed analysis will determine the future transmission infrastructure required to support each of the three resource scenarios selected by the SSC.

- Duke Energy and Progress Energy are working towards a merger of the corporations and are targeting a closing by the end of 2011. The organizational structure and processes related to transmission planning in North Carolina are being discussed and evaluated by the management of the two companies.

8. SELECTION AND IMPLEMENTATION OF THE PLAN

A. RESOURCE NEEDS ASSESSMENT (FUTURE STATE)

To meet the future needs of Duke Energy Carolinas' customers, it is necessary for the Company to adequately 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 (see Reserve Margin discussion below). 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.

Reserve Margin Explanation and Justification

Reserve margins are necessary to help ensure the availability of adequate resources to meet load obligations due to consideration of customer demand uncertainty, unit outages, transmission constraints, and weather extremes. Many factors have an impact on the appropriate levels of reserves, including existing generation performance, lead times needed to acquire or develop new resources, and product availability in the purchased power market.

Duke Energy Carolinas' historical experience has shown that a 17 percent target planning reserve margin is sufficient to provide reliable power supplies, based on the prevailing expectations of reasonable lead times for the development of new generation, siting of transmission facilities, and procurement of purchased capacity. As part of the Company's process for determining its target planning reserve margins, Duke Energy Carolinas reviews whether the current target planning reserve margin is adequate in the prior period. From July 2006 through June 2011, generating reserves, defined as available Duke Energy Carolinas generation capacity plus the net of firm purchases less sales, never dropped below 450 MW. However, on June 1, 2011, the Company's generating reserves dropped to approximately 500 MWs due to above-normal temperatures and forced outages on several units. Since 1997, Duke Energy Carolinas has had sufficient reserves to meet customer load reliably with limited need for activation of interruptible programs. However, on June 1, 2011, 535 MWs of DSM were activated. The DSM Activation History in Appendix D illustrates Duke Energy Carolinas' limited activation of interruptible programs through June 2011.

Duke Energy Carolinas also continually reviews its generating system capability, level of potential DSM activations, scheduled maintenance, environmental retrofit equipment and environmental compliance requirements, purchased power availability, and transmission capability to assess its capability to reliably meet customer demand. There are a number of increased risks that need to be considered with regard to Duke Energy Carolinas' reserve margin target. These risks include: (1) the increasing age of existing units on the system; (2) the inclusion of a significant amount of renewables (which are generally less available than traditional supply-side resources) in the plan due to the enactment of the NC REPS; (3) uncertainty regarding the impacts associated with significant increases in the Company's energy efficiency and demand-side management programs; (4) longer lead times for building baseload capacity such as nuclear; (5) increasing environmental pressures, which may cause additional unit derates and/or unit retirements; and (6) increases in derates of units due to extreme hot weather and drought conditions. Each of these risks would negatively impact the resources available to provide reliable service to customers. Duke Energy Carolinas will continue to monitor these risks in the future and make any necessary adjustments to the reserve margin target in future plans.

Duke Energy Carolinas also assesses its reserve margins on a short-term basis to determine whether to pursue additional capacity in the short-term power market. As each peak demand season approaches, the Company has a greater level of certainty regarding the customer load forecast and total system capability, due to greater knowledge of near-term weather conditions and generation unit availability.

Duke Energy Carolinas uses adjusted system capacity[3], along with Interruptible DSM capability to satisfy Duke Energy Carolinas' NERC Reliability Standards requirements for operating and contingency reserves. Contingencies include events such as higher than expected unavailability of generating units, increased customer load due to extreme weather conditions, and loss of generating capacity because of extreme weather conditions such as the severe drought conditions in 2007.

Upon the completion of the merger between Duke Energy and Progress Energy, the combined system reserve margin will be comprehensively reviewed to determine if the reserve margin needs to be adjusted.

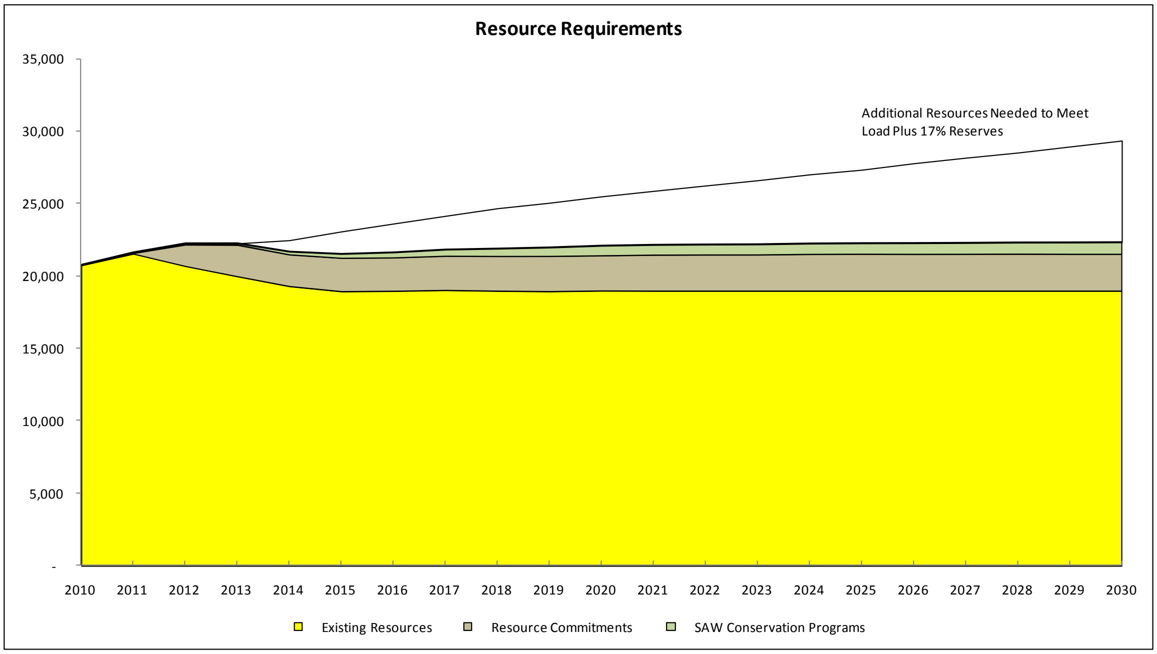
[3] Adjusted system capacity is calculated by adding the expected capacity of each generating unit plus firm purchased power capacity.

Load and Resource Balance

The following chart shows the existing resources and resource requirements needed to meet the Company's load obligation, plus the 17 percent target planning reserve margin. Beginning in 2011, existing resources, consisting of existing generation and purchased power to meet load requirements, total 20,777 MW. The load obligation plus the target planning reserve margin is 20,547 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, and expirations of purchased-power contracts. The need grows to approximately 3,090 MW by 2020 and to 7,030 MW by 2031. Assumptions made in the development of this chart include:

1. Cliffside Unit 6 is built by the summer of 2012 and therefore included in Resource Commitments;
2. Coal retirements associated with the Cliffside Unit 6 CPCN and Air Permit, Buck Units 5&6, and Lee Steam Station are included;
3. Retirement of the old fleet combustion turbines;
4. Conservation programs associated with the save-a-watt program are included;
5. DSM programs associated with the save-a-watt program are included;
6. Buck/Dan River combined cycle facilities are included in Resource Commitments;
7. Renewable capacity is built or purchased to meet the NC REPS

Chart 8.A
Load and Resource Balance



Cumulative Resource Additions to Meet a 17 Percent Planning Reserve Margin (MWs)

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Resource Need	0	0	0	790	1550	1990	2330	2790	3090	3410
Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Resource Need	3730	4080	4430	4780	5080	5520	5890	6220	6630	7030

B. 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 reliably meet customers' growing energy needs. In addition to assessing qualitative factors, the Company has also conducted a quantitative assessment using simulation models.

Duke Energy Carolinas tested a variety of sensitivities and scenarios against a base set of inputs for various resource mixes, allowing the Company to better understand how potentially different future operating environments due to 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 results of the Company's 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 unit at Cliffside Steam Station (Unit 6) is assumed to be in service in 2012, annually providing 5,700 GWh of baseload energy. Project implementation is underway for the new CC facilities at Buck and Dan River, with the facilities assumed to be operational in late 2011 and late 2012, respectively. In addition, Duke Energy Carolinas has included DSM, EE and renewable resources consistent with the Company's energy efficiency plan approved in North and South Carolina and to meet the NC REPS. For planning purposes, approximately 5% of retail sales in South Carolina would come from renewable energy, in addition to the energy efficiency programs, phased in from 2015 to 2031. The Company's analysis for the 2010 IRP demonstrated that approximately 200 MWs of nuclear uprates were cost effective and specific projects are being developed to be implemented in the 2011-2019 timeframe. For planning purposes, Lee Steam Station will be retired from coal fired generation and converted to natural gas generation in 2015. The increase in the peak generation need in 2015 is primarily due to increased load projections, updated assumptions regarding the energy impacts of CFLs and lower projected capacity impacts from DSM programs, as well as changes in the projected compliance portfolio relating to the NC REPS.

The Company's analysis of new nuclear capacity contained in the 2011 IRP focuses on the impact of various uncertainties such as load variations, nuclear capital costs, greenhouse gas and clean energy legislation, EPA regulations, fuel prices, and the availability of financing options such as federal loan guarantees (FLG).

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 EE 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 Company also developed high and low load forecast sensitivities to reflect a 95% confidence interval.

Nuclear Capital Costs: The Company varied the nuclear capital cost 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: The 2011 fundamental CO_2 allowance price forecast was lower primarily due to uncertainty of Congress to pass legislation. For the 2011 IRP, the Company evaluated a range of CO_2 prices based on various legislative cap and trade proposals used in 2009 and 2010 IRPs, in addition to potential Clean Energy legislation that does not have a CO_2 cap and trade mechanism, but relies upon a federal RPS.

Fuel Prices: The base case natural gas and coal price projections were based on Duke Energy's fundamental price forecasts, which are updated annually. The Company also evaluated a high cost fuel scenario, which reflects the impact of increased demand on natural gas and regulatory challenges to the coal mining industry. The lower cost fuel scenario represents a larger supply of domestic natural gas than currently assumed and a lower demand on coal.

Nuclear Financing Options: The nuclear cost referenced as "traditional financing" in the 2011 IRP includes state incentives, local incentives, and the ability to recover construction financing cost prior to commercial operation. Duke Energy Carolinas continues to believe that legislation allowing for timely collection of financing cost outside a general rate case during construction (nuclear financing legislation) is critical to the development of new nuclear plants. The Company plans to pursue nuclear financing legislation in the 2012 NC legislative session. Duke Energy Carolinas believes this legislation is important to demonstrate support for new nuclear development, and to allow utilities investing in new nuclear construction to maintain the strength of their respective balance sheets during construction to the benefit of their customers.

The nuclear cost referenced as "favorable financing" includes FLGs. The Company evaluated these credits as sensitivities because Duke Energy Carolinas' proposed Lee Nuclear Station does not currently qualify for these incentives. However, it is important to continue to include these benefits as sensitivities because it demonstrates how much expansion of these programs could lower the ultimate costs to customers, should the project qualify. There is federal legislative support for expanding these programs in the future.

Results

The results of the Company's 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, in part, with new EE and DSM programs, completing construction of the Buck, Dan River, and Cliffside Projects, completion of various fossil and hydro unit uprates, as well as pursuing nuclear uprates and renewable resources. However, additional resources will be needed as early as 2015 due to increased load projections, updated assumptions regarding the energy impacts of CFLs, lower projected capacity impacts from DSM programs, and changes in the projected renewable compliance portfolio. The Company's analysis continues to affirm the potential benefits of new nuclear capacity in the 2020 timeframe in a carbon-constrained future. The Company expects to receive the COL for the Lee Nuclear Station project in early 2013 and will make a final decision on the construction of the project based on the market conditions at that time, including the status of nuclear financing legislation in North Carolina.

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

This portfolio consisted of 2,890 MW[4] of new natural gas simple cycle capacity, 1,300 MW of CC capacity, 2,234 MW of new nuclear capacity, 987 MW of DSM, 727 MW of EE, and 484 MW of renewable resources. The selected portfolio specifically includes the Cliffside Unit 6, Buck CC, and Dan River CC projects.

However, the Company will likely face significant challenges relating to its resource planning in the future, such as specific challenges in (1) obtaining the necessary regulatory approvals to implement future demand-side, EE, and supply-side resources, (2) finding sufficient cost-effective, reliable renewable resources to meet the standard, (3) effectively integrating renewables into the resource mix, and (4) ensuring sufficient transmission capability for these resources. In light of the myriad of qualitative issues facing the Company relating to its 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'

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

energy needs reliably and economically while maintaining flexibility pertaining to long-term resource decisions.

On July 12, 2011, the NRC task force on the Japanese Fukishima Dai-ichi event noted it had not identified any issues that undermine confidence in the continued safety and emergency planning of U.S. nuclear plants. The task force review is ongoing and is likely to result in additional actions to enhance safety and preparedness of the U.S. nuclear fleet. The nuclear industry will ensure an exhaustive review of the events in Japan is completed and all possible lessons learned are applied to further improve nuclear safety. At this time, no significant impacts on new nuclear plant licensing are anticipated as a result of the events in Japan.

The Oconee Nuclear Station's (Oconee) current operating license expires in 2033, which is close to the end of our current IRP planning horizon. At this time, the Company has not made a decision concerning a second license extension for this plant. Oconee is a significant part of our generation portfolio representing over 2,500 MW of capacity and annual energy output of approximately 20,000 GWHrs. As such, it is important to start to examine the impacts of any potential retirement of Oconee to help the Company as it considers a second license extension, as well as incorporate these impacts into the resource planning process.

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 Table 8.A.

Table 8.A

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

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

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

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

Assumptions of Load, Capacity, and Reserves Table

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

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

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

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

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

7. Buck units 3-4 (113 MW) were retired during the summer of 2011.
   The 824 MW capacity retirement in summer 2012 represents the projected retirement date for Dan River Steam Station units 1-3 (276 MW), Cliffside Steam Station units 1-4 (198 MW), and 350 MWs of old fleet CT retirements.
   The 1080 MW capacity retirement in summer 2015 represents the projected retirement date for Lee Steam Station (370 MW), Buck Steam Station units 5 and 6 (256 MW) and Riverbend Steam Station units 4-7 (454 MW).
   The NRC has issued renewed energy facility operating licenses for all Duke Energy Carolinas' nuclear facilities.
   The Hydro facilities for which Duke has submitted an application to FERC for licence renewal are assumed to continue operation through the planning horizon.
   All retirement dates are subject to review on an ongoing basis.

9. Cumulative Purchase Contracts have several components:

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

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

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

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

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

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

The charts in Chart 8.B and 8.C show the changes in Duke Energy Carolinas' capacity mix and energy mix between 2012 and 2031. The relative shares of renewables, energy efficiency, and gas all increase, while the relative share of coal decreases.

Chart 8.B

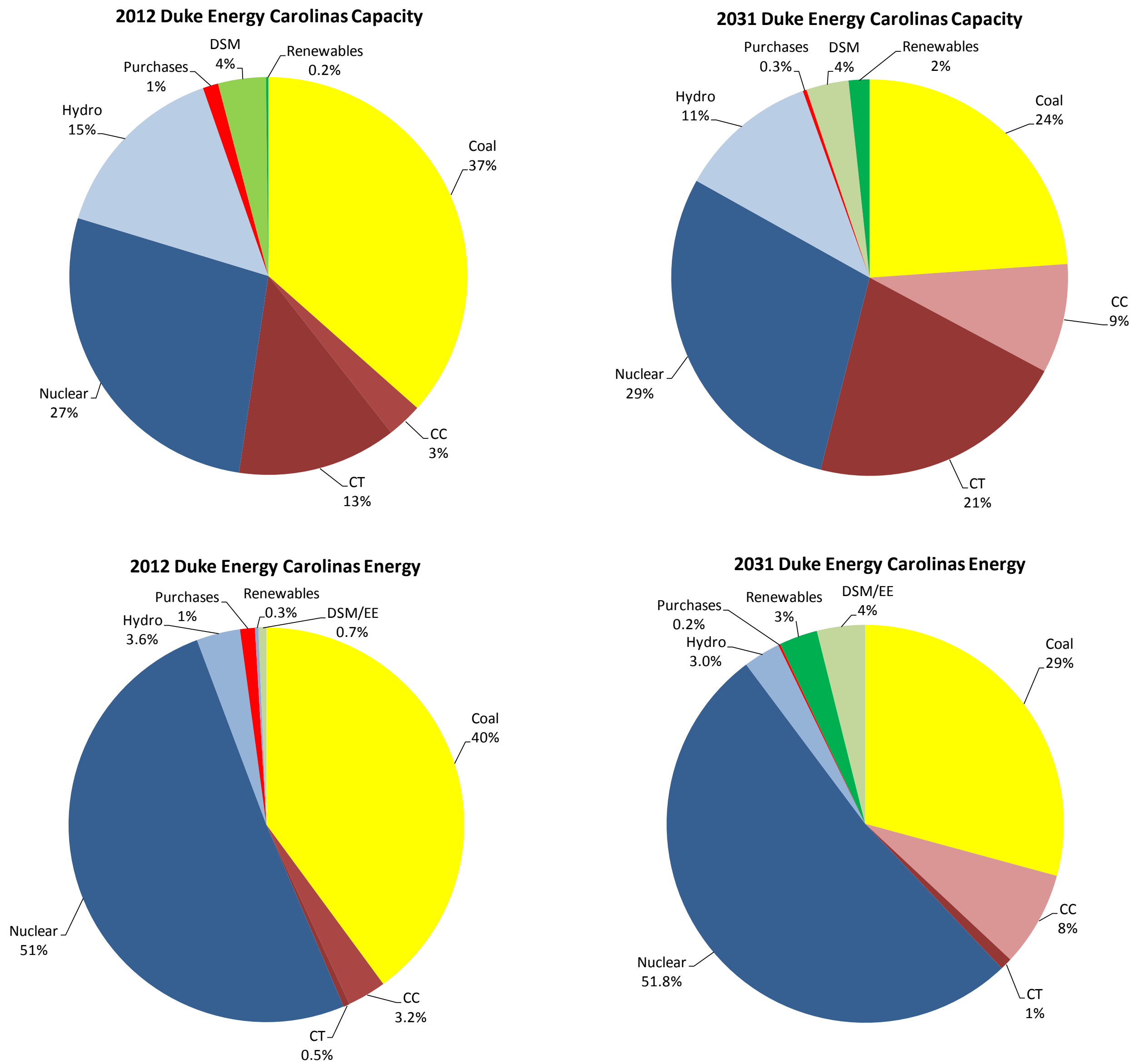
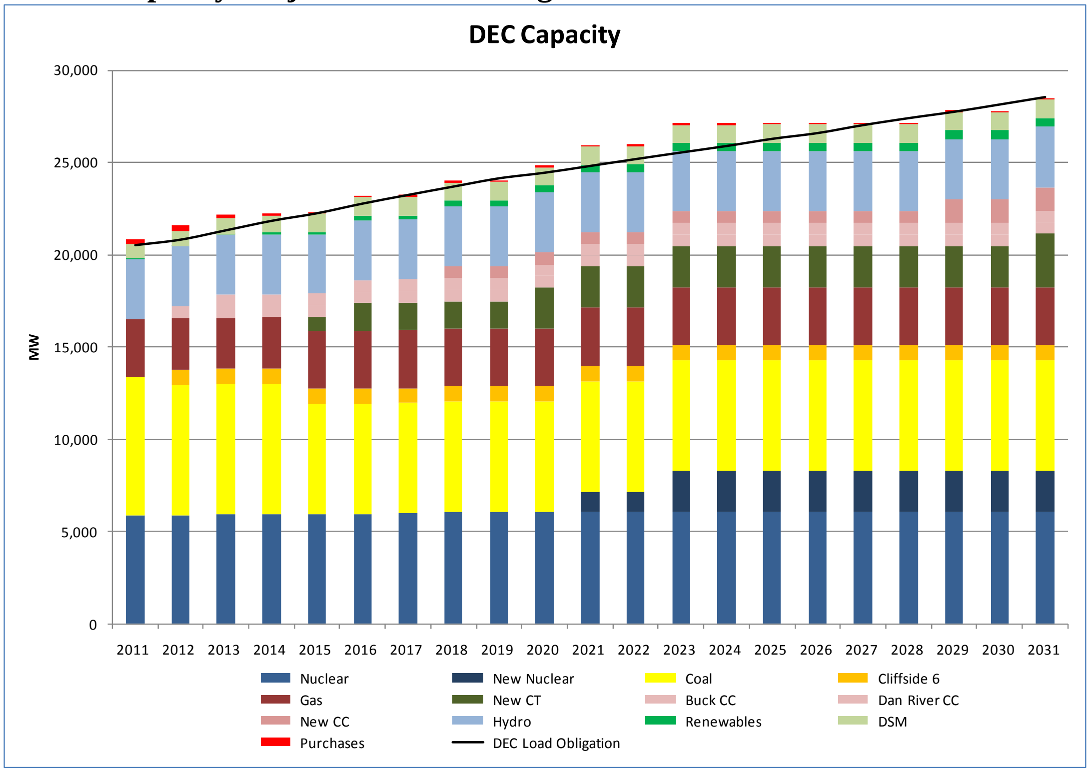


Chart 8.C
Annual Capacity Projection 2011 through 2031



Annual Energy Projection 2011 through 2031

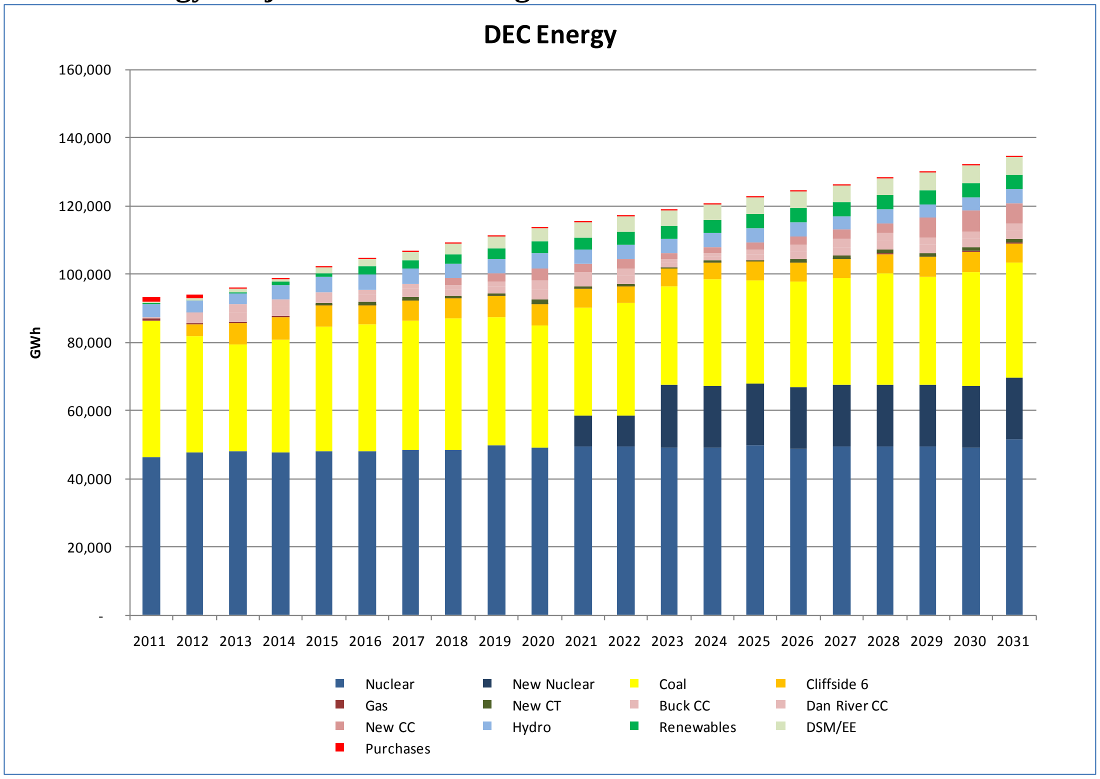


Table 8.D below represents the annual non-renewable incremental additions reflected in the LCR Table of the most robust expansion plan. The plan contains the addition of Cliffside Unit 6 in 2012, the unit retirements shown in Table 5.D and the impact of EE and DSM programs.

Table 8.D

Year	Month	Project	MW
2011	6	Jocassee Uprates	50
2011	12	Buck Combined Cycle	620
2012	6	Cliffside 6	825
2012	6	Bridgewater Hydro	8.75
2012	6	Nuclear Uprates	10
2012	12	Dan River Combined Cycle	620
2013	6	Nuclear Uprates	45
2014	6	Nuclear Uprates	18
2015	6	New CT	740
2016	6	New CT	740
2017	6	Nuclear Uprates	21
2018	6	New CC	650
2018	6	Nuclear Uprates	81
2019	6	Nuclear Uprates	30
2020	6	New CT	740
2021	6	New Nuclear	1117
2023	6	New Nuclear	1117
2029	6	New CC	650
2031	6	New CT	670

The details of the forecasted capacity additions, including both nameplate capacity and the expected contribution of renewable resources towards the Company's peak load needs, are summarized in Table 8.E below.

Table 8.E Expected Renewable Resource Capacity Additions

Renewables								
	MW Contribution to Summer Peak				MW Nameplate			
Year	Wind	Solar	Biomass	Total	Wind	Solar	Biomass	Total
2011	15.0	12	20	46	100	24	20	143
2012	0.0	12	29	41	0	24	29	53
2013	0.0	12	33	44	0	24	33	56
2014	15.0	12	89	116	100	24	89	213
2015	15.6	21	91	128	104	42	91	237
2016	47.8	22	179	249	318	45	179	542
2017	47.8	23	180	250	319	45	180	543
2018	49.7	24	230	304	332	49	230	610
2019	50.7	25	265	341	338	51	265	654
2020	53	28	296	376	352	56	296	703
2021	51	26	295	372	339	51	295	686
2022	55	28	344	427	367	57	344	767
2023	55	36	346	437	368	72	346	786
2024	55	36	347	439	369	73	347	789
2025	58	36	384	478	389	73	384	846
2026	61	41	386	488	406	81	386	874
2027	59	37	385	481	392	73	385	851
2028	59	37	388	484	393	74	388	855
2029	62	41	391	493	411	82	391	884
2030	62	41	391	493	411	82	391	884
2031	62	41	391	493	411	82	391	884

APPENDICES

APPENDIX A: QUANTITATIVE ANALYSIS

This appendix provides an overview of the Company's 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, lower demand response, and renewable compliance assumptions, results in significant resource needs to meet energy and peak demands, based on the following assumptions:

- 1.8% average summer peak system demand growth over the next 20 years without impacts of new energy efficiency programs
- Generation retirements of approximately 350 MW of old fleet combustion turbines by 2012
- Generation retirements of approximately 1,040 MW of older coal units associated with the addition of Cliffside Unit 6.
- Generation retirements of approximately 630 MW of remaining coal units without scrubbers by 2015
- 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 EE, DSM and supply-side options to meet customer energy and capacity needs. The Company develops DSM/EE options for consideration within the IRP 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). 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.

The Company compared capacity options 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:

- Baseload – 800 MW Supercritical Pulverized Coal
- Baseload – 630 MW Integrated Gasification Combined Cycle (IGCC)
- Baseload – 2,234 MW (2x1,117 MW) Nuclear units (AP1000)
- Peaking/Intermediate – 740 MW (4x185 MW) CT
- Peaking/Intermediate – 650 MW (460 MW Unfired + 150MW Duct Fired + 40MW Inlet Chilled) Natural Gas CC
- Renewable – Existing Unit Biomass Co-Firing
- Renewable – Wind PPA On-Shore
- Renewable – Landfill Gas PPA
- Renewable – Solar Photovoltaic PPA
- Renewable – Biomass Firing PPA
- Renewable – 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.

Energy Efficiency and Demand-Side Management

EE and DSM programs continue to be an important part of Duke Energy Carolinas' system mix. The Company considered both demand response and conservation programs in the analysis.

The Company modeled the costs and impacts from EE and DSM programs based on the data included in Duke Energy Carolinas' approved Energy Efficiency Plan settlement in NCUC Docket No. E-7, Sub 831. For the analysis, Duke Energy Carolinas assumed these costs and impacts would continue through the duration of the planning period.

The forecasted energy efficiency savings through 2012 are consistent with Duke Energy Carolinas' North Carolina Energy Efficiency Plan for 2009 through 2012. The Company assumes for purposes of the IRP that total efficiency savings will continue to grow on an annual basis through 2031, however the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan.

Develop Theoretical Portfolio Configurations

The Company conducted a screening analysis using a simulation model to identify the most attractive capacity options under the expected load profile as well as under a range of risk cases. This analysis began with a set of basic inputs which were varied 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 set of basic 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, spinning reserve (10 to 15-minute start-up)

- 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, the Company developed a variety of portfolios 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 optimal timing of CT, CC, and nuclear additions in the 2016 – 2031 timeframe.

The information as shown on the following pages outlines the planning options that the Company considered in the portfolio analysis phase. Each portfolio contains demand response and conservation identified in the base EE and DSM case and renewable portfolio standard requirements modeled after the NC REPS in NC and applied to SC. In addition, each portfolio contains the addition of Cliffside Unit 6 in 2012, Buck CC in 2012 and Dan River CC in 2013 and the unit retirements shown in Table 5 D.

The RPS assumptions are based on NC REPS in North Carolina. The assumptions for planning purposes are as follows:

<u>Overall Requirements/Timing</u>

- 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

<u>Additional Requirements</u>

- 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 out-of-state, unbundled RECs
- Solar requirement
    - 0.02% by 2010
    - 0.07% by 2012

    - 0.14% by 2015
    - 0.20% by 2018
- Hog waste requirement (NC only – using Duke Energy Carolinas' share of total North Carolina load which is approximately 42%)
    - 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 retail load and to wholesale customers who have contracted with Duke Energy Carolinas to meet their REPS requirement. The requirement that a certain percentage must come from Hog and Poultry waste was not applied to the South Carolina portion.

Conduct Portfolio Analysis

Duke Energy Carolinas tested the portfolio options 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 Company selected six main scenarios to illustrate the impacts of key risks and decisions. Three of these scenarios fall into the Reference CO_2 Case and three fall into the Clean Energy Legislation Case.

- Reference Case: Cap and trade program with CO_2 prices based on Duke Energy's 2011 fundamental prices.
- Clean Energy Legislation: In addition to evaluating potential CO_2 cap and trade options, the impact of proposed Clean Energy legislation without a price on CO_2 emissions was also evaluated. Assumptions used in this analysis include:
    - 10% of retail sales by 2015 must be clean energy, increasing to 30% by 2030.
    - Alternative Compliance Payment (ACP) of 50$/MWhr.
    - "Clean Energy" includes renewable resources, EE, nuclear, natural gas CC, or alternative compliance payment.
    - Portfolios based on this legislation include the increased EE to meet 25

percent of the total clean energy target.

The six analyzed portfolios are shown below:

Reference CO_2 Case Scenarios:

1. Natural Gas – Combustion turbine/combined cycle portfolio (CT/CC)
2. Lee Nuclear – Two Lee Nuclear unit portfolio with units on-line in 2021 and 2023 (2N 2021-2023)
3. Regional Nuclear – Co-ownership of nuclear units in the region. The portfolio consists of 215 MW of nuclear in 2018, 730 MW in 2021 and 2023, and 559 MW in 2028 (Reg Nuclear)

Clean Energy Legislation Scenarios:

4. Clean Energy CC – CC portfolio with the Clean Energy Legislation assumptions
5. Clean Energy 2N – Two Lee Nuclear unit portfolio with the Clean Energy Legislation assumptions
6. Clean Energy Regional Nuclear – Regional co-ownership of nuclear with the Clean Energy Legislation assumptions

An overview of the specifics of each portfolio is shown in Table A.1 below.

The sensitivities chosen to be performed for these scenarios were those representing the highest risks going forward.

The Company evaluated the following sensitivities in the Reference CO_2 Case scenarios:

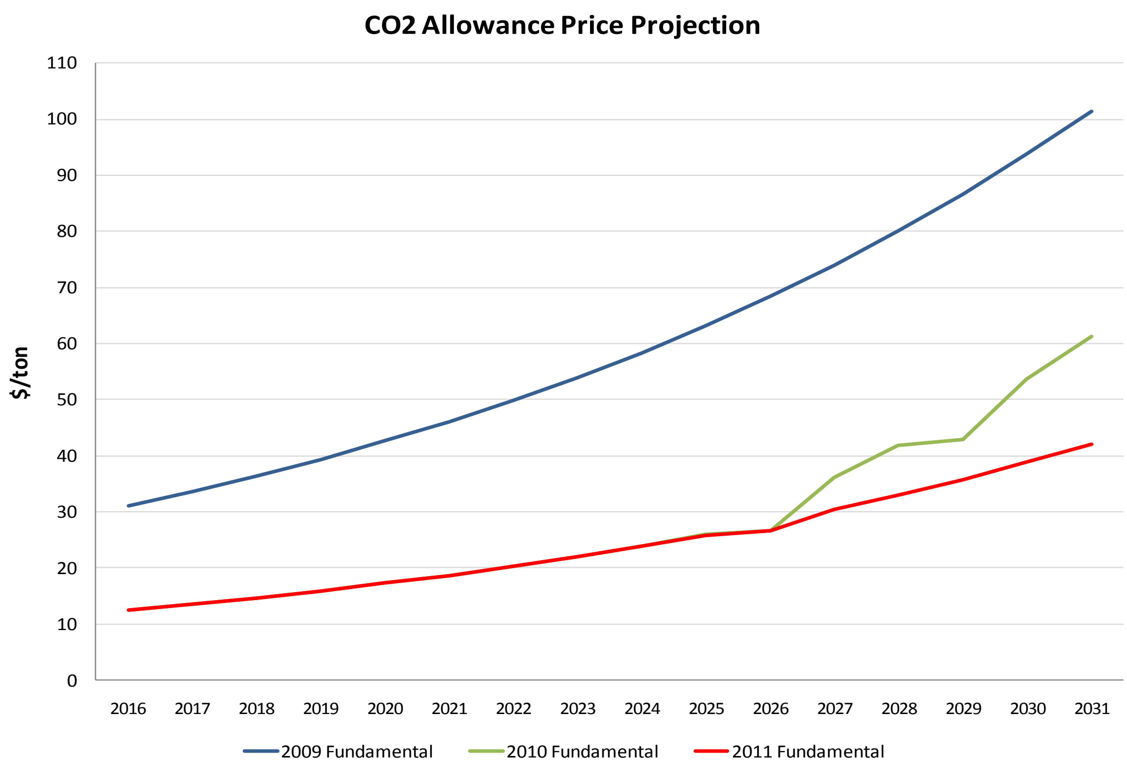
- Load forecast variations
  - Increase relative to base forecast (+15% for peak demand and +16% for energy by 2031)
  - Decrease relative to base forecast (-8% for peak demand and energy by 2031)
- Construction cost sensitivity[5]
  - Costs to construct a new nuclear plant (+20/- 10% higher than base case)
- Fuel price variability
  - Higher Fuel Prices (coal prices 25% higher, natural gas prices 25% higher)
  - Lower Fuel Prices (coal prices 40% lower, natural gas prices 40% lower)

[5] 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.

- Nuclear Financing
    - Federal loan guarantees for the Lee nuclear station
- The Carbon reference case had CO_2 emission prices ranging from $12/ton starting in 2016 to $42/ton in 2031. The Company performed sensitivities based on the 2009 and 2010 fundamental CO_2 prices.
- High Energy Efficiency – This sensitivity includes the full target impacts of the Company's 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, this increased EE impacts resulted in approximately a 13% decrease in retail sales over the planning period.

Chart A.1 shows the CO_2 prices utilized in the analysis.

Chart A.1



For the Clean Energy Legislation, the Company also performed a sensitivity by lowering the ACP to $30/MWhr and increasing the renewable energy assumptions to lower the Company's need to purchase ACPs.

An overview of the specifics of each portfolio is shown in Table A.1 below.

Table A.1 – Portfolios Evaluated

Year	Portfolios					
	CT/CC	2N 2021/2023	Regional Nuclear	Clean Energy Std - Gas	Clean Energy Std - Nuc	Clean Energy Std - Reg Nuc
2011						
2012						
2013						
2014						
2015	CT	CT	CT	CC	CT	CT
2016	CT	CT	CT	CC	CT	CT
2017						
2018	CC	CC	N	CC	CC	N
2019			CC	CC		CC
2020	CT	CT			CC	
2021		N	N		N	N
2022				CC		
2023	CC	N	N		N	N
2024				CC		
2025	CC		CT			
2026	CT			CC		CC
2027			CC			
2028	CC		N	CC		N
2029		CC				
2030	CC			CC	CT	CT
2031	CT	CT	CT	CC	CT	CT
Total CT	3,180 MW	2,890 MW	2,890 MW		2,450 MW	2,450 MW
Total CC	3,250 MW	1,300 MW	1,300 MW	6,000 MW	1,300 MW	1,300 MW
Total Nuclear		2,234 MW	2,234 MW		2,234 MW	2,234 MW
Total Nuclear Uprate	204 MW	204 MW	204 MW	204 MW	204 MW	204 MW
Total Retire	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW

Quantitative Analysis Results

The quantitative analysis focused on critical variables that impact the need for and timing of new nuclear generation. Three potential resource planning strategies were tested under base assumption and variations in CO_2 price, fuel costs, load/energy efficiency, and nuclear capital costs. These three potential resource planning strategies are:

- No new nuclear capacity (the CT/CC portfolio)

- Full ownership of new nuclear capacity (the 2 Nuclear Units portfolio)
- Regional co-ownership of new nuclear capacity (the Regional Nuclear portfolio)

For the base case and sensitivities, the Company calculated the PVRR for each portfolio. The revenue requirement calculation estimates the costs to customers for the Company to recover system production costs and new capital incurred. Duke Energy Carolinas used a 50-year analysis time frame to fully capture the long-term impact of nuclear generation added late in the 20 year planning horizon. Table A2 below represents a comparison of the Natural Gas (CT/CC) portfolio with a full ownership nuclear portfolio (1st unit in 2021 & 2nd unit in 2023) and the regional nuclear portfolio over a range of sensitivities. The green block represents the lowest PVRRs between the Natural Gas and the two nuclear portfolios. The value contained within the block is the PVRR savings in $billions between the cases.

<u>Table A.2</u>

Comparison of Nuclear Portfolios to the CT/CC Portfolio

(Cost are represented in $billions)

	Reference Case	**CO2 Price Sensitivity**		**Fuel Sensitivity**	
Portfolio		2009 Fundamental	2010 Fundamental	High Fuel Cost	Low Fuel Cost
2 Nuclear Units (2021-2023)	(0.6)	(5.9)	(2.0)	(2.8)	
Regional Nuclear	(1.1)	(6.1)	(2.4)	(3.2)	
Natural Gas					(3.0) 2N / (2.4) Reg

	Load Sensitivity			**Nuclear Capital Cost Sensitivity**	
	High Load	Low Load	High DSM	20% Increase	10% Decrease
2 Nuclear Units (2021-2023)	(1.0)	(0.6)	(0.4)		(1.8)
Regional Nuclear	(1.3)	(0.9)	(0.7)		(2.2)
Natural Gas				(1.8) 2N / (1.2) Reg	

	Nuclear Financing
Portfolio	FLG
2 Nuclear Units (2021-2023)	(1.0)
Regional Nuclear	(1.3)
Natural Gas	

	Clean Energy Bill	
Portfolio	$50 ACP	$30 ACP
2 Nuclear Units (2021-2023)	(2.6)	(1.2)
Regional Nuclear	(2.9)	(1.6)
Natural Gas		

Based on the quantitative analysis, the optimal plan includes two new nuclear units in the 2020 timeframe. The nuclear portfolios resulted in a lower cost to customers in every case with the exception of increased nuclear capital cost and lower fuel cost. In a Clean Energy Standard regulatory construct, the advantages of adding additional nuclear are greater than in a CO_2 Cap and Trade construct.

The Company's proposed portfolio including full ownership of two nuclear units in 2021 and 2023 continues to be cost effective, but the Company recognizes the potential benefits to customers of securing new nuclear generation in smaller capacity increments through regional nuclear development. The analysis indicates that the regional nuclear portfolio is lower cost to customers in the base case and most scenarios, but the full nuclear portfolio was chosen for the 2011 IRP preferred plan because there are no firm commitments in place at this time for the regional nuclear portfolio. Regional nuclear is where two or more partners plan collaboratively to stage multiple nuclear stations over a period of years and each partner would own a portion of each station. Several advantages to a regional nuclear approach are:

- Load Growth: Smaller blocks of base load generation brought on-line over a period of years would more closely match projected load growth.
- Financial: The substantial capital cost would be phased in over a longer period of time and would spread the risk if there were cost increases.
- Regulatory Uncertainty: The optimal amount and timing of additional nuclear generation will depend on the outcome of final legislation. Using a regional approach would allow utilities to better optimize their portfolios as legislation or regulation change over time.

Duke Energy Carolinas strongly supports this concept and continues to explore regional nuclear opportunities. The Company will continue to assess opportunities to benefit from economies of scale and risk reduction in new resource decisions by considering the prospects for joint ownership and/or sales agreements for new nuclear generation resources. Recent efforts in support of regional nuclear include:

- In February 2011, JEA (formerly Jacksonville Electric Authority), located in Jacksonville, Florida, signed an option to potentially purchase up to 20% of Lee Nuclear Station.

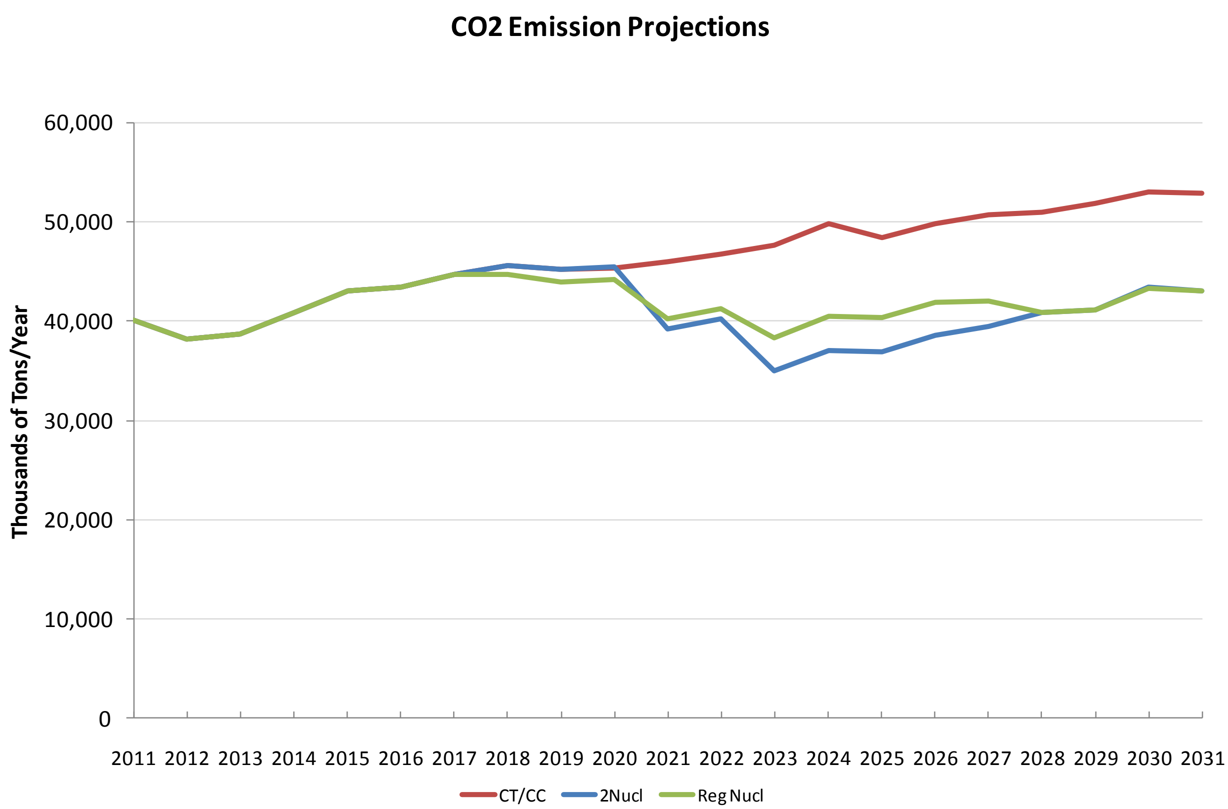
- In July 2011, the Company signed a letter of intent with Santee Cooper to perform due diligence and potentially acquire an option for a minority interest (5 to 10 percent of the capacity of the two units) in Santee Cooper's 45 percent ownership of the planned new nuclear reactors at V.C. Summer Nuclear Generating Station in South Carolina. The new units are scheduled to be online between 2016 and

2019.

Quantitative Analysis Summary

One of the major benefits 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, 2 Nuclear, and Regional Nuclear scenarios are shown in Chart A.4 below. A review of these projections illustrates that for the Company to achieve material system reductions in CO_2 emissions, it must add new nuclear generation to the future resource portfolio.

Chart A.3



The biggest risks to the proposed nuclear portfolios are the time required to license and construct a nuclear unit, uncertainty regarding GHG regulation/legislation, potential for lower demand than currently estimated, capital cost to build, and the ability to secure favorable financing. However, in a carbon constrained future, new nuclear generation must be in the generation mix to reduce the Company's carbon footprint.

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 2020 timeframe. The Company's analysis re-affirms the advantages of favorable financing and co-ownership in future nuclear generation. 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 planning horizon. Conclusions based on these analyses are:

- The new levels of EE and DSM are cost-effective for customers.
    - The screening analysis shows that portfolios with the new EE and DSM were lower cost than those without and EE and DSM.
    - The high EE sensitivity assumes 100% participation of cost effective EE programs identified in the market potential study. The high EE sensitivity is cost effective if there is an equal participation between residential and non-residential customers. If a significant number of non-residential customers opt out, then the high EE case may no longer be cost effective.
- Significant renewable resources will be needed to meet the new NC REPS (and potentially a federal standard).
- There is a capacity need in 2015 to 2020 timeframe to maintain the 17% reserve margin.
- The analysis demonstrates that the nuclear option is an attractive option for the Company's customers.
    - Continuing to preserve the option to secure new nuclear generation is prudent under the circumstances.
    - 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:

- 987 MW equivalent of incremental capacity under the new save-a-watt DSM programs
- 727 MW of new EE (reduction to system peak load)

- 2,234 MW of new nuclear capacity
- 1,300 MW of new CC capacity
- 2,890 MW of new CT capacity
- 204 MW of nuclear uprates
- 484 MW of renewables (858 MWs nameplate)

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

APPENDIX B

Duke Energy Carolinas
Spring 2011 Forecast

Sales

Rates Billed

Peaks

2011-2026

August 17, 2011

Table of Contents

Executive Summary

Regular Sales and System Peak Summer (2010 Forecast vs. 2011 Forecast)

Regular sales include total Retail and Full/Partial Requirements Wholesale sales. The system peak summer demand includes all MW demands associated with the IRP loads. The table below shows values after the effects of utility sponsored energy efficiency have been reflected.

Growth Statistics from 2011 to 2012				
	Forecasted 2011	Forecasted 2012	Growth	
Item	Amount	Amount	Amount	%
Regular Sales	81,008 GWH	82,273 GWH	1,266 GWH	1.6%
System Peak Summer	17,557 MW	17,812 MW	255 MW	1.5%

Regular Sales Outlook for the Forecast Horizon (2010 – 2026)

Total Regular sales for the Spring 2011 Forecast are projected to grow at an average annual rate of 1.5% from 2010 through 2026, the same rate as the Fall 2010 Forecast. The Spring 2011 Forecast for Residential and Commercial is higher in the short and mid-term due to higher economic growth and a smaller reduction in the expected impacts of CFL's. In the long-run, however, the Residential and Commercial forecasts are slightly lower due to higher energy efficiency impacts The Industrial Forecast is higher throughout due to stronger economic projections in industries such autos and steel, and a surprisingly improved textile outlook. Adjustments were made to the energy forecasts for the Spring 2011 Forecast and the Fall 2010 Forecast to account for utility sponsored efficiency programs. The expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007 was reflected differently in the Spring 2011 Forecast. Its impacts were reflected directly in the residential model rather than an ex-post adjustment. Additional adjustments to the Spring 2011 Forecast include sales additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) beginning in 2011.

The Full/Partial Requirements Wholesale class forecast will increase due to new sales contracts with Central Electric Power Cooperative, Inc. (CEPCI) starting in 2013.

Comparison of Regular Sales Growth Statistics Spring 2011 Forecast vs. Fall 2010 Forecast					
	Spring 2011 Forecast Annual Growth (2010-2026)		Fall 2010 Forecast Annual Growth (2010-2026)		Average Annual Difference [1]
Item	**Amount**	**%**	**Amount**	**%**	
Regular Sales:					
Residential	272 GWH	0.9%	289 GWH	0.9%	-16 GWH
Commercial	569 GWH	1.8%	595 GWH	1.8%	-26 GWH
Industrial (total)	158 GWH	0.7%	96 GWH	0.5%	62 GWH
Textile	-35 GWH	-0.9%	-64 GWH	-1.8%	29 GWH
Other Industrial	193 GWH	1.1%	160 GWH	0.9%	33 GWH
Other [2]	5 GWH	1.5%	5 GWH	1.6%	0 GWH
Full/Partial Wholesale [3]	377 GWH	5.0%	390 GWH	5.1%	-13 GWH
Total Regular	1,381 GWH	1.5%	1,375 GWH	1.5%	6 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] *For List of Full/Partial Wholesale customers see page 6. .*

System Peak Outlook for the Forecast Horizon (2010 – 2026)

System peak demands are forecasted on a summer and winter basis. Additional adjustments have been made to the Spring 2011 Forecast for the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) and utility sponsored enery efficiency programs. The system peak summer demand on the Duke Energy Carolinas is expected to grow at an average annual rate of 1.8% from 2010 through 2026. The system peak winter demand is expected to grow at an average annual rate of 1.7% from 2010 through 2026.

Comparison of System Peak Demand Growth Statistics Spring 2011 Forecast vs. Fall 2010 Forecast					
	Spring 2011 Forecast Annual Growth (2010-2026)		Fall 2010 Forecast Annual Growth (2010-2026)		Average Annual Difference [1]
Item	**Amount**	**%**	**Amount**	**%**	
System Peaks					
Summer	353 MW	1.8%	333 MW	1.7%	19 MW
Winter	316 MW	1.7%	296 MW	1.6%	20 MW

(Load Forecast pg 2)

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 1.3% annually over the forecast horizon.

(Load Forecast pg 3)

General forecasting methodology for Duke Energy Carolinas energy and demand forecasts for Spring 2010

Duke Energy Carolinas' Spring 2011 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 2011 – 2026 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

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 projections of regional economic activity, demographic trends and expected long-term weather. The economic projections used in the Spring 2011 forecasts are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the Duke Carolinas service area region. These economic forecasts represent long-term projections of numerous economic concepts including the following:

- Total real gross regional product (GRP)
- Non-manufacturing real GRP
- Non-manufacturing employment
- Manufacturing real GRP industry group, e.g., textiles
- Manufacturing Employment 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 2011 forecasts, a 10 year simple average of CDD and HDD from 2001-2010 was used.

Other factors influencing the forecasts are identified and quantified such as changes in wholesale power contracts and housing trends, which reflects the Energy Information Administration's outlook for appliance saturations and efficiency trends.

The price of electricity is also an important input to the energy and peak models. The projected price of electricity is developed by the company's Financial Model group, and incorporates expected future costs of captial additions, fuel price increases, as well as enviromental costs, such as tighter Carbon standards.

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 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 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 14 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

General forecasting methodology (continued)

Wholesale:
Duke Energy Carolnas serves the follwing wholesale customers on a full or partial basis:

Concord, Prosperity, Dallas, Lockhart, Forest City, Greenwood, Kings Mountain, Highlands, Due West, Western Carolina, Blue Ridge EMC, Piedmont EMC, New River, Rutherford EMC, Central, and NCEMC Fixed Load Shape.

The larger wholesale entities, Blue Ridge, Rutherford, and Piedmont, are forecasted by econometric models. The smaller whoelsale customers, however, are projected by using an assumed growth rate, comparable to Duke Carolinas Retail growth.

Peaks:
Adjustments were made to the energy and peak projections for the Spring 2011 Forecast to reflect additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011. The expected ban on incandescent lighting mandated by the Energy Independence and Security Act of 2007 is reflected in the residential sales model by adjusting the appliance efficiency variable.

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.

(Load Forecast Pg 6)

Billed Sales and Other Energy Requirements

(Load Forecast Pg 7)

Regular Sales, which includes billed sales to Retail and Full/Partial Requirements Wholesale classes, are expected to grow at 1381 GWH per year or 1.5% over the forecast horizon. Retail sales include GWH sales billed to the Residential, Commercial, Industrial, Street and Public Lighting, and Traffic Signal Service classes. Wholesale sales are to resale customers that Duke provides either full or partial service.

Adjustments were made to the energy and peak projections for the Spring 2011 Forecast to reflect additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011. The expected ban on incandescent lighting mandated by the Energy Independence and Security Act of 2007 is reflected in the residential sales model by adjusting the appliance efficiency variable.

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 1.4% over the forecast horizon on a temperature corrected basis..

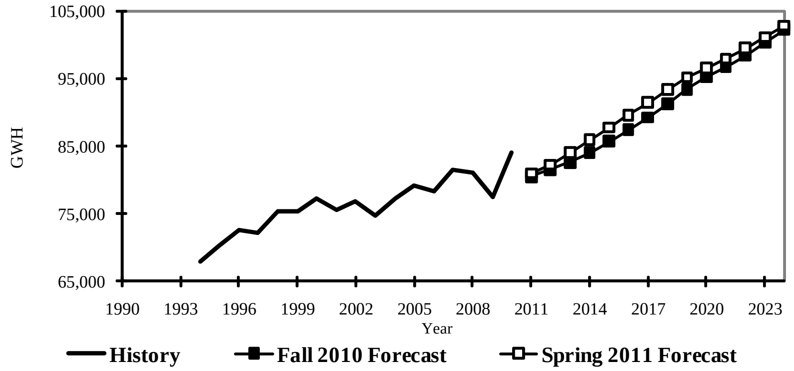
• The **Commercial** class is projected to be the fastest growing retail class, with billed sales growing at 1.8% per year over the next fifteen years. The three largest sectors in the Commercial Class are Offices, which includes banking, Retail and Education.

• The **Industrial** class rebounded strongly in 2010 after struggling for several years. The long term structural decline that has occurred in the Textile industry is expected to moderate significantly in the forecast horizon, with an overall projected decline of 0.9%. In the Other Industrial sector, several industries such as Autos, Rubber & Plastics and Primary Metals, are projected to show strong growth. Overall, Other Industrial sales are expected to grow 1.1% over the forecast horizon.

• The **Full/Partial Requirements Wholesale** class is expected to grow at 5.0% annually over the forecast horizon, primarily due to the forecasted supplemental sales to specified EMCs in North Carolina and sales to CEPCI in South Carolina.

(Load Forecast Pg 8)

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



HISTORY

Year	Actual GWH	Growth GWH	Growth %
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
2009	77,528	-3,538	-4.4
2010	84,088	6,560	8.5

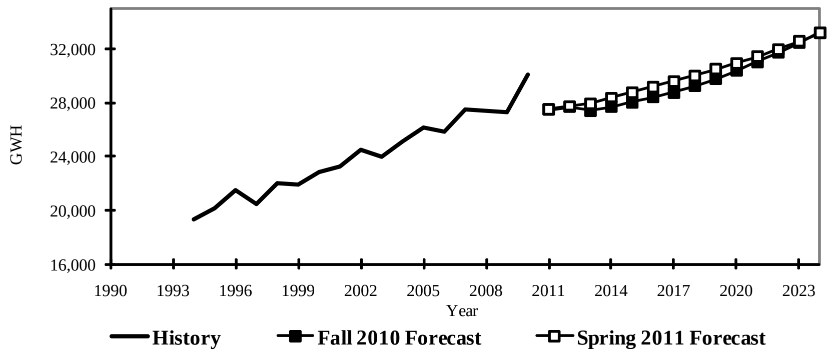
AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2005 to 2010)	992	1.2
History (1995 to 2010)	918	1.2
Spring 2011 Forecast (2010 to 2026)	1381	1.5
Fall 2010 Forecast (2010 to 2026)	1375	1.5

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	GWH	Growth GWH	Growth %	Fall 2010 GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	81,008	-3,081	-3.7	80,519	489	0.6	-3,570
2012	82,273	1,266	1.6	81,543	730	0.9	1,025
2013	84,039	1,766	2.1	82,577	1,462	1.8	1,034
2014	85,930	1,891	2.2	84,041	1,890	2.2	1,463
2015	87,752	1,821	2.1	85,715	2,037	2.4	1,674
2016	89,570	1,819	2.1	87,393	2,178	2.5	1,678
2017	91,427	1,857	2.1	89,235	2,192	2.5	1,843
2018	93,364	1,937	2.1	91,248	2,115	2.3	2,013
2019	95,146	1,782	1.9	93,415	1,731	1.9	2,167
2020	96,546	1,399	1.5	95,166	1,380	1.4	1,751
2021	97,950	1,405	1.5	96,687	1,263	1.3	1,521
2022	99,479	1,529	1.6	98,432	1,047	1.1	1,745
2023	101,104	1,625	1.6	100,294	810	0.8	1,862
2024	102,775	1,670	1.7	102,224	551	0.5	1,930
2025	104,454	1,679	1.6	104,107	347	0.3	1,883
2026	106,189	1,734	1.7	106,094	94	0.1	1,987

Residential Billed Sales



HISTORY

Year	Actual GWH	Growth GWH	Growth %
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
2009	27,273	-62	-0.2
2010	30,049	2,777	10.2

AVERAGE ANNUAL GROWTH

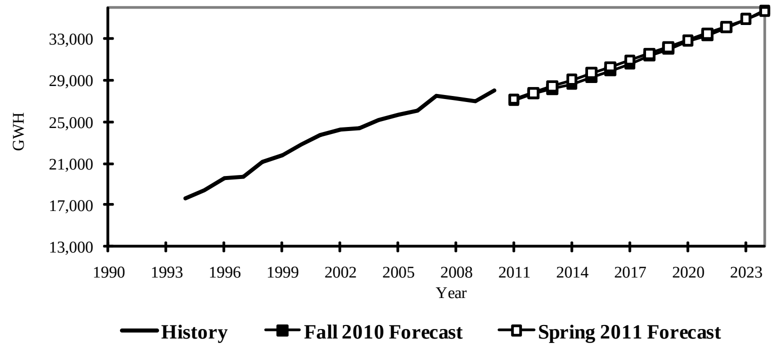
	GWH Per Year	% Per Year
History (2005 to 2010)	788	2.9
History (1995 to 2010)	662	2.7
Spring 2011 Forecast (2010 to 2026)	272	0.9
Fall 2010 Forecast (2010 to 2026)	289	0.9

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	Spring 2011 GWH	Growth GWH	Growth %	Fall 2010 GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	27,517	-2,532	-8.4	27,464	53	0.2	-2,585
2012	27,749	232	0.8	27,656	93	0.3	192
2013	27,914	165	0.6	27,400	514	1.9	-255
2014	28,350	436	1.6	27,663	687	2.5	262
2015	28,760	410	1.4	28,036	724	2.6	373
2016	29,154	394	1.4	28,367	787	2.8	331
2017	29,554	400	1.4	28,743	811	2.8	376
2018	29,995	441	1.5	29,201	794	2.7	458
2019	30,454	459	1.5	29,732	722	2.4	531
2020	30,926	472	1.5	30,315	612	2.0	582
2021	31,387	461	1.5	31,008	379	1.2	693
2022	31,946	559	1.8	31,698	248	0.8	691
2023	32,535	589	1.8	32,434	101	0.3	736
2024	33,154	619	1.9	33,204	-50	-0.1	770
2025	33,774	620	1.9	33,896	-122	-0.4	692
2026	34,408	634	1.9	34,668	-260	-0.7	772

(Load Forecast Pg 10)

Commercial Billed Sales



HISTORY

Year	Actual GWH	Growth GWH	Growth %
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
2009	26,977	-311	-1.1
2010	27,968	991	3.7

AVERAGE ANNUAL GROWTH

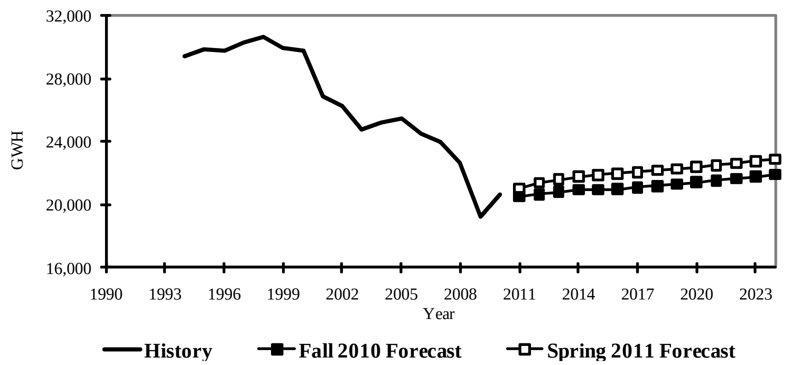
	GWH Per Year	% Per Year
History (2005 to 2010)	458	1.7
History (1995 to 2010)	634	2.8
Spring 2011 Forecast (2010 to 2026)	569	1.8
Fall 2010 Forecast (2010 to 2026)	595	1.8

SPRING 2011 FORECAST / **Fall 2010 FORECAST**

Year	GWH	Growth GWH	Growth %	Fall 2010 GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	27,148	-820	-2.9	27,076	72	0.3	-892
2012	27,759	611	2.3	27,688	72	0.3	612
2013	28,399	640	2.3	28,146	253	0.9	458
2014	29,031	631	2.2	28,588	443	1.5	442
2015	29,658	627	2.2	29,229	429	1.5	641
2016	30,281	623	2.1	29,903	378	1.3	674
2017	30,907	626	2.1	30,571	336	1.1	668
2018	31,537	630	2.0	31,301	236	0.8	730
2019	32,173	636	2.0	32,020	153	0.5	719
2020	32,815	642	2.0	32,760	54	0.2	741
2021	33,468	653	2.0	33,295	173	0.5	535
2022	34,129	662	2.0	34,040	89	0.3	745
2023	34,847	718	2.1	34,862	-15	0.0	822
2024	35,577	729	2.1	35,710	-133	-0.4	847
2025	36,319	742	2.1	36,598	-279	-0.8	888
2026	37,074	756	2.1	37,494	-420	-1.1	896

(Load Forecast Pg 11)

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



HISTORY | **AVERAGE ANNUAL GROWTH**

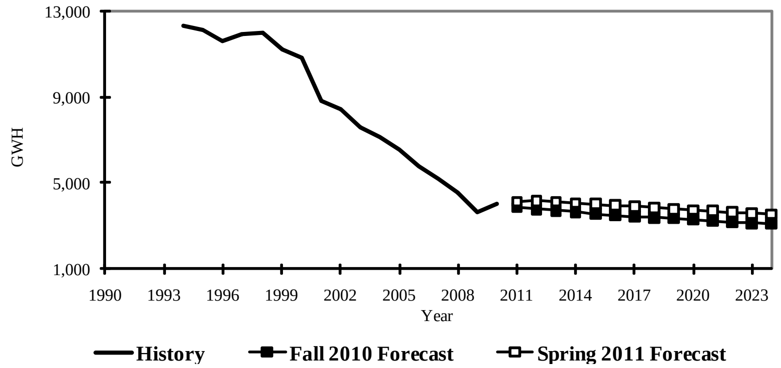
Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
2001	26,902	-2,869	-9.6			
2002	26,259	-643	-2.4			
2003	24,764	-1,496	-5.7			
2004	25,209	445	1.8			
2005	25,495	286	1.1			
2006	24,535	-960	-3.8	History (2005 to 2010)	-975	-4.2
2007	23,948	-587	-2.4	History (1995 to 2010)	-618	-2.4
2008	22,634	-1,314	-5.5			
2009	19,204	-3,430	-15.2	Spring 2011 Forecast (2010 to 2026)	158	0.7
2010	20,618	1,414	7.4	Fall 2010 Forecast (2010 to 2026)	96	0.5

SPRING 2011 FORECAST | **Fall 2010 FORECAST**

Year	GWH	Growth GWH	Growth %	GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	21,026	408	2.0	20,515	511	2.5	-103
2012	21,374	348	1.7	20,664	711	3.4	149
2013	21,600	225	1.1	20,812	787	3.8	149
2014	21,770	171	0.8	20,951	819	3.9	139
2015	21,871	100	0.5	20,944	927	4.4	-7
2016	21,963	93	0.4	20,982	981	4.7	38
2017	22,059	96	0.4	21,082	977	4.6	100
2018	22,159	100	0.5	21,178	981	4.6	96
2019	22,263	104	0.5	21,294	969	4.6	116
2020	22,375	112	0.5	21,404	970	4.5	111
2021	22,493	119	0.5	21,525	969	4.5	120
2022	22,618	125	0.6	21,653	966	4.5	128
2023	22,748	130	0.6	21,777	972	4.5	124
2024	22,876	128	0.6	21,901	975	4.5	124
2025	23,001	125	0.5	22,025	976	4.4	124
2026	23,147	146	0.6	22,161	987	4.5	136

(Load Forecast Pg 12)

Textile Billed Sales



HISTORY

Year	Actual GWH	Growth GWH	Growth %
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
2009	3,616	-908	-20.1
2010	4,003	387	10.7

AVERAGE ANNUAL GROWTH

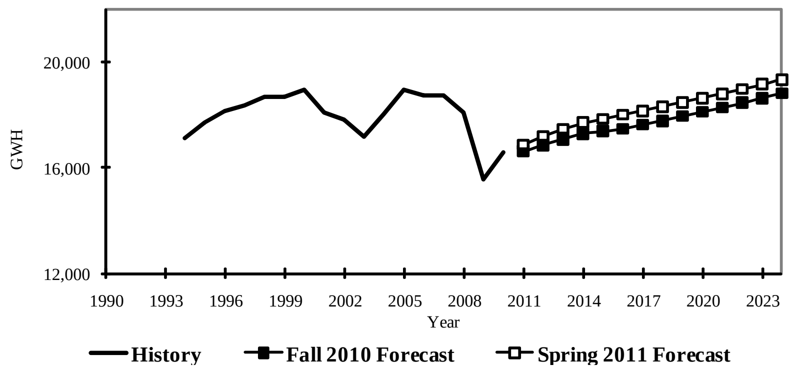
	GWH Per Year	% Per Year
History (2005 to 2010)	-512	-9.4
History (1995 to 2010)	-543	-7.1
Spring 2011 Forecast (2010 to 2026)	-35	-0.9
Fall 2010 Forecast (2010 to 2026)	-64	-1.8

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	GWH	Growth GWH	Growth %	Fall 2010 GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	4,134	131	3.3	3,872	261	6.8	-130
2012	4,159	25	0.6	3,788	371	9.8	-84
2013	4,125	-33	-0.8	3,723	403	10.8	-66
2014	4,068	-57	-1.4	3,656	412	11.3	-66
2015	4,011	-57	-1.4	3,560	451	12.7	-96
2016	3,953	-57	-1.4	3,499	454	13.0	-60
2017	3,900	-54	-1.4	3,445	455	13.2	-55
2018	3,845	-54	-1.4	3,390	455	13.4	-55
2019	3,790	-55	-1.4	3,339	451	13.5	-51
2020	3,739	-51	-1.3	3,286	453	13.8	-53
2021	3,689	-51	-1.4	3,235	453	14.0	-51
2022	3,638	-51	-1.4	3,184	454	14.2	-51
2023	3,588	-50	-1.4	3,131	457	14.6	-53
2024	3,539	-49	-1.4	3,078	460	15.0	-52
2025	3,491	-48	-1.4	3,028	463	15.3	-50
2026	3,445	-45	-1.3	2,979	466	15.7	-49

(Load Forecast Pg 13)

Other Industrial Billed Sales



HISTORY **AVERAGE ANNUAL GROWTH**

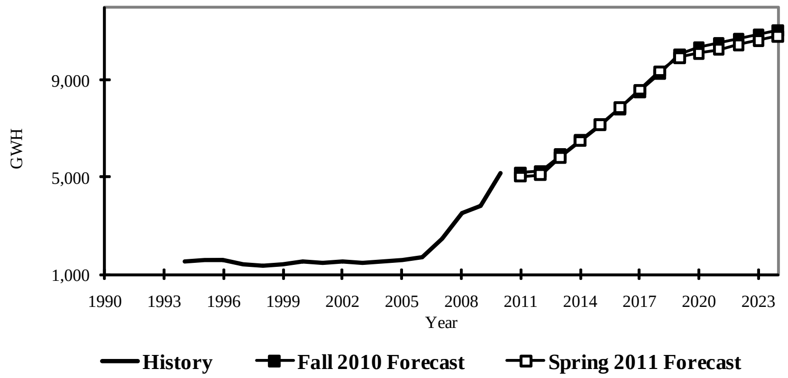
Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
2001	18,077	-880	-4.6			
2002	17,816	-261	-1.4			
2003	17,202	-614	-3.4			
2004	18,063	861	5.0			
2005	18,934	872	4.8			
2006	18,744	-191	-1.0	History (2005 to 2010)	-464	-2.6
2007	18,724	-20	-0.1	History (1995 to 2010)	-75	-0.4
2008	18,110	-614	-3.3			
2009	15,588	-2,522	-13.9	Spring 2011 Forecast (2010 to 2026)	193	1.1
2010	16,616	1,028	6.6	Fall 2010 Forecast (2010 to 2026)	160	0.9

SPRING 2011 FORECAST **Fall 2010 FORECAST**

Year	GWH	Growth GWH	Growth %	GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	16,893	277	1.7	16,643	250	1.5	27
2012	17,216	323	1.9	16,876	340	2.0	233
2013	17,474	259	1.5	17,090	385	2.3	214
2014	17,702	228	1.3	17,295	407	2.4	205
2015	17,860	158	0.9	17,384	476	2.7	89
2016	18,010	150	0.8	17,483	527	3.0	99
2017	18,159	150	0.8	17,637	522	3.0	154
2018	18,314	154	0.8	17,788	526	3.0	151
2019	18,473	159	0.9	17,955	518	2.9	167
2020	18,635	162	0.9	18,118	517	2.9	163
2021	18,805	169	0.9	18,289	515	2.8	171
2022	18,981	176	0.9	18,469	512	2.8	179
2023	19,160	180	0.9	18,646	515	2.8	177
2024	19,337	177	0.9	18,822	515	2.7	177
2025	19,510	173	0.9	18,997	514	2.7	174
2026	19,702	192	1.0	19,182	520	2.7	185

(Load Forecast Pg 14)

Full / Partial Requirements Wholesale Billed Sales [1]



HISTORY / AVERAGE ANNUAL GROWTH

Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
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	History (2005 to 2010)	717	26.7
2007	2,454	760	44.8	History (1995 to 2010)	238	8.1
2008	3,525	1,072	43.7			
2009	3,788	262	7.4	Spring 2011 Forecast (2010 to 2026)	377	5.0
2010	5,166	1,379	36.4	Fall 2010 Forecast (2010 to 2026)	390	5.1

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	GWH	Growth GWH	Growth %	Fall 2010 GWH	SPRING 2011 vs. FALL 2010 GWH	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	5,027	-139	-2.7	5,172	-145	-2.8	6
2012	5,098	71	1.4	5,239	-141	-2.7	67
2013	5,829	731	14.3	5,917	-88	-1.5	678
2014	6,478	648	11.1	6,532	-55	-0.8	615
2015	7,157	679	10.5	7,194	-37	-0.5	662
2016	7,862	705	9.8	7,823	38	0.5	629
2017	8,592	730	9.3	8,518	74	0.9	694
2018	9,353	761	8.9	9,241	112	1.2	724
2019	9,932	579	6.2	10,037	-106	-1.1	796
2020	10,101	169	1.7	10,349	-248	-2.4	311
2021	10,268	168	1.7	10,517	-249	-2.4	168
2022	10,446	177	1.7	10,693	-247	-2.3	176
2023	10,628	182	1.7	10,868	-240	-2.2	175
2024	10,816	188	1.8	11,051	-235	-2.1	183
2025	11,002	186	1.7	11,224	-222	-2.0	173
2026	11,195	192	1.7	11,402	-208	-1.8	178

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

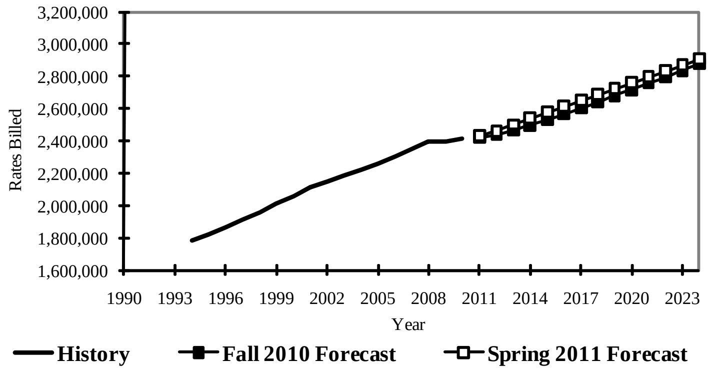
(Load Forecast Pg 15)

Number of Rates Billed

(Load Forecast Pg 16)

Total Rates Billed

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



HISTORY | **AVERAGE ANNUAL GROWTH**

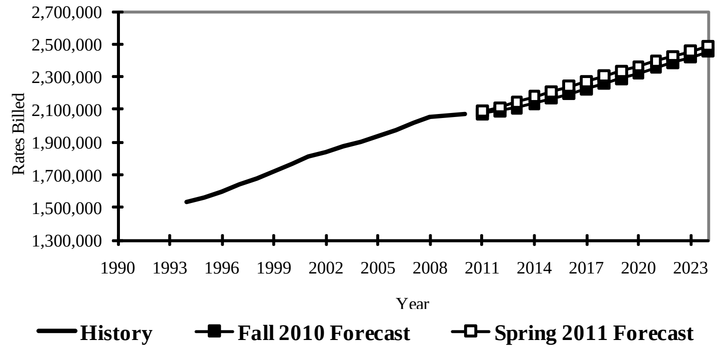
Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
2001	2,117,432	58,280	2.8			
2002	2,148,117	30,685	1.4			
2003	2,186,825	38,708	1.8			
2004	2,221,590	34,766	1.6			
2005	2,261,639	40,049	1.8			
2006	2,304,050	42,411	1.9	History (2005 to 2010)	30,289	1.3
2007	2,354,078	50,028	2.2	History (1995 to 2010)	39,573	1.9
2008	2,393,426	39,348	1.7			
2009	2,399,359	5,933	0.2	Spring 2011 Forecast (2010 to 2026)	35,490	1.3
2010	2,413,085	13,727	0.6	Fall 2010 Forecast (2010 to 2026)	34,098	1.3

SPRING 2011 FORECAST | **Fall 2010 FORECAST**

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	SPRING 2011 vs. FALL 2010 Rates Billed	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	2,432,796	19,711	0.8	2,419,493	13,303	0.5	6,408
2012	2,461,853	29,057	1.2	2,441,122	20,731	0.8	21,629
2013	2,500,751	38,899	1.6	2,467,355	33,396	1.4	26,233
2014	2,539,624	38,872	1.6	2,498,353	41,271	1.7	30,997
2015	2,577,453	37,829	1.5	2,532,562	44,891	1.8	34,210
2016	2,614,490	37,037	1.4	2,567,517	46,973	1.8	34,955
2017	2,651,397	36,907	1.4	2,605,027	46,370	1.8	37,510
2018	2,688,220	36,823	1.4	2,642,592	45,629	1.7	37,565
2019	2,724,824	36,604	1.4	2,680,067	44,757	1.7	37,475
2020	2,761,410	36,586	1.3	2,718,487	42,923	1.6	38,420
2021	2,798,003	36,593	1.3	2,757,932	40,070	1.5	39,445
2022	2,834,602	36,599	1.3	2,797,858	36,743	1.3	39,926
2023	2,871,206	36,604	1.3	2,837,010	34,196	1.2	39,151
2024	2,907,812	36,606	1.3	2,876,261	31,551	1.1	39,251
2025	2,944,418	36,606	1.3	2,917,108	27,310	0.9	40,847
2026	2,980,922	36,504	1.2	2,958,661	22,261	0.8	41,553

(Load Forecast Pg 17)

Residential Rates Billed



HISTORY — **AVERAGE ANNUAL GROWTH**

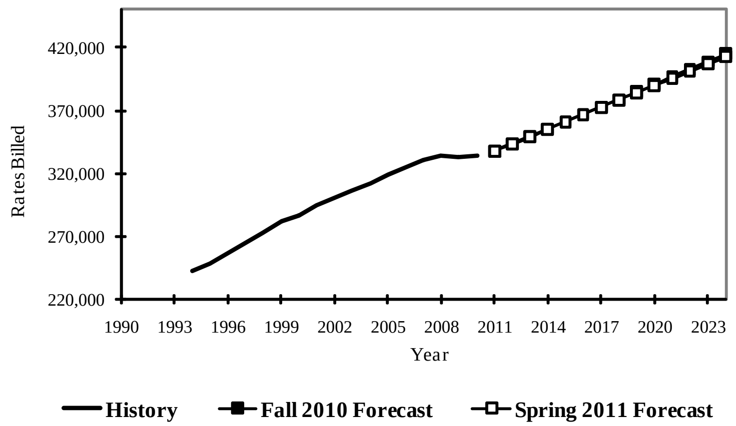
Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
2001	1,813,867	49,684	2.8			
2002	1,839,689	25,822	1.4			
2003	1,872,484	32,795	1.8			
2004	1,901,335	28,851	1.5			
2005	1,935,320	33,985	1.8			
2006	1,971,673	36,353	1.9	History (2005 to 2010)	27,311	1.4
2007	2,016,104	44,431	2.3	History (1995 to 2010)	33,990	1.9
2008	2,052,252	36,149	1.8			
2009	2,059,394	7,142	0.3	Spring 2011 Forecast (2010 to 2026)	29,890	1.3
2010	2,071,877	12,484	0.6	Fall 2010 Forecast (2010 to 2026)	28,311	1.2

SPRING 2011 FORECAST — **Fall 2010 FORECAST**

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	SPRING 2011 vs. FALL 2010 Rates Billed	%		Fall 2010 Growth Per Year
2011	2,087,805	15,928	0.8	2,074,790	13,016	0.6		2,913
2012	2,111,339	23,534	1.1	2,090,384	20,955	1.0	0.8%	15,594
2013	2,144,532	33,193	1.6	2,110,803	33,729	1.6	1.0%	20,419
2014	2,177,288	32,756	1.5	2,136,238	41,051	1.9	1.2%	25,434
2015	2,209,204	31,915	1.5	2,164,770	44,433	2.1	1.3%	28,533
2016	2,240,467	31,263	1.4	2,193,961	46,505	2.1	1.3%	29,191
2017	2,271,658	31,192	1.4	2,225,590	46,068	2.1	1.4%	31,628
2018	2,302,781	31,122	1.4	2,257,247	45,533	2.0	1.4%	31,658
2019	2,333,700	30,919	1.3	2,288,808	44,892	2.0	1.4%	31,560
2020	2,364,617	30,918	1.3	2,321,292	43,325	1.9	1.4%	32,484
2021	2,395,539	30,922	1.3	2,354,751	40,788	1.7	1.4%	33,459
2022	2,426,465	30,925	1.3	2,388,605	37,860	1.6	1.4%	33,854
2023	2,457,395	30,931	1.3	2,421,649	35,747	1.5	1.4%	33,044
2024	2,488,332	30,937	1.3	2,454,772	33,559	1.4	1.4%	33,124
2025	2,519,270	30,939	1.2	2,489,476	29,794	1.2	1.4%	34,704
2026	2,550,110	30,840	1.2	2,524,854	25,256	1.0	1.4%	35,378

(Load Forecast Pg 18)

Commercial Rates Billed

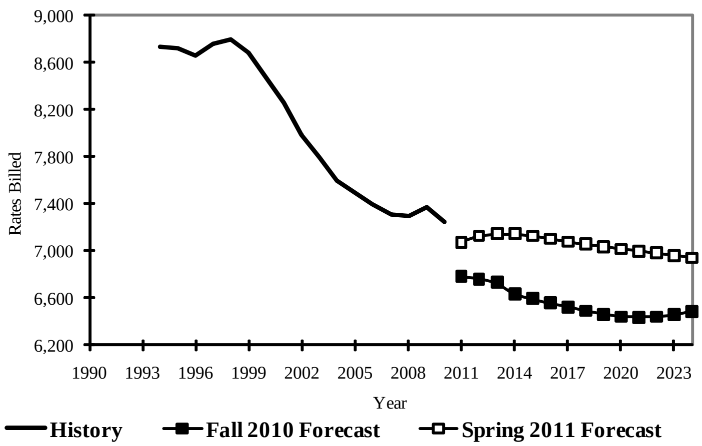


HISTORY				**AVERAGE ANNUAL GROWTH**		
Year	**Actual Rates Billed**	**Growth Rates Billed**	**%**		**Rates Billed Per Year**	**% Per Year**
2001	295,300	8,805	3.1			
2002	300,440	5,140	1.7			
2003	306,540	6,101	2.0			
2004	312,665	6,125	2.0			
2005	318,827	6,162	2.0			
2006	324,977	6,150	1.9	History (2005 to 2010)	3,027	0.9
2007	330,666	5,689	1.8	History (1995 to 2010)	5,681	2.0
2008	333,873	3,208	1.0			
2009	332,593	-1,280	-0.4	Spring 2011 Forecast (2010 to 2026)	5,622	1.5
2010	333,960	1,367	0.4	Fall 2010 Forecast (2010 to 2026)	5,831	1.6

SPRING 2011 FORECAST				**Fall 2010 FORECAST**			
					SPRING 2011 vs. FALL 2010		**Fall 2010 Growth**
Year	**Rates Billed**	**Growth Rates Billed**	**%**	**Rates Billed**	**Rates Billed**	**%**	**Per Year**
2011	337,918	3,958	1.2	337,920	-2	0.0	3,960
2012	343,384	5,466	1.6	343,977	-593	-0.2	6,057
2013	349,077	5,693	1.7	349,819	-742	-0.2	5,842
2014	355,189	6,112	1.8	355,484	-295	-0.1	5,666
2015	361,123	5,934	1.7	361,197	-73	0.0	5,713
2016	366,919	5,795	1.6	366,998	-80	0.0	5,801
2017	372,660	5,741	1.6	372,916	-256	-0.1	5,917
2018	378,382	5,722	1.5	378,856	-474	-0.1	5,941
2019	384,087	5,705	1.5	384,800	-713	-0.2	5,944
2020	389,777	5,690	1.5	390,755	-979	-0.3	5,955
2021	395,466	5,690	1.5	396,748	-1,281	-0.3	5,992
2022	401,157	5,690	1.4	402,814	-1,657	-0.4	6,066
2023	406,848	5,691	1.4	408,904	-2,057	-0.5	6,090
2024	412,539	5,692	1.4	415,002	-2,463	-0.6	6,098
2025	418,232	5,693	1.4	421,113	-2,881	-0.7	6,111
2026	423,917	5,685	1.4	427,255	-3,338	-0.8	6,142

(Load Forecast Pg 19)

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



HISTORY **AVERAGE ANNUAL GROWTH**

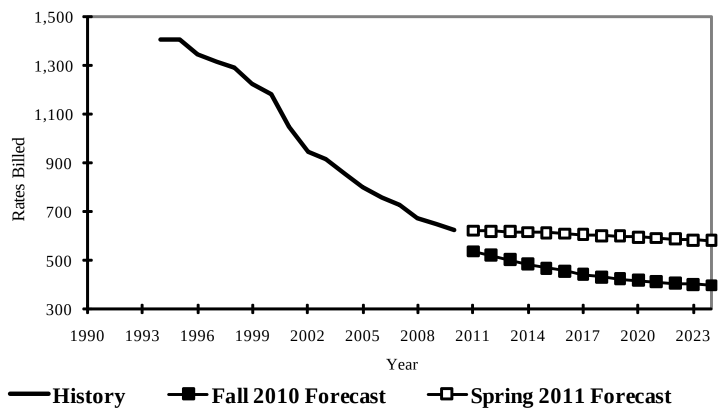
Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
2001	8,265	-210	-2.5			
2002	7,989	-276	-3.3			
2003	7,801	-188	-2.3			
2004	7,591	-210	-2.7			
2005	7,492	-99	-1.3			
2006	7,401	-91	-1.2	History (2005 to 2010)	-49	-0.7
2007	7,309	-92	-1.2	History (1995 to 2010)	-98	-1.2
2008	7,301	-8	-0.1			
2009	7,372	71	1.0	Spring 2011 Forecast (2010 to 2026)	-22	-0.3
2010	7,248	-124	-1.7	Fall 2010 Forecast (2010 to 2026)	-44	-0.6

SPRING 2011 FORECAST **Fall 2010 FORECAST**

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	SPRING 2011 vs. FALL 2010 Rates Billed	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	7,073	-175	-2.4	6,783	289	4.3	-465
2012	7,130	57	0.8	6,761	368	5.4	-22
2013	7,143	13	0.2	6,733	409	6.1	-28
2014	7,146	3	0.0	6,631	515	7.8	-102
2015	7,126	-20	-0.3	6,595	531	8.0	-36
2016	7,104	-22	-0.3	6,557	547	8.3	-38
2017	7,079	-26	-0.4	6,522	557	8.5	-36
2018	7,057	-21	-0.3	6,488	569	8.8	-34
2019	7,037	-20	-0.3	6,459	578	8.9	-29
2020	7,016	-21	-0.3	6,440	576	8.9	-19
2021	6,997	-19	-0.3	6,434	564	8.8	-6
2022	6,981	-17	-0.2	6,440	541	8.4	6
2023	6,963	-18	-0.3	6,457	506	7.8	17
2024	6,941	-22	-0.3	6,486	455	7.0	29
2025	6,915	-26	-0.4	6,519	397	6.1	33
2026	6,894	-22	-0.3	6,551	343	5.2	32

(Load Forecast Pg 20)

Textile Rates Billed



HISTORY **AVERAGE ANNUAL GROWTH**

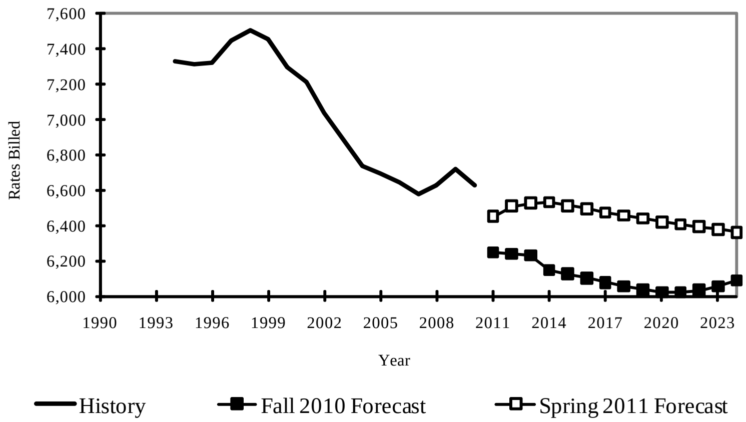
Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
2001	1,052	-129	-10.9			
2002	949	-103	-9.8			
2003	914	-35	-3.6			
2004	857	-57	-6.2			
2005	802	-56	-6.5			
2006	757	-45	-5.6	History (2005 to 2010)	-36	-4.9
2007	728	-29	-3.8	History (1995 to 2010)	-52	-5.3
2008	675	-53	-7.3			
2009	649	-26	-3.9	Spring 2011 Forecast (2010 to 2026)	-3	-0.5
2010	622	-27	-4.2	Fall 2010 Forecast (2010 to 2026)	-14	-2.9

SPRING 2011 FORECAST **Fall 2010 FORECAST**

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	SPRING 2011 vs. FALL 2010 Rates Billed	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	623	1	0.1	536	86	16.1	-86
2012	621	-2	-0.3	522	99	19.0	-15
2013	618	-2	-0.4	503	115	22.8	-18
2014	616	-2	-0.4	485	131	27.1	-19
2015	613	-3	-0.5	469	144	30.7	-16
2016	609	-4	-0.6	455	154	33.8	-14
2017	606	-3	-0.6	443	163	36.8	-12
2018	602	-3	-0.6	432	170	39.3	-11
2019	599	-4	-0.6	424	175	41.4	-9
2020	595	-3	-0.6	417	178	42.7	-7
2021	592	-3	-0.6	412	180	43.8	-5
2022	588	-4	-0.6	407	182	44.7	-5
2023	585	-4	-0.7	402	183	45.5	-5
2024	581	-4	-0.7	398	182	45.8	-3
2025	576	-5	-0.8	395	181	45.9	-3
2026	573	-3	-0.6	391	182	46.5	-4

(Load Forecast Pg 21)

Other Industrial Rates Billed



HISTORY **AVERAGE ANNUAL GROWTH**

Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
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	History (2005 to 2010)	-13	-0.2
2007	6,581	-63	-0.9	History (1995 to 2010)	-46	-0.7
2008	6,626	45	0.7			
2009	6,723	97	1.5	Spring 2011 Forecast (2010 to 2026)	-19	-0.3
2010	6,626	-97	-1.4	Fall 2010 Forecast (2010 to 2026)	-29	-0.5

SPRING 2011 FORECAST **Fall 2010 FORECAST**

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	SPRING 2011 vs. FALL 2010 Rates Billed	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	6,450	-176	-2.7	6,247	203	3.2	-379
2012	6,509	59	0.9	6,240	269	4.3	-8
2013	6,524	15	0.2	6,230	294	4.7	-10
2014	6,530	6	0.1	6,146	384	6.2	-84
2015	6,513	-17	-0.3	6,126	387	6.3	-20
2016	6,495	-18	-0.3	6,102	393	6.4	-24
2017	6,473	-22	-0.3	6,079	394	6.5	-23
2018	6,455	-18	-0.3	6,056	399	6.6	-23
2019	6,438	-17	-0.3	6,036	403	6.7	-20
2020	6,420	-18	-0.3	6,023	398	6.6	-13
2021	6,405	-15	-0.2	6,022	383	6.4	-1
2022	6,392	-13	-0.2	6,033	359	5.9	11
2023	6,378	-14	-0.2	6,055	323	5.3	22
2024	6,360	-18	-0.3	6,088	273	4.5	32
2025	6,339	-21	-0.3	6,124	216	3.5	36
2026	6,321	-18	-0.3	6,160	161	2.6	36

(Load Forecast Pg 22)

System Peaks

(Load Forecast Pg 23)

Summer Peak

The Summer peak forecast represents the maximum coincidental demand during the summer season on the Duke Energy Carolinas system. It includes all Retail classes as well as wholesale customers to whom Duke provides full or partial service. It represents the Integrated Resource Plan load that Duke is obligated to serve. It is expressed in MW at the point of generation and includes losses.

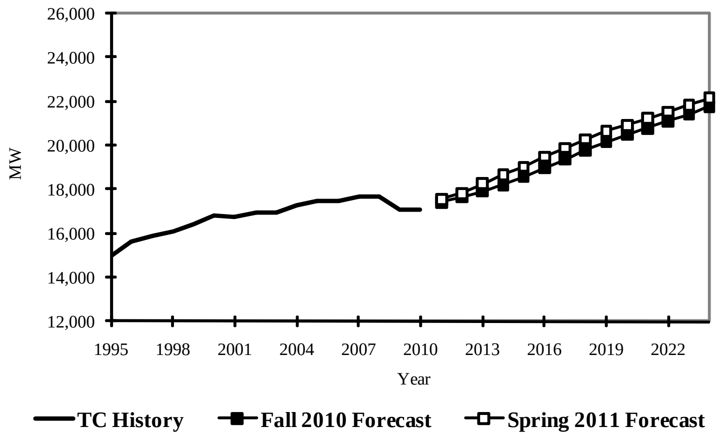
Adjustments were made to the peak forecast associated with price increases due to a Carbon Tax starting in 2015 and peak additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011. Adjustments were also made to reflect the impacts of utility sponsored energy efficiency programs.

Growth Forecasts

The new forecast projects an incremental growth of 345 MW or 1.7% per year for 2011-2026. The previous forecast growth was 334 MW or 1.7% per year for 2011-2026.

(Load Forecast Pg 24)

System Summer MW (IRP Load)



HISTORY

Year	Weather Normalized MW	Growth MW	Growth %
2001	16,748	-79	-0.5
2002	16,919	171	1.0
2003	16,915	-4	0.0
2004	17,285	370	2.2
2005	17,497	212	1.2
2006	17,439	-58	-0.3
2007	17,698	259	1.5
2008	17,670	-28	-0.2
2009	17,100	-570	-3.2
2010	17,088	-12	-0.1

AVERAGE ANNUAL GROWTH

	MW Per Year	% Per Year
History (2005 to 2010)	-82	-0.5
History (1995 to 2010)	140	0.9
Spring 2011 Forecast (2010 to 2026)	353	1.8
Fall 2010 Forecast (2010 to 2026)	333	1.7

SPRING 2011 FORECAST / Fall 2010 FORECAST

Year	MW	Growth MW	Growth %	MW	SPRING 2011 vs. FALL 2010 MW	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	17,557	469	2.7	17,418	139	0.8	330
2012	17,812	255	1.5	17,659	153	0.9	241
2013	18,245	433	2.4	17,893	352	2.0	234
2014	18,680	435	2.4	18,216	464	2.5	323
2015	19,032	352	1.9	18,582	450	2.4	366
2016	19,476	444	2.3	18,983	493	2.6	401
2017	19,877	401	2.1	19,372	505	2.6	389
2018	20,265	388	2.0	19,790	475	2.4	418
2019	20,644	379	1.9	20,172	472	2.3	382
2020	20,901	257	1.2	20,498	403	2.0	326
2021	21,214	313	1.5	20,788	426	2.0	290
2022	21,530	316	1.5	21,101	429	2.0	313
2023	21,836	306	1.4	21,425	411	1.9	324
2024	22,135	299	1.4	21,759	376	1.7	334
2025	22,465	330	1.5	22,085	380	1.7	326
2026	22,733	268	1.2	22,423	310	1.4	338

(Load Forecast Pg 25)

Winter Peak

The Summer peak forecast represents the maximum coincidental demand during the summer season on the Duke Energy Carolinas system. It includes all Retail classes as well as wholesale customers to whom Duke provides full or partial service. It represents the Integrated Resource Plan load that Duke is obligated to serve. It is expressed in MW at the point of generation and includes losses.

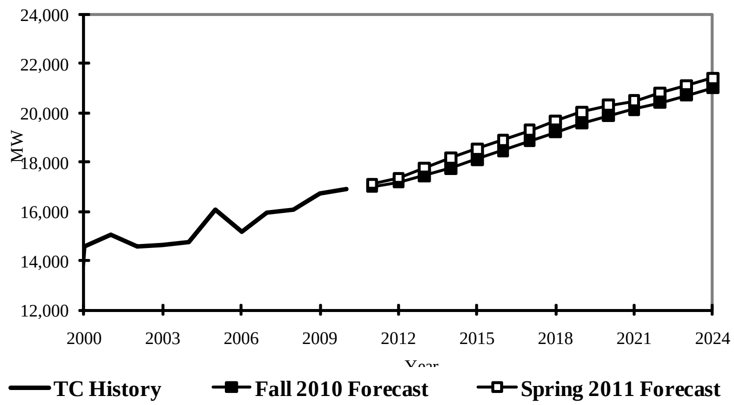
Adjustments were made to the peak forecast associated with price increases due to a Carbon Tax starting in 2015 and peak additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast beginning in 2011. Adjustments were also made to reflect the impacts of utility sponsored energy efficiency programs.

Growth Forecasts

The new Forecast projects an incremental growth of 323 MW or 1.7% per year from 2011-2026. The previous forecast growth was 308 MW or 1.6% per year from 2011-2026.

(Load Forecast Pg 26)

System Winter MW



HISTORY / **AVERAGE ANNUAL GROWTH**

Year	Weather Normalized MW	Growth MW	Growth %		MW Per Year	% Per Year
2001	15,071	486	3.3			
2002	14,565	-506	-3.4			
2003	14,626	61	0.4			
2004	14,770	144	1.0			
2005	16,054	1,285	8.7			
2006	15,193	-861	-5.4	History (2005 to 2010)	168	1.0
2007	15,936	742	4.9	History (2000 to 2010)	231	1.5
2008	16,065	130	0.8			
2009	16,723	657	4.1	Spring 2011 Forecast (2010 to 2026)	316	1.7
2010	16,893	170	1.0	Fall 2010 Forecast (2010 to 2026)	296	1.6

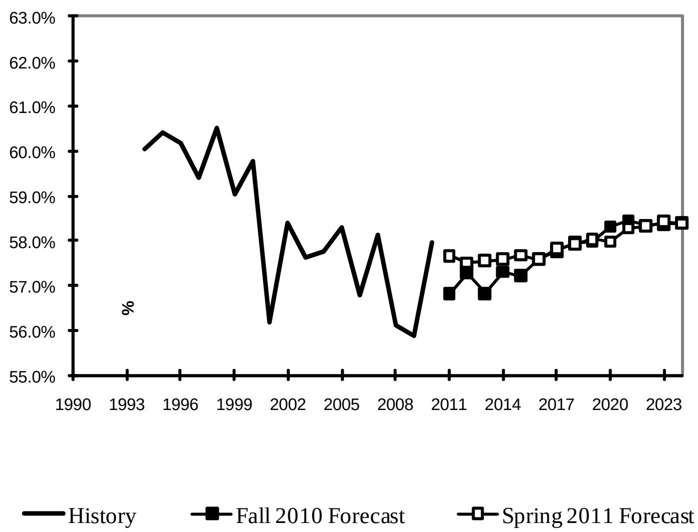
SPRING 2011 FORECAST / **Fall 2010 FORECAST**

Year	MW	Growth MW	Growth %	MW	SPRING 2011 vs. FALL 2010 MW	SPRING 2011 vs. FALL 2010 %	Fall 2010 Growth Per Year
2011	17,115	222	1.3	17,004	111	0.7	111
2012	17,359	243	1.4	17,204	155	0.9	200
2013	17,773	414	2.4	17,455	318	1.8	251
2014	18,177	404	2.3	17,767	410	2.3	312
2015	18,543	366	2.0	18,111	432	2.4	344
2016	18,891	348	1.9	18,485	406	2.2	374
2017	19,305	414	2.2	18,848	457	2.4	363
2018	19,694	388	2.0	19,234	460	2.4	386
2019	20,042	348	1.8	19,582	460	2.4	348
2020	20,304	262	1.3	19,873	431	2.2	291
2021	20,492	188	0.9	20,150	342	1.7	277
2022	20,835	343	1.7	20,434	401	2.0	284
2023	21,124	288	1.4	20,729	395	1.9	295
2024	21,412	288	1.4	21,028	384	1.8	299
2025	21,697	285	1.3	21,326	371	1.7	298
2026	21,956	259	1.2	21,631	325	1.5	305

(Load Forecast Pg 27)

Load Factor

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 Forecast Pg 28)

APPENDIX C: SUPPLY-SIDE SCREENING

The following sets of estimated Levelized Busbar Cost[6] charts provide an economic comparison of the technologies in their respective categories. Busbar charts 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[7]. 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. The Renewables Busbar Chart shows a single point for each type of resource at the particular capacity factor specified. Also, the capacity (MW size) of the Baseload and Peak/Intermediate technology categories are listed in the chart legends, and tabular listings below. 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).

Busbar Charts by Technology Category – Base 2011 Fundamentals Carbon Scenario

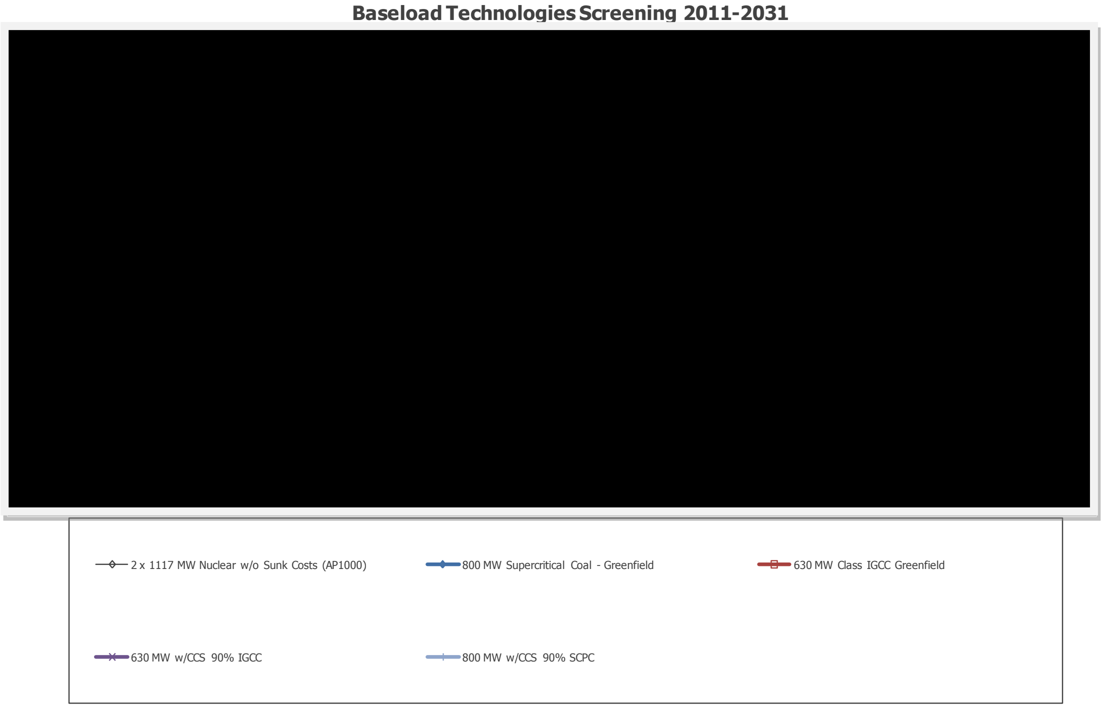
Baseload

The following technologies are found on the baseload technologies screening chart:

1) 2 x 1,117 MW Nuclear
2) 800 MW Supercritical Coal
3) 800 MW Supercritical Coal with Carbon Capture and Storage at 90%
4) 630 MW IGCC Coal
5) 630 MW IGCC with Carbon Capture and Storage at 90%

[6] 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.

[7] 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.



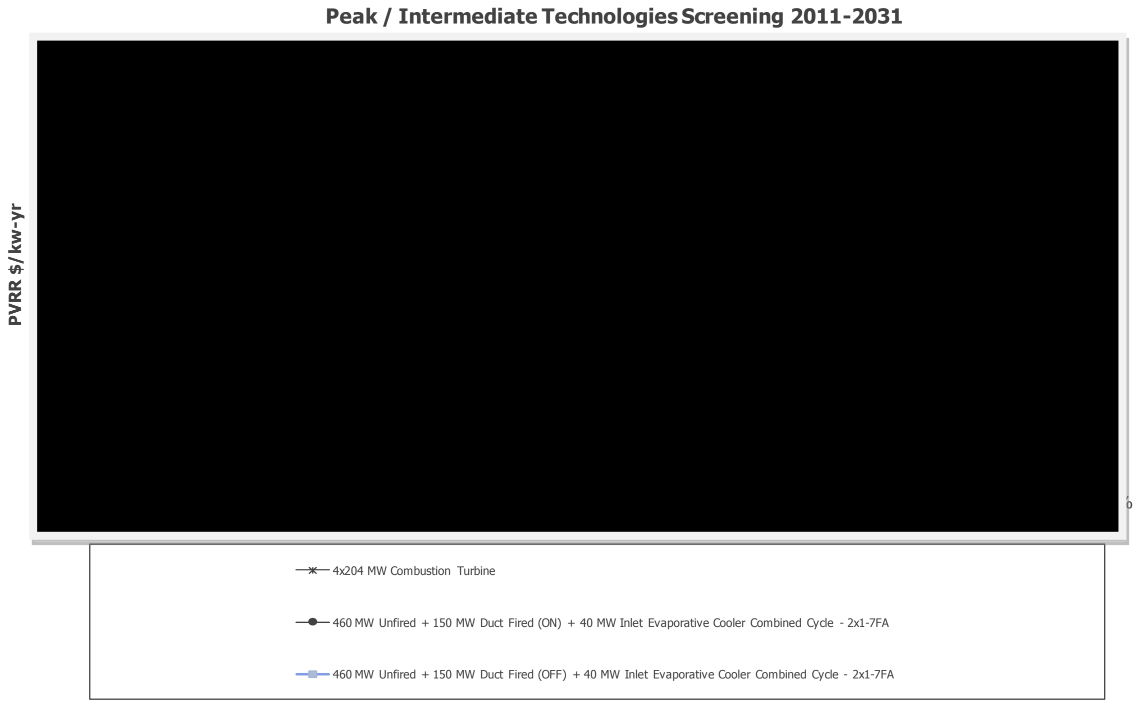
New un-sequestered coal generation is the lowest cost baseload option. However, baseload coal was not considered in the detailed portfolio evaluation due to EPA's pursuit of GHG regulation on new and existing coal units.

Nuclear becomes economic compared to IGCC at about 60% capacity factor. It is important to note that the capital and operating costs for carbon capture technology are still the subjects of ongoing industry studies and research, along with the feasibility and costs of geological sequestration of CO_2 once it is captured. The sequestration geology is not favorable in the Carolinas.

Intermediate and Peaking

The following technologies are found on the peak/intermediate technologies screening chart:

1) 4x204 MW Simple-Cycle CT
2) 460 MW Unfired + 150 MW Duct Fired + 40 MW Inlet Evaporative Cooler Combined Cycle (650MW total)
3) 460 MW Unfired + 40 MW Inlet Evaporative Cooler Combined Cycle (500 MW total)



The simple-cycle CT unit makes up the lower envelope of the curves up to about 35% capacity factor, where the unfired option is the most economic over the rest of the capacity factor range.

Duct firing in a CC unit is a process to introduce more fuel (heat) directly into the combustion turbine exhaust (waste heat) stream, by way of a duct burner, to increase the temperature of the exhaust gases entering the Heat Recovery Steam Generator (HRSG). This additional heat allows the production of additional steam to produce more electricity in the steam (bottoming) cycle of a CC unit. It is a low cost ($/kW installed cost) way to increase power (MW) output during times of very high electrical demands and/or system emergencies. However, it adversely impacts the efficiency (raises the heat rate) and thereby dramatically increases the operating cost of a CC unit (notice the much steeper slope of the duct firing "On" cases in the screening curve charts). Duct firing also increases emissions, generally resulting in a very limited number of hours per year that duct firing is allowed within operating permits.

Within the screening curves, the estimated capital cost for a combined cycle unit always includes the duct burner and related equipment. The two curves, one "On," and one "Off," are intended to show the efficiency loss (steeper slope) when the duct burner is "On", but also show that even with the duct burner "On" the efficiency (slope) is still better than a simple-cycle CT unit (much steeper slope). The duct burner "Off" curve is where the combined cycle unit will operate most of the time, and this is the one best compared with all other candidate technologies

Renewables

The following technologies are found on the renewable technologies screening chart:

1) 150 MW Wind
2) 25 MW Solar Photovoltaic
3) 100 MW Woody Biomass

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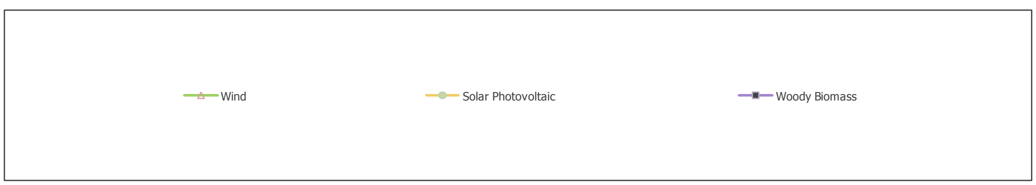

One must remember that busbar charts comparisons involving some renewable resources, particularly wind and solar resources can be somewhat misleading because these resources do not contribute their full installed capacity at the time of the system peak[8]. Since busbar charts attempt to levelize and 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.

Since these renewable technologies either have no CO_2 emissions or are deemed to be carbon neutral, the cost of CO_2 emissions does not impact their operating cost. Wind appears to be the least cost renewable alternative through its maximum practical capacity

[8] 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.

factor range. Woody biomass is next throughout its entire capacity range. The Solar Photovoltaic is the most costly renewable within the renewable category.

APPENDIX D: DEMAND SIDE MANAGEMENT ACTIVATION HISTORY

DEMAND-SIDE MANAGEMENT ACTIVATION HISTORY

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
09/10-06/11	Air Conditioners	Economic Event	113 MW	Verifying	06/21/2011
	Standby Generator	Emergency Event	48 MW	54 MW	06/01/2011
		Monthly Tests			
	Interruptible Service	Emergency Event	145 MW	147 MW	06/01/2011
		Communication Test	N/A	N/A	05/12/2011
	PowerShare Generator	Emergency Event	11 MW	8 MW	06/01/2011
	PowerShare Mandatory	Emergency Event	280 MW	325 MW	06/01/2011
	PowerShare Voluntary	Economic Event	N/A	14 MW	12/15/2010
		Economic Event	N/A	1 MW	06/01/2011
		Economic Event	N/A	16 MW	06/02/2011
	PowerShare CallOption	Economic Event	0.2 MW	0.2 MW	12/14/2010
		Economic Event	0.2 MW	0.2 MW	12/15/2010
		Economic Event	0.2 MW	0.2 MW	01/13/2011
9/09 – 9/10*	Air Conditioners	Economic Event	46 MW**	50 MW	6/14/2010
		Economic Event	50 MW	45 MW	6/15/2010
		Economic Event	103 MW**	102 MW	6/23/2010
		Economic Event	90 MW	81 MW	07/07/2010
		Economic Event	90 MW	87 MW	07/08/2010
		Economic Event	99 MW	103 MW	07/22/2010
		Economic Event	114 MW	114 MW	07/23/2010
		Economic Event	107 MW	107 MW	08/05/2010
	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	6/8/2010
	PowerShare Voluntary	Economic Event	N/A	13 MW	6/15/2010
		Economic Event	N/A	17 MW	6/23/2010
		Economic Event	N/A	9 MW	7/7/2010
		Economic Event	N/A	7 MW	7/8/2010
		Economic Event	N/A	7 MW	7/23/2010
		Economic Event	N/A	28 MW	7/29/2010
		Economic Event	N/A	5 MW	8/4/2010
		Economic Event	N/A	7 MW	8/5/2010
	PowerShareCallOption	Economic Event	0.2 MW	0.2 MW	07/07/2010
		Economic Event	0.2 MW	0.2 MW	07/08/2010
		Economic Event	0.2 MW	0.2 MW	08/05/2010
9/08 -9/09	Air Conditioners	Cycling Event		30 MW	8/10/2009
		SOC Full Shed Test	N/A	N/A	8/11/2009
	Water Heaters				
	Standby Generators				
	Interruptible Service	Communication Test	N/A	N/A	5/6/2009

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
9/07 – 9/08	Air Conditioners				
	Water Heaters				
	Standby Generators				
	Interruptible Service	Communication Test	N/A	N/A	5/6/2008
8/06 – 8/07	Air Conditioners	Cycling Test	N/A	N/A	8/30/2007
		Load Test (PLC only)	N/A	N/A	8/7/2007
		Load Test	120 MW	88 MW	8/2/2007
	Water Heaters	Cycling Test	N/A	N/A	8/30/2007
		Load Test (PLC only)	N/A	N/A	8/7/2007
		Load Test	2 MW	Included in Air Conditioners.	8/2/2007
	Standby Generators	Capacity Need	82 MW	88 MW	8/10/2007
		Capacity Need	82 MW	90 MW	8/9/2007
		Capacity Need	82 MW	79 MW	8/8/2007
		Capacity Need	82 MW	85 MW	8/1/2006
		Monthly Test			
	Interruptible Service	Capacity Need	306 MW	301 MW	8/10/2007
		Capacity Need	306 MW	323 MW	8/9/2007
		Capacity Need	341 MW	391 MW	8/1/2006
		Communication Test	N/A	N/A	4/24/2007
8/05 – 7/06	Air Conditioners	Load Test	110 MW	107 MW	6/21/2006
		Cycling Test	N/A	N/A	9/21/2005
		Cycling Test	N/A	N/A	9/20/2005
	Water Heaters	Load Test	2 MW	Included in Air Conditioners.	6/21/2006
		Cycling Test	N/A	N/A	9/21/2005
		Cycling Test	N/A	N/A	9/20/2005
	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	4/25/2006
8/04 – 7/05	Air Conditioners	Load Test	140 MW	148 MW	7/21/2005
		Cycling Test	N/A	N/A	8/19/2004
		Cycling Test	N/A	N/A	8/18/2004
	Water Heaters	Load Test	2 MW	Included in Air Conditioners.	7/21/2005
		Cycling Test	N/A	N/A	8/19/2004
		Cycling Test	N/A	N/A	8/18/2004
	Standby Generators	Monthly Test			
8/03 – 7/04	Air Conditioners	Load Test	110 MW	170 MW	7/14/2004
		Cycling Test	N/A	N/A	8/20/2003
	Water Heaters	Cycling Test	N/A	N/A	8/20/2003
	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	4/28/2004

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
8/02 – 7/03	Air Conditioners	Load Test	120 MW	195 MW	7/16/2003
		Cycling Test	N/A	N/A	6/18/2003
		Cycling Test	N/A	N/A	9/18/2002
		Load Test	82 MW	122 MW	8/21/2002
	Water Heaters	Load Test	5 MW	Included in Air Conditioners.	7/16/2003
		Cycling Test	N/A	N/A	6/18/2003
		Cycling Test	N/A	N/A	9/18/2002
		Load Test	6 MW	Included in Air Conditioners.	8/21/2002
	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/7/2003
		Communication Test	N/A	N/A	11/19/2002
8/01 – 7/02	Air Conditioners	Cycling Test	N/A	N/A	7/17/2002
		Cycling Test	N/A	N/A	6/19/2002
		Cycling Test	N/A	N/A	8/31/2001
		Load Test	150 MW	151 MW	8/17/2001
	Water Heaters	Cycling Test	N/A	N/A	7/17/2002
		Cycling Test	N/A	N/A	6/19/2002
		Cycling Test	N/A	N/A	8/31/2001
		Load Test	6 MW	Included in Air Conditioners.	8/17/2001
	Standby Generators	Capacity Need	80 MW	20 MW Estimation due to communication problems.	6/13/2002
		Monthly Test			
	Interruptible Service	Capacity Need	403 MW	370 MW	6/13/2002
		Communication Test	N/A	N/A	4/17/2002
8/00 – 7/01	Air Conditioners	Communication Test	N/A	N/A	9/14/2000
	Water Heaters	Communication Test	N/A	N/A	9/14/2000
	Standby Generators	Capacity Need	70 MW	70 MW	8/7/2000
		Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/8/2001
7/99 – 8/00	Air Conditioners	Load Test	170-200 MW	175-200 MW	6/15/2000
	Water Heaters	Load Test	6 MW	Included in Air Conditioners.	6/15/2000
	Standby Generators	Capacity Need	70 MW	70 MW	7/2/2000
		Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/17/2000
		Communication Test	N/A	N/A	10/20/1999

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
9/98 – 7/99	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/11/1999
		Communication Test	N/A	N/A	10/27/1998
9/97 – 9/98	Air Conditioners	Load Test	180 MW	170 MW	8/18/1998
	Water Heaters	Load Test	7 MW	7 MW	8/18/1998
		Communication Test	N/A	N/A	5/29/1998
	Standby Generators	Capacity Need	68 MW	58 MW	8/31/1998
		Capacity Need	68 MW	58 MW	6/12/1998
		Monthly Test			
	Interruptible Service	Capacity Need	570 MW	500 MW	8/31/1998
		Communication Test	N/A	N/A	5/29/1998
9/96 – 9/97	Air Conditioners	Communication Test	N/A	N/A	6/17/1997
	Standby Generators	Capacity Need	62 MW	50 MW	7/28/1997
		Capacity Need	62 MW	50 MW	7/15/1997
		Capacity Need	62 MW	50 MW	7/14/1997
		Capacity Need	62 MW	50 MW	12/20/1996
		Monthly Test			
	Interruptible Service	Capacity Need	650 MW	550 MW	7/28/1997
		Communication Tests	N/A	N/A	6/17/1997
		Communication Tests	N/A	N/A	10/16/1996

*Starting in 2010, a new category of event called an Economic Event has been added to the table.
**Corrected numbers from previous table filed.

APPENDIX E: PROPOSED GENERATING UNITS AT LOCATIONS NOT KNOWN

A list of proposed generating units at locations not known with capacity, plant type, and date of operation included to the extent known:

Line 12 of the LCR Table for Duke Energy Carolinas identifies cumulative future resource additions needed to meet customer load reliably. Resource additions may be a combination of short/long-term capacity purchases from the wholesale market, capacity purchase options, and building or contracting of new generation

APPENDIX F: TRANSMISSION LINES AND OTHER ASSOCIATED FACILITIES PLANNED OR UNDER CONSTRUCTION

There are no significant planned construction projects on the Duke Energy Carolinas' transmission system.

In addition, NCUC Rule R8-62(p) requires the following information.

1. For existing lines, the information required on FERC Form 1, pages 422, 423, 424 and 425: (Please see Appendix J for Duke Energy Carolinas' current FERC Form 1 pages 422, 423, 422.1, 423.1, 422.2, 423.2, 423.3, 424, 425, and 450.1.)

2. For lines under construction:
   - Commission docket number
   - Location of end point(s)
   - Length
   - Range of right-of-way width
   - Range of tower heights
   - Number of circuits
   - Operating voltage
   - Design capacity
   - Date construction started
   - Projected in-service date

3. For all other proposed lines, as the information becomes available:

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINE STATISTICS

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3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Antioch Tie	Appalachian Power	525.00	525.00	Tower	27.67		1
2	Jocassee Tie	Bad Creek Hydro	525.00	525.00	Tower	9.25		1
3	Jocassee Tie	McGuire Switching	525.00	525.00	Tower	119.86		1
4	McGuire Switching	Antioch Tie	525.00	525.00	Tower	54.40		1
5	McGuire Switching	Woodleaf Switching	525.00	525.00	Tower	29.95		1
6	Newport Tie	Progress Energy Rockingham	525.00	525.00	Tower	48.66		1
7	Newport Tie	McGuire Switching	525.00	525.00	Tower & Pole	32.24		1
8	Oconee Nuclear	Newport Tie	525.00	525.00	Tower	108.12		1
9	Oconee Nuclear	South Hall	525.00	525.00	Tower & Pole	22.50		1
10	Oconee Nuclear	Jocassee Tie	525.00	525.00	Tower	20.90		1
11	Pleasant Garden Tie	Parkwood Tie	525.00	525.00	Tower	49.65		1
12	Woodleaf Switching	Pleasant Garden Tie	525.00	525.00	Tower	53.07		1
13								
14	TOTAL 525 KV LINES					576.27		12
15								
16	Allen Steam	Catawba Nuclear	230.00	230.00	Tower	10.86		2
17	Allen Steam	Riverbend Steam	230.00	230.00	Tower	12.49		2
18	Allen Steam	Winecoff Tie	230.00	230.00	Tower	32.22		2
19	Allen Steam	Woodlawn Tie	230.00	230.00	Tower & Pole	8.63		2
20	Anderson Tie	Hodges Tie	230.00	230.00	Tower	25.79		2
21	Antioch Tie	Wilkes Tie	230.00	230.00	Tower	4.29		2
22	Beckerdite Tie	Belews Creek Steam	230.00	230.00	Tower	24.60		2
23	Beckerdite Tie	Pleasant Garden Tie	230.00	230.00	Tower	28.48		2
24	Belews Creek Steam	Ernest Switching Station	230.00	230.00	Tower	13.71		2
25	Belews Creek Steam	North Greensboro Tie	230.00	230.00	Tower	21.65		2
26	Belews Creek Steam	Pleasant Garden Tie	230.00	230.00	Tower & Pole	38.72		2
27	Belews Creek Steam	Rural Hall Tie	230.00	230.00	Tower	18.32		2
28	Bobwhite Switching	North Greensboro Tie	230.00	230.00	Tower	3.83		2
29	Buck Tie	Beckerdite Tie	230.00	230.00	Tower	23.63		2
30	Catawba Nuclear	Newport Tie	230.00	230.00	Tower & Pole	10.36		2
31	Catawba Nuclear	Pacolet Tie	230.00	230.00	Tower	41.26		2
32	Catawba Nuclear	Peacock Tie	230.00	230.00	Tower	14.85		2
33	Catawba Nuclear	Ripp Switching Station	230.00	230.00	Tower	24.44		2
34	Central Tie	Anderson Tie	230.00	230.00	Tower	23.12		2
35	Cliffside Steam	Pacolet Tie	230.00	230.00	Tower	23.01		2
36					TOTAL	8,259.59		162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINE STATISTICS

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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Cliffside Steam	Shelby Tie	230.00	230.00	Tower	14.16		2
2	Cowans Ford Hydro	McGuire Switching	230.00	230.00	Tower	1.67		2
3	East Durham Tie	Parkwood Tie	230.00	230.00	Tower	19.26		2
4	Eno Tap Bent	Progress Energy (Roxboro)	230.00	230.00	Tower	13.74		2
5	Eno Tap Bent	East Durham Tie	230.00	230.00	Tower	15.78		2
6	Ernest Switching Station	Sadler Tie	230.00	230.00	Tower	12.61		2
7	Harrisburg Tie	Oakboro Tie	230.00	230.00	Tower	21.52		2
8	Hartwell Hydro	Anderson Tie	230.00	230.00	Tower	11.16		2
9	Jocassee Switching	Shiloh Switching	230.00	230.00	Tower	22.52		2
10	Jocassee Switching	Tuckasegee Tie	230.00	230.00	Tower	26.62		2
11	Lakewood Tie	Riverbend Steam	230.00	230.00	Tower	10.64		2
12	Lincoln CT	Longview Tie	230.00	230.00	Tower	30.96		2
13	Longview Tie	McDowell Tie	230.00	230.00	Tower	31.93		2
14	Marshall Steam	Beckerdite Tie	230.00	230.00	Tower	52.61		2
15	Marshall Steam	Longview Tie	230.00	230.00	Tower	29.04		2
16	Marshall Steam	McGuire Switching	230.00	230.00	Tower	13.76		2
17	Marshall Steam	Stamey Tie	230.00	230.00	Tower	13.44		2
18	Marshall Steam	Winecoff Tie	230.00	230.00	Tower	24.35		2
19	McGuire Switching	Harrisburg Tie	230.00	230.00	Tower	36.27		2
20	Mitchell River Tie	Antioch Tie	230.00	230.00	Tower & Pole	16.90		2
21	Mitchell River Tie	Rural Hall Tie	230.00	230.00	Tower	26.85		2
22	Morningstar Tie	Oakboro Tie	230.00	230.00	Tower	32.55		1
23	North Greenville Tie	Central Tie	230.00	230.00	Tower & Pole	26.22		2
24	North Greenville Tie	Shiloh Switching	230.00	230.00	Tower	8.96		2
25	Newport Tie	Morningstar Tie	230.00	230.00	Tower & Pole	33.59		1
26	Newport Tie	SCE&G (Parr)	230.00	230.00	Tower	45.38		1
27	Oakboro Tie	Progress Energy Rockingham	230.00	230.00	Tower	5.13		2
28	Oconee Nuclear	Central Tie	230.00	230.00	Tower	17.62		2
29	Oconee Nuclear	Jocassee Switching	230.00	230.00	Tower & Pole	12.28		2
30	Oconee Nuclear	North Greenville Tie	230.00	230.00	Tower & Pole	29.25		2
31	Pacolet Tie	Tiger Tie	230.00	230.00	Tower	27.96		2
32	Peach Valley Tie	Tiger Tie	230.00	230.00	Tower	15.69		2
33	Pisgah Tie	Progress Energy Skyland Stm	230.00	230.00	Tower	14.41		2
34	Pleasant GardenTie	Eno Tie	230.00	230.00	Tower	42.85		2
35	Ripp Switching	Riverview Switching	230.00	230.00	Tower	9.70		2
36					TOTAL	8,259.59		162

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 07/20/2011	Year/Period of Report End of 2010/Q4

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	Ripp Switching	Shelby Tie	230.00	230.00	Tower	9.96		2
2	Riverbend Steam	Lincoln CT	230.00	230.00	Tower & Pole	11.59		2
3	Riverbend Steam	McGuire Switching	230.00	230.00	Tower	5.61		2
4	Riverbend Steam	Ripp Switching	230.00	230.00	Tower	30.12		2
5	Riverview Switching	Peach Valley Tie	230.00	230.00	Tower	19.33		2
6	SCE&G (Parr)	Bush River Tie	230.00	230.00	Tower	17.63		1
7	Shady Grove Tap	Shady Grove Tie	230.00	230.00	Tower	7.80		2
8	Shiloh Switching	Pisgah Tie	230.00	230.00	Tower	21.85		2
9	Shiloh Switching	Tiger Tie	230.00	230.00	Tower	21.46		2
10	Stamey Tie	Mitchell River Tie	230.00	230.00	Tower	35.92		2
11	Tiger Tie	North Greenville Tie	230.00	230.00	Tower	18.38		2
12	Winecoff Tie	Buck Tie	230.00	230.00	Tower	24.05		2
13								
14	TOTAL 230 KV LINES					1,395.31		130
15								
16	Nantahala Hydro	Webster Tie	161.00	161.00	Tower	12.66		1
17	Nantahala Tie	Marble Tie	161.00	161.00	Tower	16.85		2
18	Nantahala Hydro	Santeetlah Plt Robbinsville	161.00	161.00	Tower	18.88		2
19	Tuckaseegee Tie	West Mill Tie	161.00	161.00	Tower & Pole	10.42		2
20	Tuckasegee Tie	Thorpe Hydro	161.00	161.00	Tower & Pole	3.25		1
21	Wesbter Tie	Lake Emory S. S.	161.00	161.00	Tower	11.93		1
22	West Mill Tie	Lake Emory S. S.	161.00	161.00	Tower	6.78		1
23	West Mill Tie	Nantahala Tie	161.00	161.00	Tower	13.08		1
24	West Mill Tie	East Bryson	161.00	161.00	Tower & Pole	13.30		3
25								
26	TOTAL 161 KV LINES					107.15		14
27								
28	Dan River Steam	Appalachian Power	138.00	138.00	Tower & Pole	6.54		1
29	115 KV Lines		115.00	115.00	Tower & Pole	54.88		1
30	100 KV Lines		100.00	100.00	Tower	2,884.35		
31	100 KV Lines		100.00	100.00	Pole	640.25		
32	100 KV Lines		100.00	100.00	Underground	2.08		
33								
34	TOTAL 100 - 138 KV LINES					3,588.10		2
35								
36					TOTAL	8,259.59		162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	66 KV Lines		66.00	66.00	Pole	104.88		1
2								
3	TOTAL 66 KV LINES					104.88		1
4								
5	44 KV Lines		44.00	44.00	Tower	183.26		
6	44 KV Lines		44.00	44.00	Pole	2,178.66		
7	44 KV Lines		44.00	44.00	Underground	0.34		1
8								
9	TOTAL 44 KV LINES					2,362.26		1
10								
11	33 KV Lines		33.00	33.00	Pole	14.65		
12	24 KV Lines		24.00	24.00	Pole	84.64		
13	24 KV Lines		24.00	24.00	Underground	0.44		1
14	12 KV Lines		12.00	12.00	Tower & Pole	25.67		
15	12 KV Lines		12.00	12.00	Underground	0.22		1
16								
17	TOTAL 12-33 KV LINES					125.62		2
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	8,259.59		162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses bome by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2515								1
2515								2
2515								3
2515								4
2515								5
2515								6
2515								7
2515								8
2515								9
2515								10
2515								11
2515								12
	20,355,902	99,736,823	120,092,725					13
	20,355,902	99,736,823	120,092,725					14
								15
1272								16
1272								17
954 & 1272								18
2156								19
954								20
954								21
2156								22
954								23
1272								24
2156								25
2156								26
2156								27
2156								28
954								29
1272								30
954								31
1272								32
1272								33
954								34
954								35
	161,478,509	1,228,987,846	1,390,466,355	715,074	15,727,295		16,442,369	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954								1
795								2
1272								3
1272								4
1272								5
1272								6
954								7
954								8
2156								9
1272								10
954								11
795								12
954								13
954								14
1272								15
1272								16
954								17
1272								18
1272								19
954								20
954								21
954								22
954								23
954								24
954								25
954								26
954								27
1272								28
2156								29
1272								30
954								31
795								32
954								33
954								34
795								35
	161,478,509	1,228,987,846	1,390,466,355	715,074	15,727,295		16,442,369	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954								1
795								2
1272								3
795								4
795								5
954								6
2515								7
954								8
1272								9
954								10
954								11
954								12
	41,317,981	220,519,462	261,837,443					13
	41,317,981	220,519,462	261,837,443					14
								15
795								16
795								17
636								18
795								19
397.5								20
636								21
795								22
795								23
954								24
	3,422,657	73,995,073	77,417,730					25
	3,422,657	73,995,073	77,417,730					26
								27
477								28
								29
								30
								31
								32
	68,746,288	567,900,634	636,646,922					33
	68,746,288	567,900,634	636,646,922					34
								35
	161,478,509	1,228,987,846	1,390,466,355	715,074	15,727,295		16,442,369	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) ☐ An Original (2) ☒ A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
	4,464,582	21,632,669	26,097,251					2
	4,464,582	21,632,669	26,097,251					3
								4
								5
								6
								7
	22,606,882	240,793,751	263,400,633					8
	22,606,882	240,793,751	263,400,633					9
								10
								11
								12
								13
								14
								15
	564,217	4,409,434	4,973,651					16
	564,217	4,409,434	4,973,651					17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
				715,074	15,727,295		16,442,369	35
	161,478,509	1,228,987,846	1,390,466,355	715,074	15,727,295		16,442,369	36

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Duke Energy Carolinas, LLC	(1) __ An Original (2) X A Resubmission	(Mo, Da, Yr) 07/20/2011	2010/Q4

FOOTNOTE DATA

Schedule Page: 422 Line No.: 1 Column: h

For column (h) the number of circuits - 1 & 2

Schedule Page: 422 Line No.: 1 Column: i

All Conductors in column (i) are ACSR shown in MCM.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [ ] An Original (2) [X] A Resubmission	07/20/2011	End of 2010/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Overhead: New Lines						
2	Beatles Ford Ret Tap		1.70	Pole	8.00	1	
3	Parkwood Ret Tap		0.11	Pole	9.00	1	
4	Cleveland County School Tap		0.84	Towers	20.00	2	
5	Cathey Rd Tap		0.90	Pole	11.00	1	
6	Institute for B & H Safety Tap		0.19			1	
7	Piercetown to Plainview Tap		5.30		9.00	2	
8	Indian land & Charlotte #2 Tap		0.04	Pole	75.00	1	
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23	Overhead: Major Rebuild						
24	Ebert Rd Tap	Buck Tie - Winston Tie	2.53		9.00	2	
25	Buzzard Roost Hydro	International Paper Tap	5.46		8.00	2	
26	Central Tie	Greenlawn Switching Station	0.28		96.00	2	
27	Kent Line	Hillside Line to Shoal Line	0.02	Pole	65.00	1	
28	Armory Bent	N Greenwood Retail	0.75		17.00	2	
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		18.12		327.00	18	

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 07/20/2011	Year/Period of Report End of 2010/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
556.5	ACSR		100	461,933	1,114,037	682,798		2,258,768	2
1272.0	ACSR		100		24,013	46,764		70,777	3
556.0	ACSR		44	15,393	356,495	218,497		590,385	4
336.0	ACSR		100	748,190	286,710	175,725		1,210,625	5
556.0	ACSR		100		83,646	51,268		134,914	6
954.0	ACSR		100		3,070,808	1,882,108		4,952,916	7
336.0	ACSR		44		33,050	20,256		53,306	8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
954.0	ACSR		100		1,114,259	682,933		1,797,192	24
556.0	ACSR		100		1,535,851	941,328		2,477,179	25
477.0	ACSR		100		3,473,526	2,128,936		5,602,462	26
556.0	ACSR		44		247,741	151,840		399,581	27
556.0	ACSR		100		549,952	337,068		887,020	28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				1,225,516	11,890,088	7,319,521		20,435,125	44

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Duke Energy Carolinas, LLC	(1) _ An Original (2) X A Resubmission	(Mo, Da, Yr) 07/20/2011	2010/Q4

FOOTNOTE DATA

Schedule Page: 424 Line No.: 1 Column: l

For all of column "l", "m" and "n" all or portion of the cost is in account 106

Schedule Page: 424 Line No.: 6 Column: d

No structures used in the new line

Schedule Page: 424 Line No.: 7 Column: d

Towers & Poles used in the new line

Schedule Page: 424 Line No.: 24 Column: d

Towers & Poles used in the new line

Schedule Page: 424 Line No.: 25 Column: d

Towers & Poles used in the new line

Schedule Page: 424 Line No.: 26 Column: d

Towers & Poles used in the new line

Schedule Page: 424 Line No.: 28 Column: d

Towers & Poles used in the new line

GENERATION AND ASSOCIATED TRANSMISSION FACILITIES SUBJECT TO CONSTRUCTION DELAYS

A list of any generation and associated transmission facilities under construction which have delays of over six months in the previously reported in-service dates and the major causes of such delays. Upon request from the NCUC Staff, the reporting utility shall supply a statement of the economic impact of such delays:

There are no delays over six months in the stated in-service dates.

2011 FERC Form 715

The 2011 FERC Form 715 filed April 2011, is confidential and filed under seal.

APPENDIX G: OTHER INFORMATION (ECONOMIC DEVELOPMENT)

Customers Served Under Economic Development:

In the NCUC Order issued in Docket No. E-100, Sub 97, dated November 15, 2002, the NCUC ordered North Carolina utilities to review the combined effects of existing economic development rates within the approved IRP process and file the results in its short-term action plan. There are no significant changes to the incremental load (demand) for which customers are receiving credits under economic development rates and/or self-generation deferral rates (Rider EC), as well as economic redevelopment rates (Rider ER) since the 2010 Carolinas IRP.

APPENDIX H: NON-UTILITY GENERATION/CUSTOMER-OWNED GENERATION/STAND-BY GENERATION:

In NCUC Order in Docket No. E-100, Sub 111, dated July 11, 2007, the NCUC required North Carolina utilities to provide a separate list of all non-utility electric generating facilities in the North Carolina portion of their control areas, including customer-owned and standby generating facilities, to the extent possible. Duke Energy Carolinas' response to that Order was based on the best available information, and the Company has not attempted to independently validate it. In addition, some of that information duplicates data that Duke Energy Carolinas supplies elsewhere in this IRP.

The Company has continued to add small non-utility electric generation in 2011. A separate list is not included in the 2011 IRP, however the total additions are reflected in Tables 5.E and 5.F, and the Company has included a full list in its annual status report filed in Docket No. E-100, Sub 41B.

APPENDIX I: WHOLESALE PROJECTIONS FROM EXISTING AND POTENTIAL CUSTOMERS

Table I.1 below provides the historical and projected growth in peak loads for the Company's wholesale customers. The values are summer peaks at generation. The wholesale customer growth rates vary and none are the same as the historical growth rate in Duke Energy Carolinas' retail load. With respect to wholesale sales contracts, the Company has developed econometric forecasting models for the larger wholesale customer in a process similar to that used for retail to produce MWH sales forecasts. For smaller wholesale customers, however, their forecasted growth is assumed to be the same as Duke Energy Carolinas' retail growth.

It is important to note that the growth rates for Central and NCEMC Supplemental Requirements) are primarily driven by terms of the contract. The Central Sale provides for a seven year "step-in" to Central's full load requirement such that the Company will provide 15% of Central's total member cooperative load in Duke's Balancing Authority Area requirement in 2013. This initial load requirement will be followed by subsequent 15% annual increases in load over the following six years up to a total of 100% of Central's load requirements. The NCEMC Supplemental Requirements sale is essentially a fixed quantity of capacity and energy specified by the contract

The wholesale sales contracts, shown in Table 3.D, are net of resources provided by the customer.

TABLE I.1 (CONFIDENTIAL)

[redacted]

APPENDIX J: CARBON NEUTRALITY PLAN

Greenhouse Gas Reduction Compliance Plan – Cliffside Unit 6

On January 29, 2008, the NCDAQ issued the Air Quality Permit to Duke Energy Carolinas for the Cliffside Unit 6. The Permit specifically requires that Duke Energy Carolinas implement a Greenhouse Gas Reduction Plan (Greenhouse Plan), and specifically obligates Duke Energy Carolinas to take the following actions in recognition of NCDAQ's issuance of the Permit for Cliffside Unit 6: (1) retire 800 MWs of coal capacity in North Carolina in accordance with the schedule set forth in Table J.1, which is in addition to the retirement of Cliffside Units 1 – 4; (2) accommodate, to the extent practicable, the installation and operations of future carbon control technology; and (3) take additional actions to make Cliffside Unit 6 carbon neutral by 2018.

With regard to obligation (1) identified above, as shown in Table J.1 below, Duke Energy Carolinas proposes to retire up to the following generating units to satisfy the required retirement schedule set forth in the Greenhouse Plan.

Table J.1 - Cumulative Coal Plant Retirements

	Greenhouse Plan Retirement Schedule Capacity in MW	IRP Retirement Schedule Capacity in MW (per Table 5.D)[1]	Description for IRP Retirement Schedule
by end of 2011		113	Buck 3 & 4
by end of 2012		389	Dan River 1-3
by end of 2015	350	1159	Riverbend 4 - 7, Buck 5 & 6
by end of 2016	550	1159	Note [2]
by end of 2018	**800**	**1159**	

[1] In the 2011 IRP, this data appears in Table 5.D, page 50. Plant retirements that were applicable to the first obligation were put in this table. References will be updated with the 2011 IRP.

[2] The IRP Retirement Schedule indicates that the retirements would exceed the Greenhouse Plan by close to 50%.

With respect to obligation (2) listed above, the requirement to build Cliffside Unit 6 to accommodate future carbon technologies has been met by allocating space at the 1100 acre site for this equipment and incorporating practical energy efficiency designs into the plant.

With respect to obligation (3) to render Cliffside Unit 6 carbon neutral by 2018, the proposed plan to achieve this requirement is set forth below. The Greenhouse Gas

Reduction Plan states that the plan for carbon neutrality:

may include energy efficiency, carbon free tariffs, purchase of credits, domestic and international offsets, additional retirements or reduction in fossil fuel usage as carbon free generation becomes available, and carbon reduction through the development of smart grid, plug in hybrid electric vehicles or other carbon mitigation projects. Such actions will be included in plans to be filed with the NCUC and will be subject to NCUC approval, including appropriate cost recovery of such actions. In addition, the plans shall be submitted to the Division of Air Quality, which will evaluate the effect of the plans on carbon, and provide its conclusions to the NCUC.

Duke Energy Carolinas is including the plan for carbon neutrality in this 2011 IRP in order to satisfy the requirement to file and seek approval of the plan from the NCUC as required by the NCDAQ Air Permit.

The estimated emissions reductions required to render Cliffside Unit 6 carbon neutral in 2018 is approximately 5.3 million tons of carbon dioxide (the Emission Reduction Requirement). The Company calculated the estimated emission reductions by estimating the actual tons of carbon dioxide emissions that will be released per year from Cliffside Unit 6 less 681,954 tons of carbon dioxide emissions that was historically generated from Cliffside Units 1 – 4 and will be eliminated by the retirement of these units. (See Table J.2 below.)

Table J.2 - Emission Reduction Requirement

Actions	**Tons of CO_2 Equivalent Emissions**	**Notes**
Cliffside Unit 6	6,000,000	Expected Annual Emissions (based on an approximate 90% capacity factor)
Less Cliffside Units 1 – 4	(681,954)	Average of emissions in 2007 & 2008[1]
Total Increase	**5,318,055**	**Emissions Reduction Requirement**

[1]The emissions attributable to coal plant retirements are identified as the highest two year average CO_2 emissions for the five years prior to the operations of Unit 6 in 2012, consistent with the methodology for calculating emissions for major modification under the Clean Air Act Prevention of Significant Deterioration regulations.

The Company's plan for meeting the Emissions Reductions Requirements includes actions from multiple categories and associated methodologies for determining the offset value known as "Qualifying Actions" (defined below and as further indicated in Table J.3). The Company requests approval from the NCUC of the method of calculating the Emission Reduction Requirements and emissions offset values of the Qualifying Actions during the 2011 IRP review process.

For 2018, the Company has identified approximately 9.9 million annual tons of carbon dioxide emissions reductions and a life-time credit of 600,000 tons of carbon dioxide bio-sequestration as eligible Qualifying Actions. (See Table J.3) The Qualifying Actions include the avoidance of carbon dioxide emission releases from coal plant retirements, addition of renewable resources, implementation of energy efficiency measures, nuclear and hydropower capacity upgrades. This also includes the expected retirement of coal-fired operations at Lee Units 1, 2 and 3 in South Carolina in 2015. In addition, carbon dioxide bio-sequestration offsets from the Greentrees program, which sequesters carbon as trees grow, is identified as a Qualifying Action.

While the reductions associated for retirements for each of the coal plants shall be the same each year, the reductions for the remaining Qualifying Actions will vary based on actual results for each of the categories and the then current system carbon intensity factor. The system carbon intensity factor shall be equal to the actual carbon dioxide emissions of all Company-owned generation dedicated for Duke Energy Carolina customers divided by the megawatt hours generated by those same resources (the "Conversion Factor").

<u>Table J.3</u> - Qualifying Actions for carbon dioxide emission reductions

Categories	**Tons of CO_2 Equivalent Emissions**	**Methodology Description**
Buck 3	216,202	Average of emissions in 2007 & 2008[1]
Buck 4	139,429	Average of emissions in 2007 & 2008[1]
Buck 5	606,837	Average of emissions in 2007 & 2008[1]
Buck 6	653,860	Average of emissions in 2007 & 2008[1]
Riverbend 4	462,314	Average of emissions in 2007 & 2008[1]
Riverbend 5	435,895	Average of emissions in 2007 & 2008[1]
Riverbend 6	684,010	Average of emissions in 2007 & 2008[1]
Riverbend 7	710,023	Average of emissions in 2007 & 2008[1]
Dan River 1	249,900	Average of emissions in 2007 & 2008[1]
Dan River 2	282,944	Average of emissions in 2007 & 2008[1]
Dan River 3	677,334	Average of emissions in 2007 & 2008[1]
Lee 1 [5]	335,583	Average of emissions in 2007 & 2008[1]
Lee 2 [5]	390,965	Average of emissions in 2007 & 2008[1]
Lee 3 [5]	783,658	Average of emissions in 2007 & 2008[1]
Conservation	1,189,268	In 2018, 2,973,170 MWH "Conservation and Demand Side Management Programs"[2] is multiplied by a Conversion Factor of 0.40.
Renewable Energy	1,068,370	In 2018, 610 MW per the Table 8.E "MW Nameplate Capacity".[3] Is multiplied by an assumed 30% (wind), 20% (solar), and 85% (biomass) capacity factor and a Conversion Factor of 0.40.
Bridgewater Hydro	7,997	See Note 5 in the "Assumptions of Load, Capacity, and Reserve Table" indicates 8.75 MW increase in capacity. This is multiplied by a 26% capacity factor and a Conversion Factor of 0.40.
Nuclear Uprates	560,920	Assumed 174 MW of nuclear uprates by June of 2018.[4] Assumed a 92% capacity factor and a Conversion Factor of 0.40.
Total Annual	9,455,509	

[1] The emissions attributable to coal plant retirements are identified as the highest two year average CO_2 emissions for the five years prior to the operations of Unit 6 in 2012, consistent with the methodology for calculating emissions for major modifications under the Clean Air Act Prevention of Significant Deterioration regulations. Company reserves the right to use any credits for reduction of nitrogen oxide, sulfur dioxide and carbon dioxide emissions generated by retirement of units retired under the plan consistent with provisions of State and federal law.

[2] Data is from Table 4.A, page 34 of the 2011 IRP.

[3] Data is from the Table 8.E on page 93 of the 2011 IRP. Actual nameplate capacity is 610 MW. The contribution to peak is 304 MW.

[4] Data is a portion of the total capacity addition on page 87 of 2011 IRP prior to June 2018.

[5] Lee Units 1, 2 and 3 are planned for retirement by January 1, 2015. Alternatively, Duke Energy is considering converting one or more of these units to natural gas to allow continued operation for peak

generation demand only (at a low annual capacity factor). Any CO_2 from operating with natural gas would be subtracted from the reductions shown in the table.

If the method described above is approved, Duke Energy Carolinas shall provide a compliance report (Compliance Reports) in the 2019 IRP filing indicating what Qualifying Actions were used to meet the Emission Reduction Requirement in 2018. The expected Qualifying Actions total of 9.9 million tons of emission reductions by 2018. The Company's proposed Qualifying Actions clearly demonstrate that identified reductions can more than exceed the Required Emissions Reduction estimate of 5.3 million tons. The Company therefore requests the ability to alter the mix of actions undertaken, and even to eliminate some completely, in its discretion so long as the annual emissions reductions achieved total at least 5.3 million tons in accordance with the NCDAQ Air Permit.

APPENDIX K: 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 IRP.

Requirement	Location	Reference	Updated
Forecast of Load, Supply-side Resources, and Demand-Side Resources. • 10 year history of customers & energy sales • 15 year forecast w & w/o energy efficiency • Description of supply-side resources	 Ch 3 Ch 3 Ch 5 & App C	 NC R8-60 h (i) 1(i) NC R8-60 h(i) 1(ii) NC R8-60 h(i) 1(iii)	 Yes Yes Yes
Generating Facilities • Existing Generation • Planned Generation • Non Utility Generation • Proposed Generation Units at Locations not known • Generating Units Projected to be Retired • Generating Units with plan for life extension	 Ch 5 A Ch 8 & App A Ch 5 D Ch 8 & App A Ch 5 A N/A	 NC R8-60 h (i) 2(i)(a-f) NC R8-60 h (i) 2(ii)(a-d) NC R8-60 h (i) 2(iii)	 Yes Yes Yes Yes Yes
Reserve Margin	Ch 8	NC R8-60 h (i) 3	Yes
Wholesale Contract for the Purchase and Sale of Power • Wholesale Purchase Power Contract • Request for Proposal • Wholesale power sales contracts • Wholesale projections (existing and undesignated)	 Ch 5 D Ch 5 D Ch 3 & App I App I	 NC R8-60 h (i) 4(i) NC R8-60 h (i) 4(ii) NC R8-60 h (i) 4(iii) NCUC 09 IRP req (6)	 Yes Yes Yes Yes
Transmission Facilities , planned & under construction Transmissions System Adequacy FERC Form 1 (pages 422-425) FERC Form 715	App F Ch 7 App F App F	NC R8-60 h (i) 5	Yes Yes Yes Yes
Energy Efficiency and Demand Side Management • Existing Programs • Future Programs • Rejected Programs • Consumer Education Programs • DSM projected reliance	 Ch 4 Ch 4 Ch 4 Ch 4 App D	 NC R8-60 h (i) 6(i) NC R8-60 h (i) 6(ii) NC R8-60 h (i) 6(iii) NC R8-60 h (i) 6(iv) NCUC 09 IRP req (7)	 Yes Yes Yes Yes Yes
Assessment of Alternative Supply-Side Energy Resource • Current and Future Alternative Supply-Side • Rejected Alternative Supply-Side Energy Resource	 Ch5C & App C Ch5C & App C	 NC R8-60 h (i) 7(i) NC R8-60 h (i) 7(ii)	 Yes 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 C	 NC R8-60 h (i) 9	 Yes
Other Information (economic development)	App G		No
Legislative and Regulatory Issues	Ch 6		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	Ch 1, Ch 8 & 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	Ch 8, App A		Yes
Greenhouse Gas Reduction Compliance Plan	App J		Yes