THE STATE OF SOUTH CAROLINA
In the Court of Appeals

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S.C. SUPREME COURT

Appellate Case No. 2014-001514

APPEAL FROM THE PUBLIC SERVICE COMMISSION

Docket No. 2013-392-E

In The Matter of Joint Application of Duke Energy Carolinas, LLC and North Carolina Electric Membership Corporation for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of a 750MW Combined Generating Plant Near Anderson, SC

RECORD ON APPEAL
VOLUME II OF II

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MR. HOLMAN: Mr. Chairman, the panel is available for cross-examination.

CHAIRMAN HAMILTON: Thank you, Mr. Holman. Ms. Shafeek-Horton?

MS. SHAFEEK-HORTON: No questions. Thank you.

CHAIRMAN HAMILTON: Mr. Anthony?

MR. ANTHONY: No questions.

CHAIRMAN HAMILTON: ORS?

MS. HUDSON: No questions.

CHAIRMAN HAMILTON: Commissioners?

COMMISSIONER WHITFIELD: Mr. Chairman.

CHAIRMAN HAMILTON: Commissioner Whitfield.

COMMISSIONER WHITFIELD: Thank you, Mr. Chairman.

EXAMINATION

BY COMMISSIONER WHITFIELD:

Q Good afternoon. Good to have you with us today.

A *[DAVIS]* Good afternoon.

Q On pages six and eight of your surrebuttal testimony and again in your summary, you clarify that SACE recommends the Commission direct Duke to solicit bids for 375 megawatts of solar capacity in addition to the 750-megawatt combined-cycle facility that is the subject of this proceeding. Is it reasonable regulatory policy for this Commission to direct Duke or any other utility to

pursue generation capacity beyond its needs, as identified in their IRPs?

A *[DAVIS]* Well, I mean, I think the idea is that this solar, or up to 375 megawatts of additional solar, can be a companion piece to this plant. So it's not a capacity need; it's an offset of costs associated with running Lee. So if a bidder came in and proposed a project that you could site, or multiple projects that you could site and complement this Lee Plant, what you're doing is reducing the need to run Lee. So it's not actually anticipated to be a capacity increase; it's complementary capacity that would offset some of the operations of Lee and also potentially some of its costs.

Q I think you said in your summary that you'd continue to operate the gas plant as long as the bid is under, but who would pay for this excess capacity in what you're recommending?

A *[DAVIS]* Well, so, Duke would pay for it, but what we are envisioning is that they would establish a benchmark price where it would be cheaper to enter into this contract for this solar capacity than it would be to run the natural gas plant. So what you're doing is trading -- you are ramping down, you know, some percentage of the operations at the plant, replacing that with the

solar. If that is not a wash or a net benefit to ratepayers, then Duke wouldn't move forward with that proposal. It would be triggered if the costs were neutral to ratepayers or a reduction in costs to ratepayers, so there's no risk on the front end, or back end, of this as we have proposed it.

COMMISSIONER WHITFIELD: Thank you, Mr. Chairman. That's all I have.

CHAIRMAN HAMILTON: Okay. Any others -- Commissioner Hall? I'm sorry. Any other questions?

[No response]

Thank you, very much, gentlemen. You may be excused -- did you have any redirect[sic]?

MS. SHAFEEK-HORTON: No, sir.

CHAIRMAN HAMILTON: Thank you.

[WHEREUPON, the witnesses were excused.]

CHAIRMAN HAMILTON: Okay. I believe, Mr. Holman -- are we going to have a panel for ORS?

MS. HUDSON: We have just one witness for ORS, today.

CHAIRMAN HAMILTON: Just one witness, okay.

MS. HUDSON: So we'll make that -- we'll have a panel of one.

[Laughter]

CHAIRMAN HAMILTON: A panel of one. Okay, very good. Well, he can take the panel's spot up here, then.

MS. HUDSON: ORS calls Mr. Gene Soult to the stand.

[Witness sworn]

THEREUPON came,

G E N E G . S O U L T ,

called as a witness on behalf of the South Carolina Office of Regulatory Staff, who, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. HUDSON:

Q Good afternoon, Mr. Soult. Would you please state your name and business address?

A Yes, ma'am. My name is Gene Soult. Our business address is 1401 Main Street in Columbia, South Carolina?

Q What is your occupation with ORS?

A I am the senior research analyst for the Electrical Department, ma'am.

Q Did you cause six pages of direct testimony to be filed with the Commission on December 10, 2013?

A I did.

Q Do you have any changes, additions, or deletions to that testimony?

A I do not.
Q Would your answers remain the same if you were asked those questions today?
A Yes, ma'am.

MS. HUDSON: Mr. Chairman, we ask that Mr. Soult's testimony be entered into the record and treated as if read orally from the stand.

CHAIRMAN HAMILTON: Mr. Soult's testimony will be entered into the record as if given orally from the stand.

[See pgs 211-217]

MS. HUDSON: Thank you.

BY MS. HUDSON:

Q Mr. Soult, could you provide a summary of your testimony to the Commission?
A Yes, ma'am. My name is Gene Soult. I work with the Office of Regulatory Staff. I joined the staff in May of 2010. I've worked the bulk of my career in the energy field. The purpose of my testimony is to provide the results of ORS' review for the Joint Application in this matter.

ORS reviewed the Joint Application and all supporting documentation, and determined that the Application met the requirements of the regulations. ORS also reviewed the company's Lee Project Study; it

was submitted on October the -- 2013. The study provided additional information about the Lee site, the existing environmental and physical conditions of the site, the impact of installing the Lee Combined-Cycle Project on the plant and the environment.

ORS also reviewed the company's testimony and determined the need for substantial base and intermediate generation in the timeframe of 2017-2018. ORS traveled to the Lee Steam Station and met with company representatives that were knowledgeable about the plant site and had previous experience in building the combined-cycle natural-gas facility like is projected there on brown-field site. And ORS reviewed additional information provided by the company pertaining to the selection process, to determine the cost-effectiveness of the Lee self-build option.

In summary, ORS concluded that the Application meets the requirements of the Siting Act. The company's testimony provides evidence of the need for the capacity in Year 2017-2018 timeframe. The company's plan to utilize the existing Lee Steam Station as the site for the combined-cycle project allows them to minimize their capital costs, provide a boost to the local economy, strengthen and extend the life of the existing plant, and the new plant should provide jobs for the local area

and be efficient and reliable electric generation at a competitive price for our South Carolina customers.

That concludes my summary.

CHAIRMAN HAMILTON: Thank you, sir.

MS. HUDSON: Thank you, Mr. Soult.

[PURSUANT TO STIPULATION AND PREVIOUS INSTRUCTION, THE PREFILED DIRECT TESTIMONY OF GENE G. SOULT FOLLOWS AT PGS 211-217]

THE OFFICE OF REGULATORY STAFF

DIRECT TESTIMONY OF

GENE G. SOULT

DECEMBER 10, 2013

DOCKET NO. 2013-392-E

Joint Application of Duke Energy Carolinas, LLC and North Carolina Electric Membership Corporation for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of a 750 MW Combined Generating Plant Near Anderson, SC

DIRECT TESTIMONY OF

GENE G. SOULT

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2013-392-E

IN RE: Joint Application of Duke Energy Carolinas, LLC and North Carolina Electric Membership Corporation for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of a 750 MW Combined Generating Plant Near Anderson, SC

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Gene G. Soult. My business address is 1401 Main Street, Suite 900, Columbia, South Carolina 29201. I am employed by the State of South Carolina as a Senior Research Analyst in the Electric Department for the South Carolina Office of Regulatory Staff ("ORS").

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I received my Bachelor's Degree from Troy State University located in Dothan, Alabama in 1986. I also received a Master's Degree in Business Administration from Webster University in 2000. I joined ORS in May of 2010. I have been directly involved in the electric utility industry for over 30 years. My experience incorporates a variety of supervisory and management responsibilities and consulting related to all aspects of nuclear, hydro, and fossil generation.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide the Public Service Commission of South Carolina ("Commission") the results of ORS's review of the Joint Application of

Duke Energy Carolinas, LLC ("Company") and North Carolina Electric Membership Corporation ("NCEMC") for a Certificate to construct and operate a 750 Megawatt ("MW") Combined Cycle Generating Plant adjacent to the Company's existing Lee Steam Station, near Anderson, South Carolina ("Joint Application"). The Joint Application was filed pursuant to the Utility Facility Siting and Environmental Protection Act ("Siting Act") and Commission Regulation 103-304.

Q. PLEASE DISCUSS ORS'S REVIEW OF THE JOINT APPLICATION.

A. ORS reviewed the Joint Application, which included copies of the required notifications, direct testimonies of NCEMC witness Michael W. Burnette, Company witnesses Clark S. Gillespy, Janice D. Hager, and Mark E. Landseidel. Included in witness Hager's direct testimony is the Company's 2013 Integrated Resource Plan ("IRP"). ORS reviewed the Lee Combined Cycle Project ("LCCP") study that was filed by the Company in October 2013. ORS reviewed additional materials provided by the Company through discovery and conducted discussions with Company representatives. ORS also conducted a tour of the proposed site to visualize the impact of the new facility on the existing facility and surrounding area.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE PROPOSED LCCP FACILITIES.

A. The Company's LCCP study describes the existing Lee Steam Station site, surrounding area and the proposed new generation facility. The existing site is located on State Road S-4-178, approximately three (3) miles southeast of the center of downtown Williamston, South Carolina. Lee coal-fired Steam Station began commercial operation in 1951 and occupies approximately 689 acres of land, most of which exists in Anderson

County. The Company's 2013 IRP addresses the need to retire the existing Lee Steam coal-fired Units 1 and 2 on or before April 15, 2015, and convert Unit 3 to run on natural gas. With the retirements of Units 1 and 2, and the conversion of Unit 3 to natural gas, the Lee station site offers the Company an opportunity to capitalize on existing land, water, natural gas, and transmission resources to install a natural gas powered 750 MW generation facility to meet a capacity need in the 2017-2018 timeframe. The power block will consist of two (2) combustion turbines, one (1) steam turbine, and three (3) electric generators arranged in a two-on-one configuration. The electrical output will be connected through a new 100 Kilovolt (kV) switchyard located within the existing property boundary.

Q. PLEASE DESCRIBE THE INFORMATION REQUIRED BY THE SITING ACT TO BE INCLUDED IN AN APPLICATION FOR A CERTIFICATE.

A. The Siting Act directs that an application contain a description of the location and the major utility facility(ies) to be built; a summary of any studies which have been made of the environmental impact of the facility(ies); a statement explaining the need for the facility(ies); and such other information as the applicant may consider relevant or as the Commission may require.

Q. DOES THE JOINT APPLICATION CONTAIN THIS INFORMATION?

A. Yes. The Joint Application and supporting testimony submitted under Docket No. 2013-392-E addresses the regulatory reporting requirements. Additional information is also provided in the Company's LCCP study.

Q. WHAT IS ORS'S UNDERSTANDING OF THE BASIS OF THE NEED FOR THIS FACILITY?

A. The Company's 2012 IRP initially established a need for a new combined cycle facility to be online in time to meet the summer 2016 peak demand. Based on this capacity need, the Company initiated a Request for Proposal ("RFP") in October 2012 for 700 MW of dependable capacity to be available for the summer peak of 2016. During the 2013 IRP review, the Company determined that the capacity need for 2016 could be met with an additional 36 MW of capacity, while maintaining a lower 14.5% Reserve Margin. The 2013 IRP also identified the environmental and economic need to retire the older, less efficient Lee Station 1 and 2 coal-fired units. Witness Gillespy's direct testimony (pages 4 and 5) describes the Company's decision making process for pursuing the 750 MW intermediate and baseload generation to meet resource needs in the 2017-2018 timeframe.

Q. WHAT IS THE PROBABLE ENVIRONMENTAL IMPACT OF THE FACILITY?

A. Section 2 of the Company's LCCP study provides a site analysis that addresses Cultural Resources, Visual and Auditory Resources, Geology and Seismology, Climate and Air Quality considerations, Water Quality, Terrestrial and Aquatic resources, Waste Disposal and Fuel Handling, and Population and Demographics. Page 10 concludes that, "the proposed LCCP will have minimal effects on the visual resources and scenic quality of the area surrounding the proposed site." Page 49 addresses solid waste disposal cleanup from the construction of the LCCP.

Section 6 of the LCCP study describes the air and water quality standards that the new LCCP must meet. The retirement of the existing coal-fired units will have a net

positive effect on the site. Page 2 describes the United States Environmental Protection Agency standards that will be met by the new plant. Page 3 describes the positive impact that the new plant will have on water quality discharge. The overall environmental impact of the changes to the Lee Steam Station, including the addition of the LCCP, is expected to be positive.

Q. HOW WILL THE NEW LCCP SERVE THE INTEREST OF SYSTEM ECONOMY AND RELIABILITY?

A. The addition of the LCCP is expected to improve the local area economy. Page 6 of witness Gillespy's direct testimony describes the Company's long-term investment to the energy infrastructure in South Carolina, and purports that "at the height of the two (2) year-long construction period, there will be approximately 500 jobs on site. Once the project is complete, we anticipate adding approximately 25 full-time jobs for highly skilled employees who will be well-paid."

The purpose statement of the Company's LCCP study indicates that the Company is expecting the LCCP to generate base or intermediate load at an expected capacity of 50% to 75% for a period of 20 to 30 years. Appendix B provides an overview of the plant systems and components. The proposed power block is a proven design that is already in use in the Company's system. These existing units have demonstrated high capacity factors and availability factors, which provides a good indication of the reliability of the LCCP when properly operated and maintained.

Q. PLEASE DESCRIBE THE OWNERSHIP OF THE NEW FACILITY.

A. The Joint Application establishes that the Company will own 650 MW (86.67%) of the LCCP. NCEMC will be a minority partner, and will own 100 MW (13.33%) of the

LCCP. The Joint Application includes the direct testimony of witness Burnette, Sr. Vice President, Chief Operating Officer of NCEMC. Page 4 of witness Burnette's testimony provides NCEMC's reasoning for pursuing a joint ownership in the LCCP. Witness Burnette discusses NCEMC's desire to secure additional resources to serve the existing and future loads as well as to enhance NCEMC's power supply portfolio. Company witness Gillespy further explains on page 5 of his direct testimony how the NCEMC joint ownership supports the Company's 2013 IRP.

Q. IS JOINT OWNERSHIP OF THE LCCP NECESSARY?

A. No. Witness Hager's direct testimony describes the Company's process used to evaluate the RFP responses and the 2013 RFP refreshed requests, which included the self-build option. Page 21 explains that the final cost analysis indicated that the "self-build" option of the LCCP was the least cost option, with or without joint ownership. Additionally, Exhibit Hagar 7 shows that joint ownership of the LCCP between the Company and NCEMC is the least cost option.

Q. WILL PUBLIC CONVENIENCE AND NECESSITY BE SERVED BY THE LCCP?

A. Yes. ORS's review of the information provided in the Joint Application indicates that the Company intends to build an efficient and reliable plant that will be economical and minimize the environmental impact, while strengthening the reliability of electric generation and the transmission grid.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

MS. HUDSON: Mr. Soult is available for questions from the Intervenors and the Commission. Thank you.

CHAIRMAN HAMILTON: Thank you.

Ms. Thompson, Mr. Holman, questions?

MS. THOMPSON: No --

MR. HOLMAN: No questions.

MS. THOMPSON: -- questions, Mr. Chairman.

CHAIRMAN HAMILTON: Commissioners? Commissioner Fleming?

COMMISSIONER FLEMING: Thank you.

EXAMINATION

BY COMMISSIONER FLEMING:

Q Good afternoon.

A Good afternoon.

Q I wish I'd asked this question to the panel before, but you heard the testimony of Mr. Davis and Mr. Wilson.

A I did.

Q And when you were looking at this project, are there other projects that have been built similar to what they propose to do?

A Yes, ma'am -- other projects as what Wilson and them have described?

Q Uh-huh.

A Not to my knowledge, dealing with the solar and the

combined-cycle project -- is that what you're asking?

Q Yes, I am.

A I do not know of one, ma'am.

COMMISSIONER FLEMING: Okay, thank you.

CHAIRMAN HAMILTON: Okay. Commissioners, any other questions?

[No response]

MR. HOLMAN: Mr. Chairman, I don't know if it would be appropriate to make our panel available for any follow-up questions, or to submit supplemental information?

CHAIRMAN HAMILTON: ORS, did you have any redirect?

MS. HUDSON: No redirect.

CHAIRMAN HAMILTON: Do you have any objection to Mr. Holman's --

MS. HUDSON: Not at all.

MS. SHAFEEK-HORTON: No, sir.

CHAIRMAN HAMILTON: Okay, Mr. Holman?

MR. HOLMAN: Okay. Sorry, so we can bring up our panel to answer Commissioner Fleming's question? I was just offering to make them available -- I didn't know what the procedure is, but -- to answer Commissioner Fleming's question.

CHAIRMAN HAMILTON: Okay. That would not be

available or necessary.

Okay. Hearing no other questions, you may be excused, Mr. Soult.

WITNESS: Thank you.

[WHEREUPON, the witness was excused.]

CHAIRMAN HAMILTON: Do we have any other matters to come before the Commission at this time? Any closing statements?

MS. SHAFEEK-HORTON: No, sir.

MR. HOLMAN: Nothing from the Intervenors.

MS. HUDSON: And nothing from ORS.

CHAIRMAN HAMILTON: Okay. With that, we'll bring the time to the proposed orders. Would March 3rd be a convenient date for that?

MS. HUDSON: That works for ORS.

MS. SHAFEEK-HORTON: Yes, sir.

CHAIRMAN HAMILTON: Fine. All right. Proposed orders for the third. We appreciate all of you being here today, and this hearing was adjourned. Thank you, very much.

[Witnesses previously excused]

[WHEREUPON, the hearing in the above-entitled matter was adjourned at 1:45 p.m.]

[WHEREUPON, Late-Filed Hearing Exhibit 3 shall be marked and received in evidence upon receipt of same: 2/11/14]

[WHEREUPON, Late-Filed Hearing Exhibit 7 was marked and received in evidence upon receipt of same: 2/7/14]

C E R T I F I C A T E

I, Jo Elizabeth M. Wheat, CVR-CM-GNSC, Notary Public in and for the State of South Carolina, do hereby certify that the foregoing is, to the best of my skill and ability, a true and correct transcript of all the proceedings had in a hearing [Volume 2] held in the above-captioned matter before the PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA;

That the witnesses appearing during said hearing were sworn or affirmed by me to state the truth, the whole truth, and nothing but the truth;

IN WITNESS WHEREOF, I have hereunto set my hand and seal, on this the 22nd day of February, 2014.

Jo Elizabeth M. Wheat, CVR-CM/M-GNSC
Hearings Reporter, PSC/SC
My Commission Expires: January 27, 2021.

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ABBREVIATIONS	
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CC	Combined Cycle
CCR	Coal Combustion Residuals
CECPCN	Certificate of Environmental Compatibility and Public Convenience and Necessity
CFL	Compact Fluorescent Light bulbs
CO_2	Carbon Dioxide
COD	Commercial Operation Date
COL	Combined Construction and Operating License
COWICS	Carolinas Offshore Wind Integration Case Study
CPCN	Certificate of Public Convenience and Necessity
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
DC	Direct Current
DEC	Duke Energy Carolinas
DEP	Duke Energy Progress
DOE	Department of Energy
DSM	Demand Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FLG	Federal Loan Guarantee
GHG	Greenhouse Gas
HVAC	Heating, Ventilation and Air Conditioning
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Plan
IS	Interruptible Service
JDA	Joint Dispatch Agreement
LCR Table	Load, Capacity, and Reserve Margin Table
LEED	Leadership in Energy and Environmental Design
MACT	Maximum Achievable Control Technology
MATS	Mercury Air Toxics Standard
NAAQS	National Ambient Air Quality Standards
NC	North Carolina
NCDAQ	North Carolina Division of Air Quality
NCEMC	North Carolina Electric Membership Corporation
NCMPA1	North Carolina Municipal Power Agency #1
NCUC	North Carolina Utilities Commission

ABBREVIATIONS CONT.	
NERC	North American Electric Reliability Corp
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standard
PD	Power Delivery
PEV	Plug-In Electric Vehicles
PMPA	Piedmont Municipal Power Agency
PPA	Purchase Power Agreement
PPB	Parts Per Billion
PSD	Prevention of Significant Deterioration
PV	Photovoltaic
PVDG	Solar Photovoltaic Distributed Generation Program
PVRR	Present Value Revenue Requirements
QF	Qualifying Facility
RCRA	Resource Conservation Recovery Act
REC	Renewable Energy Certificates
REPS	Renewable Energy and Energy Efficiency Portfolio Standard
RFP	Request for Proposal
RIM	Rate Impact Measure
RPS	Renewable Portfolio Standard
SC	South Carolina
SCPSC	South Carolina Public Service Commission
SCR	Selective Catalytic Reduction
SEPA	Southeastern Power Administration
SERC	SERC Reliability Corporation
SG	Standby Generation
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TAG	Technology Assessment Guide
TRC	Total Resource Cost
The Company	Duke Energy Carolinas
The Plan	Duke Energy Carolinas Annual Plan
UCT	Utility Cost Test
VACAR	Virginia/Carolinas
VAR	Volt Ampere Reactive

1. EXECUTIVE SUMMARY

Each year Duke Energy Carolinas (DEC or the Company) is required by both the North Carolina Utilities Commission (NCUC) and the South Carolina Public Service Commission (SCPSC) to submit a planning document to ensure that it can reliably and affordably meet the energy needs of its customers well into the future.

This year, in addition to providing a traditional standalone Base Case resource plan within the 2013 Integrated Resource Plan (IRP) Update, the Company has also developed an alternative Joint Planning Scenario that examines the benefits of a coordinated energy and capacity expansion plan with Duke Energy Progress (DEP).

DEC does not currently have the regulatory approvals required to implement this joint plan, however this scenario simply begins to examine the potential benefits that would accrue to customers once DEC and DEP coordinate new resource additions between the companies. Any benefits that would accrue from new jointly planned resources would be in addition to the current merger savings already being realized through the Joint Dispatch Agreement (JDA) and fuel procurement activities associated with existing generation resources.

Increased Energy Efficiency/Demand Side Management

Duke Energy continues to expand its portfolio of energy efficiency products and services – offering customers more ways to take control of their energy usage and save money.

DEC's Energy Efficiency (EE) programs encourage customers to save electricity by installing high-efficiency measures and/or changing the way they use their electricity.

DEC also offers a variety of Demand Side Management (DSM) programs that signal customers to reduce electricity use during select peak hours as specified by the Company.

- Energy Efficiency programs and Demand Side Management, combined with the use of renewable energy resources are expected to meet approximately one third of the projected growth in customer demand over the next 15 years. This equates to over 2,400 MW of new energy efficiency, demand side management and renewable resources or the equivalent of three large natural gas-generation facilities.

- Aggressive marketing and increased adoption of energy efficiency programs reduce the annual forecast demand growth from 1.9 to 1.5%.

- DEC will continue to seek Commission approval to implement new DSM and EE programs that are cost effective and consistent with DEC's forecasted resource needs over the planning horizon.

Growth of Renewable Energy and Solar Resources

The Company continues to purchase renewable energy on behalf of our customers and make investments that support our delivery of clean, reliable and affordable electricity.

DEC's strategy to comply with the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS) is to develop a diverse portfolio of cost-effective renewable resources including long-term Purchase Power Agreements (PPAs), utility-owned generation, and energy efficiency.

DEC is committed to meeting the requirements established under the NC REPS and to procuring renewable energy in a way that minimizes costs for customers. The Company remains on target to meet these standards within the cost caps established under NC REPS. The Base Case also assumes the addition of future S.C. renewable resources that could be driven by regulatory mandates or market-based forces.

Solar energy is an important part of the energy future for the Carolinas. As the net price of solar technologies including tax incentives continues to decrease, customer use of solar continues to increase.

- The growth of solar energy has been spurred by several factors, including state and federal subsidies that are expected to be in place through 2015 and 2017, respectively.

- Substantial tax subsidies and declining costs make solar energy the Company's primary renewable resource projected within the NC REPS compliance plan.

- The Company's plan currently projects that by the end of the planning horizon, the Company will have met over 700 MW of peak demand through solar resources - the equivalent of one large natural gas facility.

Retiring Older, Less Efficient Coal Units

Duke Energy Carolinas is investing in a brighter energy future for its more than 2.4 million customers in North and South Carolina. The Company has built some of the cleanest, most efficient natural gas plants to replace aging, less efficient generation facilities in order to provide essential

power to the communities that DEC serves. This advanced generation technology helps the Company comply with more stringent air, water and waste rules.

- Since 2011, DEC has retired 15 coal units, totaling 1,300 MW, in addition to 400 MW of older oil units.

- In April 2015, the last of DEC's coal stations that lack advanced emission controls is scheduled to be retired. Lee Steam Station Units 1 and 2, located in Pelzer, S.C. are currently planned for retirement to correspond with the effective date of the federal Mercury Air Toxics Standard (MATS) while Unit 3 is scheduled to be repowered to run on natural gas.

- In December 2012, following the retirement of the Dan River coal units, the Dan River Combined Cycle (CC) facility became operational. This 620 MW natural gas-fired CC generating station located in Eden, N.C. achieves high operational flexibility and high thermal efficiency, while utilizing advanced environmental control technology to minimize plant emissions.

- The 825 MW Cliffside Steam Station Unit 6 in Mooresboro, N.C., which was completed at the end of 2012 is one of the cleanest coal units in the United States and has advanced emission controls that remove more than 99% of sulfur dioxide and 90% of nitrogen and mercury.

Improved Emissions

The combination of investments in advanced emission controls, retirements of older units and the addition of efficient clean natural gas units has culminated in dramatic reductions in power plant emissions over the last decade.

- Projected SO_2 emission levels in 2014 are expected to be 96% less than they were a decade earlier in 2005.

- Projected NO_x emission levels in 2014 are expected to be 76% less than they were in 2005.

This positions Duke Energy Carolinas as an industry leader in emission reductions. DEC is currently on track to exceed pending federal air emission standards.

Natural Gas: Meeting Future Customer Demand

Modernizing the power plant fleet is an important investment in the Carolinas' environment and its future. Because the Company continues to retire older, less efficient coal plants, new incremental resources must be added to the DEC system. New resources are also required to keep up with increasing customer demand.

After accounting for the previously-discussed impacts of DEC's EE, DSM and renewable resources, the Company projects it will meet its customers' remaining requirements with a combination of natural gas and nuclear resources.

The 2013 IRP identifies the need for new natural gas plants that are economic, highly efficient and reliable. The following natural gas resources are included in the plan for the 2014 through 2028 planning horizon:

- **2015** – Convert a 170 MW coal unit to natural gas at the Lee Steam Station in S.C.
- **2017** – Construct a new 680 MW natural gas CC generation facility
- **2019** – Procure or construct 843 MW of natural gas CC generation
- **2022** – Procure or construct 403 MW of simple cycle combustion turbines (CTs)

Nuclear Generation

Duke Energy Carolinas believes nuclear generation is important for the long-term benefits of its customers – today and in the future. The 2013 IRP continues to support new nuclear generation as a carbon-free, cost-effective option within the Company's resource portfolio.

- W.S. Lee Nuclear Station, Cherokee, S.C. - DEC continues to pursue nuclear expansion options at the proposed site. Currently a new and updated site-specific seismic analysis is being conducted at the request of the Nuclear Regulatory Commission. Completion of this report delays licensing and pushes the project completion date to 2024.

- V.C. Summer Nuclear Plant, Fairfield, S.C. - Discussions also continue with Santee Cooper to possibly purchase an interest in two units under construction at the V.C. Summer Nuclear Plant in Fairfield County, S.C. in the 2018 through 2020 timeframe.

The table below illustrates the Company's optimal Base Case resource plan that includes the gas and nuclear additions described above. As discussed, in addition to these traditional resources, the Base Case also includes approximately 2,400 MW of EE, DSM and renewable resources.

Table 1-A DEC Base Case

Duke Energy Carolinas Resource Plan Base Case		
Year	Resource	MW
2014	Nuclear Uprates	20
2015	Lee 5 NG Conversion	170
	Nuclear Uprates	32
2016	-	-
2017	New CC	680
	Nuclear Uprates	45
2018	VC Summer Nuclear	66
2019	New CC	843
2020	VC Summer Nuclear	66
2021	-	-
2022	New CT	403
2023	-	-
2024	New Nuclear	1117
2025	-	-
2026	New Nuclear	1117
2027	-	-
2028	-	-

Note: Table includes both designated and undesignated capacity additions

One Company: The Benefits of Shared Capacity

DEC also examines a Joint Planning Scenario which shows the impact of capacity sharing between DEC and DEP. This exercise starts by combining the future load obligations of the two companies and combining the existing and projected resources from both DEC's and DEP's independent Base Case plans. However, rather than maintaining utility-specific individual minimum reserve margins, the Joint Planning Scenario simply ensures that the combined system maintains adequate reserves when viewed in the aggregate.

The sharing of capacity between the systems defers the need for new additions of generation. If DEC and DEP receive the appropriate regulatory approvals to allow for the sharing of resources, the Joint Planning Scenario illustrates how benefits would accrue to both companies' customers by delaying investment in new generation.

Federal Regulations and Future Market Conditions

With the information and data currently available, the 2013 IRP is a best projection of what the Company's energy portfolio will look like 15 years from now. This projection can change and will change depending on changing load forecasts, energy prices, new environmental regulations and other outside factors.

Environmental Focus Scenario

What if there is an aggressive new carbon tax in 10 years? Or additional new government mandates are required of electric utilities? The Company has created an Environmental Focus Scenario that factors in significant increases in EE and renewable resources that would influence the plan if regulatory, legislative, or market conditions changed from today's base assumptions to support such increases. This scenario examines how the amount of traditional supply-side resources would change if future market conditions and/or state and federal regulations resulted in higher levels of energy efficiency and renewable resources.

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The following chapters give an overview of the inputs incorporated into the 2013 IRP. Chapter 8 provides insight into the planning process itself and reviews the results of the Base Case resource plan as well as the two alternative scenarios developed in this planning cycle. Finally, the appendices to this document give even greater detail and specifics regarding the input development and analytic process that produced the resource plans contained in this year's IRP filing.

2. SYSTEM OVERVIEW

DEC 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, the Company 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 Appendix C.

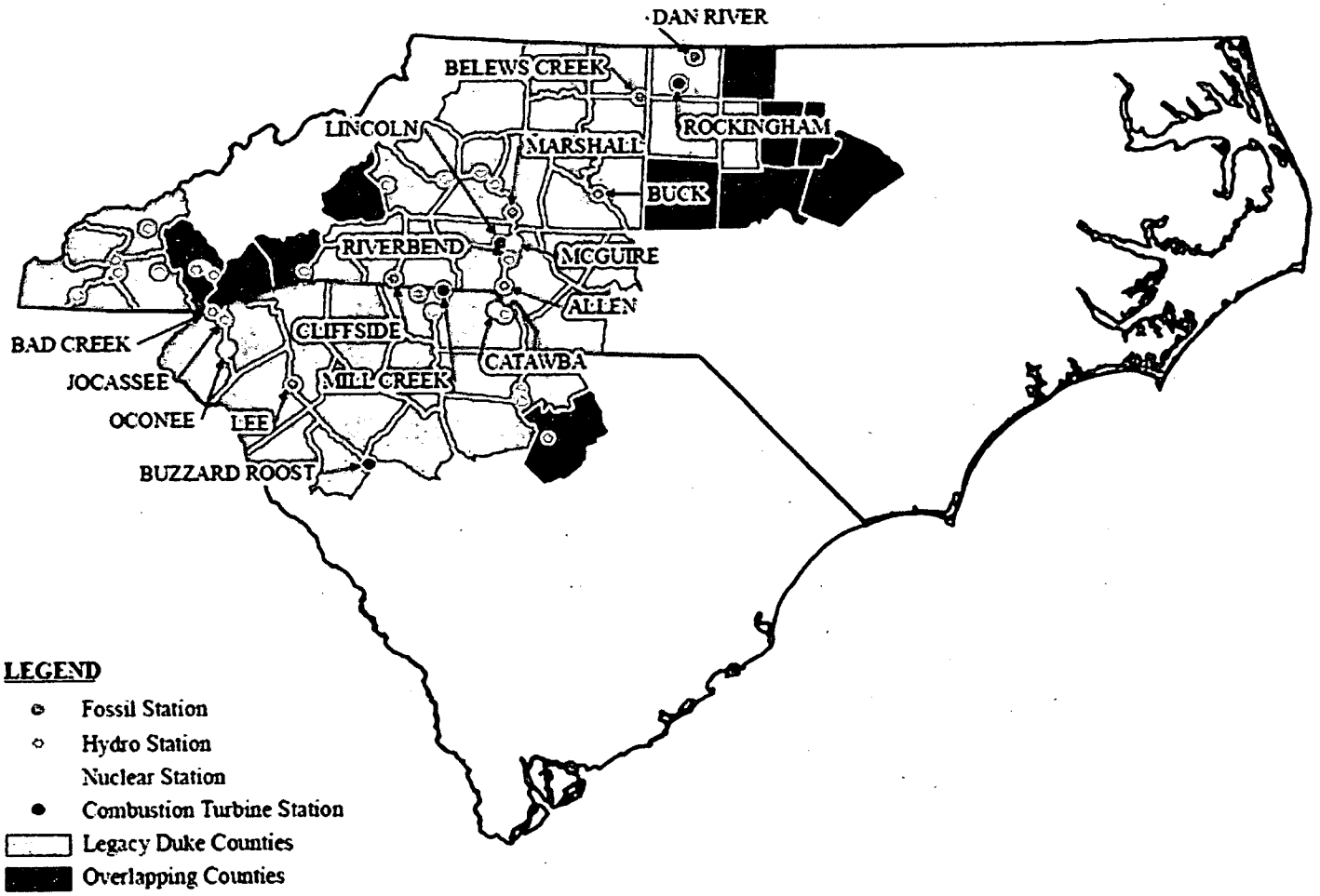
DEC currently meets energy demand, in part, by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:

- Three nuclear generating stations with a combined capacity of 7,054 MW
- Five coal-fired stations with a combined capacity of 7,172 MW
- 29 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 3,229 MW
- Six CT stations and two CC stations with a combined capacity of 4,010 MW

The Company's power delivery system consists of approximately 101,700 miles of distribution lines and 13,100 miles of transmission lines. The transmission system is directly connected to all of the utilities that surround the DEC service area. There are 36 circuits connecting with nine different utilities: DEP, American Electric Power, Tennessee Valley Authority, Smokey Mountain Transmission, Southern Company, Yadkin, Southeastern Power Administration (SEPA), South Carolina Electric & Gas (SCE&G) 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) sub-region, SERC Reliability Corporation (SERC) (formerly Southeastern Electric Reliability Council) and North American Electric Reliability Corporation (NERC).

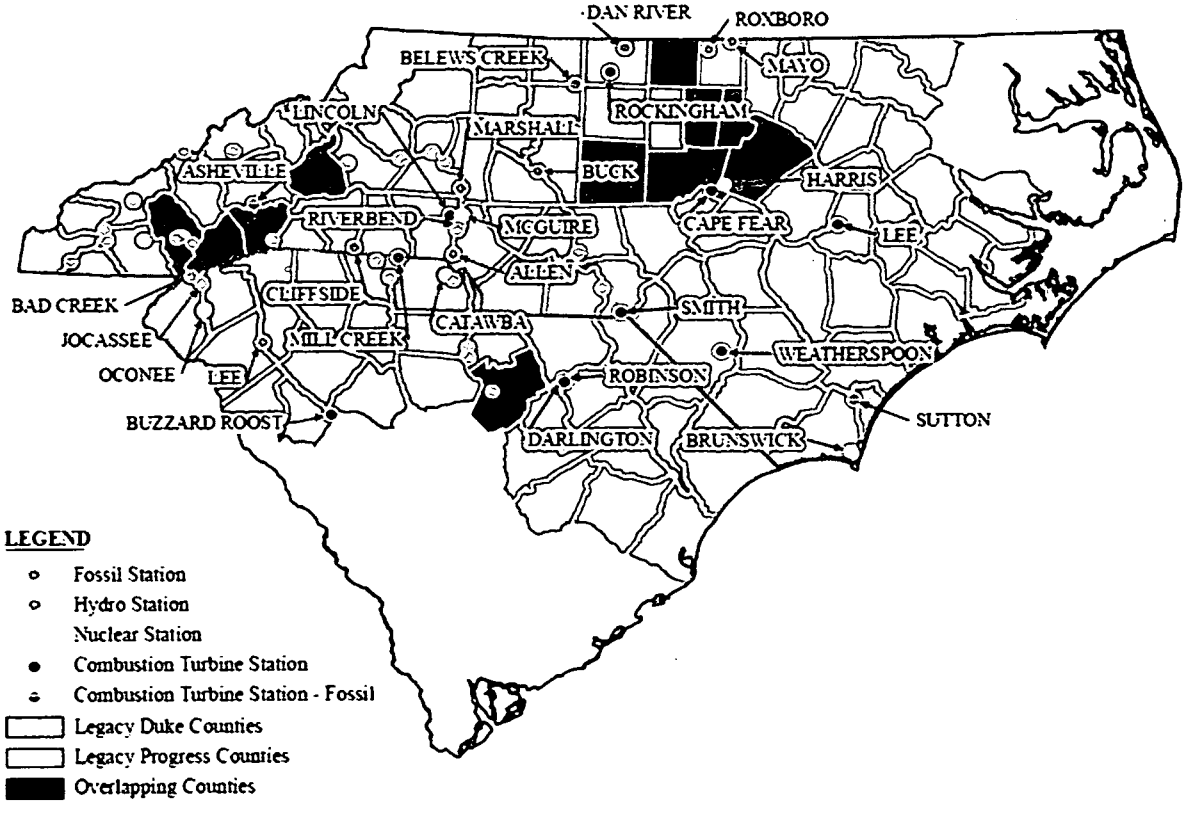
The map on the following page provides a high-level view of the DEC service area.

Chart 2-A Duke Energy Carolinas Service Area



With the closing of the Duke Energy Corporation and Progress Energy Corporation merger, the service territories for both DEC and DEP lend to future opportunities for collaboration and potential sharing of capacity to create additional savings for North Carolina and South Carolina customers of both utilities. An illustration of the service territory of the Companies is shown in the map below.

Chart 2-B DEC and DEP Service Area



3. ELECTRIC LOAD FORECAST

The Duke Energy Carolinas' spring 2013 forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2014 through 2028 and represents the needs of the retail classes and the wholesale buyers with whom DEC has a contractual obligation to serve.

Long-term electricity usage is determined by economic and demographic trends. The 2013 spring forecast was developed using industry-standard linear regression techniques, which relate electricity usage to such variables as income, electricity prices and the industrial production index along with weather and population. DEC has used regression analysis since 1979 and this technique has yielded consistently reasonable results over the years.

The economic projections used in the spring 2013 forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of North Carolina and South Carolina.

The retail forecast consists of the three major classes: residential, commercial and industrial.

The residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electricity price and appliance efficiencies. The usage per customer forecast is essentially flat through much of the forecast horizon, so most growth is primarily due to customer increases. The projected growth rate of residential sales in the spring 2013 forecast from 2014-2028 is 1.2% annually.

Commercial electricity usage changes with the level of regional economic activity, such as personal income or commercial employment, and the impact of weather. The three largest sectors in the commercial class are offices, education and retail. Commercial is expected to be the fastest growing class, with a projected sales growth rate of 1.8%.

The industrial class forecast is impacted by the level of manufacturing output, exchange rates, electric prices and weather. The long-term structural decline that has occurred in the textile industry is expected to moderate in the forecast horizon, with an overall projected sales decline of 1.2%, compared to an average decline of 7.2% from 1997-2012. In the other industrial sector, several industries such as autos, rubber and plastics and primary metals, are projected to show strong growth. Overall, other industrial sales are expected to grow 0.9% over the forecast horizon. Including all industrial classes, the overall sales growth rate of the total industrial class is 0.6% over the forecast horizon.

Including the impacts of DEC's EE programs, the projected average annual growth rate from 2014 through 2028 is 1.5% for summer peak, 1.5% for winter peak and 1.5% for energy. These growth rates represent a 4,164 MW increase in capacity and 20,826 MWh increase in energy by 2028.

Compared to the spring 2012 forecast, the spring 2013 forecast reflects lower growth, due to a slightly slower economic outlook. For example, the growth rate of the summer peak after all adjustments in the spring 2012 forecast is 1.7% versus 1.5% in the new forecast.

The load forecast projection for energy and capacity including the impacts of EE that was utilized in the 2013 IRP is shown in Table 3-A.

Table 3-A Load Forecast with Energy Efficiency Programs

YEAR	SUMMER (MW)	ENERGY (GWh)
2014	18,332	92,943
2015	18,691	94,721
2016	19,053	96,475
2017	19,398	98,226
2018	19,741	100,032
2019	20,117	101,678
2020	20,359	102,948
2021	20,598	104,187
2022	20,848	105,469
2023	21,104	106,748
2024	21,378	108,089
2025	21,643	109,418
2026	21,922	110,825
2027	22,209	112,294
2028	22,496	113,769

Note: Table 8-C differs from these values due to a 150 MW firm sale in 2014 and a 47 MW Piedmont Municipal Power Agency (PMPA) backstand contract through 2020.

A detailed discussion of the electric load forecast is provided in Appendix C.

4. ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT

DEC is committed to making sure electricity remains available, reliable and affordable and that it is produced in an environmentally sound manner and, therefore, advocates a balanced solution to meeting future energy needs in the Carolinas. That balance includes a strong commitment to demand side management and energy efficiency.

Since 2009, DEC has been actively developing and implementing new DSM and EE programs throughout its North Carolina and South Carolina service areas to help customers reduce their electricity demands. DEC's DSM and EE plan was designed to be flexible, with programs being evaluated on an ongoing basis so that program refinements and budget adjustments can be made in a timely fashion to maximize benefits and cost-effectiveness. Initiatives are aimed at helping all customer classes and market segments use energy more wisely. The potential for new technologies and new delivery options is also reviewed on an ongoing basis in order to provide customers with access to a comprehensive and current portfolio of programs.

DEC's EE programs encourage customers to save electricity by installing high efficiency measures and/or changing the way they use their existing electrical equipment. DEC evaluates the cost-effectiveness of DSM/EE programs from the perspective of program participants, non-participants, all customers as a whole and total utility spending using the four California Standard Practice tests (i.e., Participant Test, Rate Impact Measure (RIM) Test, Total Resource Cost (TRC) Test and Utility Cost Test (UCT), respectively) to ensure the programs can be provided at a lower cost than building supply-side alternatives. The use of multiple tests can ensure the development of a reasonable set of programs and indicate the likelihood that customers will participate. DEC will continue to seek Commission approval to implement DSM and EE programs that are cost-effective and consistent with DEC's forecasted resource needs over the planning horizon. DEC currently has approval from the NCUC and SCPSC to offer a large variety of EE and DSM programs and measures to help reduce electricity consumption across all types of customers and end-uses.

For IRP purposes, these EE-based demand and energy savings are treated as a reduction to the load forecast, which also serves to reduce the associated need to build new supply-side generation, transmission and distribution facilities. DEC also offers a variety of DSM (or demand response) programs that signal customers to reduce electricity use during select peak hours as specified by the Company. The IRP treats these "dispatchable" types of programs as a resource option that can be dispatched to meet system capacity needs during periods of peak demand.

To better understand the long-term EE savings potential, DEC commissioned an update to the 2011 market potential study performed by Forefront Economics Inc. for the purpose of estimating the achievable potential for EE on an annual basis over a 20-year forecast period. The results of the market potential study are suitable for integrated resource planning purposes and use in long-range

system planning models. However, the study did not attempt to closely forecast short-term EE achievements from year to year. Therefore, the Base Case EE/DSM savings contained in this IRP were projected by blending DEC's five-year program planning forecast into the long-term achievable potential projections from the updated market potential study.

DEC also prepared a high EE savings projection designed to meet the five-year EE performance targets set forth in the December 8, 2011 Settlement Agreement. The savings in this high EE projection are well beyond the levels historically attained by DEC and forecasted in the market potential study. As a result, there is too much uncertainty regarding the possibility of actually realizing this level of EE savings to risk using the high projection in the base assumptions for developing the 2013 integrated resource plan. However, it is being treated as an aspirational target for the development of future EE plans and programs. This level of EE is included as a resource planning sensitivity in the Environmental Focus Scenario.

All of these investments are essential to building customer awareness about EE and, ultimately, reducing energy resource needs by driving large-scale, long-term participation in efficiency programs. Significant and sustained customer participation is critical to the success of DEC's EE and DSM programs. To support this effort, DEC has focused on planning and implementing programs that work well with customer lifestyles, expectations and business needs.

Finally, DEC is setting a conservation example by converting its own buildings and plants, as well as distribution and transmission systems, to new technologies that increase operational efficiency. One example of Duke Energy's dedication to conservation is that the Duke Energy corporate headquarters in Charlotte, N.C., is located in a Leadership in Energy and Environmental Design (LEED) platinum building, the highest LEED rating. LEED is a suite of rating systems for the design, construction, operation and maintenance of green buildings, homes and neighborhoods. Buildings that have attained the LEED platinum certification are among the greenest in the world. See Appendix D for further detail on DEC's DSM, EE and consumer education programs.

5. RENEWABLE ENERGY REQUIREMENTS

DEC's plans regarding renewable energy resources within this IRP are based primarily upon the presence of existing renewable energy requirements and 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 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 EE savings by 2021. NC REPS allows for compliance utilizing not only renewable energy resources supplying bundled energy and renewable energy certificates (RECs) and EE, but also the purchase of unbundled RECs (both in-state and out-of-state) and thermal RECs. Therefore, the actual renewable energy delivered to the DEC system is impacted by the amount of EE, unbundled RECs and thermal RECs utilized for compliance.

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 mandate. 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 many reasonable assumptions could be made regarding such future renewable requirements, the Company has assumed for purposes of the 2013 IRP that a new legislative requirement would be implemented in the future that would result in additional renewable resource development in South Carolina. For planning purposes, DEC has 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 2018 and would gradually increase to a 12.5% level by 2026. Similar to NC REPS, this assumed legislative requirement would incorporate renewable energy and EE, as well as a limited capability to utilize out of state unbundled purchases of RECs. Further, this assumed requirement would not contain additional technology-specific set-asides or a cost-cap feature.

The Company has assessed the current and potential future costs of renewable and traditional technologies. 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, under Base Case assumptions, the IRP modeling does not indicate any material quantity of renewable resource development over and above the required levels.

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 1,364 MW of rated renewable capacity will be interconnected to the DEC system by 2021, with that figure growing to approximately 2,028 MW by the end of the planning horizon in 2028. Actual results could vary substantially depending on future legislative requirements, supportive tax policies, technology cost trends and other market forces.

It should be noted that many renewable technologies are intermittent in nature and that such resources may not be contributing full rated capacity (e.g. nameplate or installed capacity) at the time of peak load. In the 2013 IRP, the contribution to peak values that were utilized were 42% of nameplate for solar and 15% of nameplate for wind resources. The details of the forecasted capacity additions, including both nameplate and contribution to peak are summarized in Table 5-A below.

Table 5-A DEC Base Case Renewables

DEC Renewables								
	MW Contribution to Summer Peak				MW Nameplate			
	Wind	Solar	Biomass/ Hydro	Total	Wind	Solar	Biomass/ Hydro	Total
2014	-	124	62	185	-	294	62	356
2015	-	218	69	287	-	519	69	589
2016	-	239	77	316	-	569	77	646
2017	-	256	84	340	-	609	84	693
2018	-	307	118	425	-	730	118	849
2019	23	355	141	519	150	845	141	1,137
2020	23	402	148	572	150	957	148	1,255
2021	23	442	162	626	150	1,052	162	1,364
2022	23	480	165	668	150	1,142	165	1,458
2023	23	516	180	718	150	1,229	180	1,558
2024	23	550	188	760	150	1,309	188	1,647
2025	23	598	197	818	150	1,424	197	1,771
2026	23	630	195	847	150	1,499	195	1,844
2027	23	653	191	866	150	1,554	191	1,895
2028	23	709	189	921	150	1,689	189	2,028

Summary of Renewable Energy Planning Assumptions

The Company's assumptions relating to renewable energy requirements (existing and anticipated) included in the 2013 IRP are largely similar to the assumptions in DEC's 2012 IRP. However, expectations regarding how those requirements will be met have evolved. Changes from the prior year are summarized below.

As compared to last year's IRP, DEC has assumed the development and interconnection of more solar resources over the planning horizon, along with corresponding reductions in the development of other resources.

The installed cost of solar resources has fallen dramatically over the past few years, driven by increased industry scale, standardization, and technological innovation. Many industry participants expect the cost of solar to continue a steady decline through the end of the decade, albeit at a slower pace than in recent years. Solar resources benefit from generous supportive federal and state policies that are expected to be in place through 2015 or longer. In combination with declining costs, such supportive policies have made solar resources increasingly competitive with other renewable resources, including wind and biomass, at least in the near-term. While uncertainty remains around possible alterations or extensions of policy support, as well as the pace of future cost declines, the Company fully expects solar resources to contribute to DEC's REPS compliance efforts beyond the solar set-aside minimum threshold for NC REPS, and correspondingly in South Carolina.

DEC recognizes that some 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 ultimately be developed in both North and South Carolina. However, land-based wind in the U.S. has benefitted from supportive federal tax policies set to decline in the near future. The Company is a contributor to the U.S Department of Energy (DOE) sponsored Carolinas Offshore Wind Integration Case Study (COWICS). Although the Company expects to rely upon wind resources for REPS compliance, the extent and timing of that reliance will likely vary commensurately with changes to supporting policies and prevailing market prices. 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 expects biomass resources to continue to play an important and vital role in the Company's compliance efforts. However, biomass potential ultimately depends upon how key uncertainties, such as permitting and fuel supply risks, are resolved, as well as the projected availability of other forms of renewable resources to offset the needs for biomass.

Hydro generation remains a valuable and significant part of the generating fleet for the Carolinas. The potential for additional hydro generation on a commercially viable scale is limited and the cost and feasibility are highly site-specific. Given these constraints, hydro is not included in the more detailed evaluations but may be considered when site opportunities are evidenced and the potential is identified. DEC will continue to evaluate hydro opportunities on a case-by-case basis and will include it as a resource option if appropriate.

In general, the Company expects a mix of resources will ultimately be used for meeting renewable targets, with the specifics of that mix determined in large part by policy developments over the coming five to ten years. Costs for all the resources discussed above are highly dependent upon future subsidies, or lack thereof, and the Company's procurement efforts will vary accordingly. Furthermore, the Company values portfolio diversification from a resource perspective, particularly in light of the varying production profiles of the resources in question.

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 is provided as an Attachment to this document.

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.

The Company continues to see an increasing amount of alternative energy resources in the transmission and distribution queues. These resources are mostly solar resources, due to the combination of federal and state subsidies to encourage solar development. This combination of incentives has led solar to be the primary renewable resource projected in the Company's NC REPS Compliance Plan. With state incentives scheduled to end in 2015 and federal incentives scheduled to be reduced in the same time period, the exact amount of solar that will ultimately be developed is highly uncertain. If tax incentives were to be extended or significant additional cost reductions in

the technology realized, incremental solar contribution above NC REPS requirements could be achieved.

The Environmental Focus Scenario evaluates a resource plan under market conditions supportive of higher penetrations of renewable resources and energy efficiency as compared to the Base Case. The Environmental Focus Scenario does not envision a specific market condition, but rather merely considers the potential combined effect of a number of factors including, but not limited to, high carbon prices, low fuel costs, continuation of renewable subsidies and/or stronger renewable energy mandates. Specifically, the Environmental Focus Scenario assumes a requirement for DEC to serve approximately 8% of its total combined retail load with new renewable resources by 2028. This represents about twice the amount of renewable energy as compared to the Base Case. Additionally, EE is incorporated at an aspirational target as established in the merger settlement. As presented in the table below, the Environmental Focus Scenario includes additional renewables of approximately 1,850 MW nameplate (734 MW contribution to peak) in DEC as compared to the Base Case. Table 5-B below provides the renewable energy resources assumed in the Environmental Focus Scenario.

Table 5-B DEC Environmental Focus Scenario Renewables

DEC Renewables								
	MW Contribution to Summer Peak				MW Nameplate			
	Wind	Solar	Biomass/ Hydro	Total	Wind	Solar	Biomass/ Hydro	Total
2014	-	124	62	185	-	294	62	356
2015	-	218	69	287	-	519	69	589
2016	-	239	77	316	-	569	77	646
2017	-	256	84	340	-	609	84	693
2018	9	348	137	494	57	828	137	1,023
2019	40	437	179	656	264	1,041	179	1,485
2020	48	525	205	779	321	1,251	205	1,777
2021	57	607	238	901	378	1,444	238	2,060
2022	65	686	260	1,011	435	1,632	260	2,328
2023	74	763	294	1,131	492	1,817	294	2,602
2024	82	838	321	1,241	549	1,995	321	2,865
2025	91	927	349	1,368	606	2,208	349	3,163
2026	99	1,000	366	1,465	663	2,381	366	3,410
2027	108	1,064	381	1,553	720	2,534	381	3,635
2028	114	1,149	392	1,654	758	2,735	392	3,885

6. SCREENING OF GENERATION ALTERNATIVES

As previously discussed, the Company develops the load forecast and adjusts for the impacts of EE that have been pre-screened for cost-effectiveness. The growth in this adjusted load forecast and associated reserve requirements, along with existing unit retirements or purchased power contract expirations, creates a need for future generation. This need is partially met with DSM resources and the renewable resources required for compliance with NC REPS. The remainder of the future generation needs can be met with a variety of potential supply-side technologies.

For purposes of the 2013 IRP, the Company considered a diverse range of technology choices utilizing a variety of different fuels, including supercritical pulverized coal (SCPC) units with carbon capture and sequestration (CCS), integrated gasification combined cycle (IGCC) with carbon capture and sequestration, CTs, CC with duct firing, and nuclear units. In addition, Duke Energy Carolinas considered renewable technologies such as wind and solar in this year's screening analysis.

For the 2013 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 to pass the best alternatives from each of these three categories to the integration process. As in past years, the reason for the initial screening analysis is to determine the most viable and cost-effective resources for further evaluation. This initial screening evaluation is necessary to narrow down options to be further evaluated in the quantitative analysis process as discussed in Appendix A.

The results of these screening processes determine a smaller, more manageable subset of technologies for detailed analysis in the expansion planning model. The following list details the technologies that were passed on to the detailed analysis phase of the IRP process. The technical and economic screening is discussed in detail in Appendix F.

- Baseload – 2 x 1,117 MW Nuclear units (AP1000)
- Baseload – 680 MW – 2 x 1 Combined Cycle (Inlet Chiller and Fired)
- Baseload – 843 MW – 2 x 1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Peaking/Intermediate – 403 MW - 2 x 7FA.05 CTs
- Peaking/Intermediate – 805 MW - 4 x 7FA.05 CTs
- Renewable – 150 MW Wind - On-Shore
- Renewable – 25 MW Solar Photovoltaic (PV)

7. RESERVE CRITERIA

Background

The reliability of energy service is a primary input in the development of the resource plan. Utilities require a margin of generating capacity reserve in order to provide reliable service. Periodic scheduled outages are required to perform maintenance, inspections of generating plant equipment, and to refuel nuclear plants. Unanticipated mechanical failures may occur at any given time, which may require shutdown of equipment to repair failed components. Adequate reserve capacity must be available to accommodate these unplanned outages and to compensate for higher than projected peak demand due to forecast uncertainty and weather extremes. In addition, some capacity must also be available as operating reserve to maintain the balance between supply and demand on a real-time basis.

The amount of generating reserves needed to maintain a reliable power supply is a function of the unique characteristics of a utility system including load shape, unit sizes, capacity mix, fuel supply, maintenance scheduling, unit availabilities and the strength of the transmission interconnections with other utilities. There is no one standard measure of reserve capacity that is appropriate for all systems since these characteristics are particular to each individual utility.

In 2012, DEC and DEP hired Astrape Consulting to conduct a reserve margin study for each utility. Astrape conducted a detailed resource adequacy assessment that incorporated the uncertainty of weather, economic load growth, unit availability and transmission availability for emergency tie assistance. Astrape analyzed the optimal planning reserve margin based on providing an acceptable level of physical reliability and minimizing economic costs to customers. The most common physical metric used in the industry is to target a system reserve margin that satisfies the one day in 10 year Loss of Load Expectation (LOLE) standard. This standard is interpreted as one firm load shed event every 10 years due to a lack of generating capacity. From an economic perspective, as planning reserve margin increases, the total cost of reserves increases while the costs related to reliability events decline. Similarly, as planning reserve margin decreases, the cost of reserves decreases while the costs related to reliability events increases, including the costs to customers of loss of power. Thus, there is an economic optimum point where the cost of additional reserves plus the cost of reliability events to customers is minimized.

Based on past reliability assessments, results of the Astrape analysis, and to enhance consistency and communication regarding reserve targets, both DEC and DEP have adopted a 14.5% minimum planning reserve margin for scheduling new resource additions. Since capacity is generally added in large blocks to take advantage of economies of scale, it should be noted that planning reserve margins will often be somewhat higher than the minimum target.

Adequacy of Projected Reserves

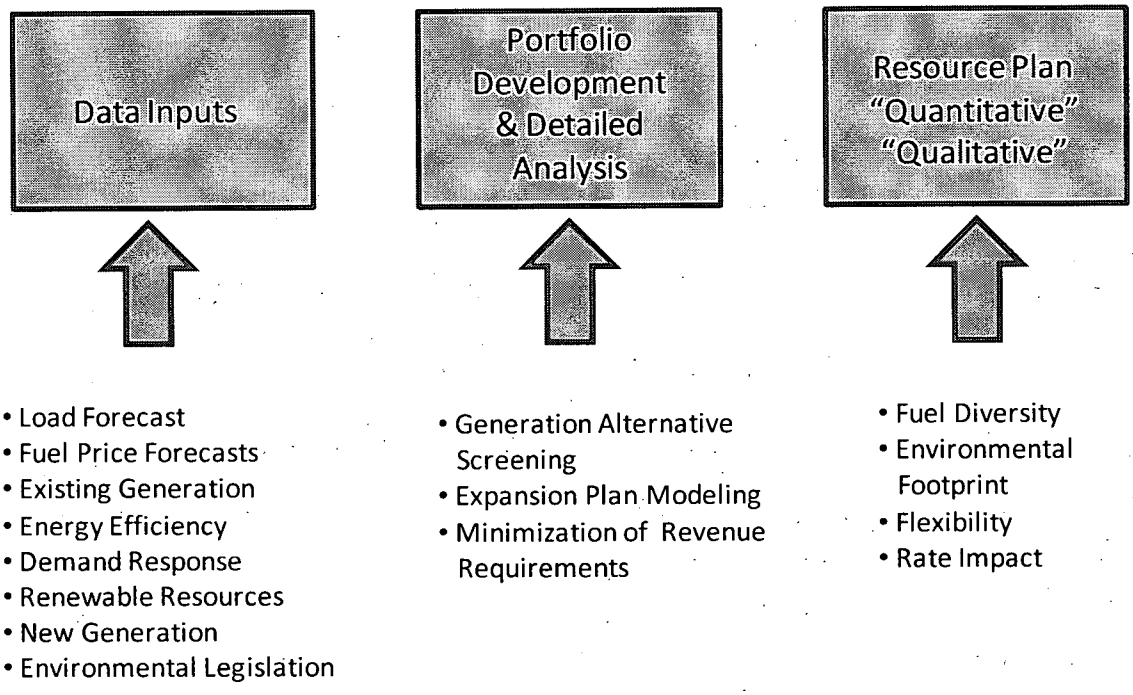
DEC's resource plan reflects reserve margins ranging from 14 to 22%. Reserves projected in DEC's IRP meet the minimum planning reserve margin target and thus satisfy the one day in 10 year LOLE criterion. Projected reserve margins exceed the minimum 14.5% target by 3% or more in 2019 as a result of the economic addition of a large combined cycle facility and in 2024-2028 as a result of the economic addition of large baseload additions in 2024 and 2026. Large resource additions are deemed economic only if they have a lower Present Value Revenue Requirement (PVRR) over the life of the asset as compared to smaller resources that better fit the short-term reserve margin need. Reserves projected in DEC's IRP are appropriate for providing an economic and reliable power supply.

8. EVALUATION AND DEVELOPMENT OF THE RESOURCE PLAN

To meet the future needs of DEC's customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, DEC develops a load forecast of energy sales and peak demand. To determine total resources needed, the Company considers the load obligation plus a 14.5% minimum planning reserve margin. The projected capability of existing resources, including generating units, EE and DSM, renewable resources 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 meet the load obligation while complying with all environmental and regulatory obligations. It should be noted that DEC considers the non-firm energy purchases and sales associated with the JDA with DEP in the development of its independent Base Case resource plan and two alternative scenarios to be discussed later in this chapter and in Appendix A.

Figure 8-A represents a simplified overview of the resource planning process. Appendix A of the Company's 2013 IRP provides a detailed discussion of the development of the resource plan.

Figure 8-A Simplified IRP Process



DEC performed its expansion plan modeling under Base Case assumptions that were updated as compared to its 2012 IRP. In addition to an updated Base Case expansion plan, DEC also considered an Environmental Focus Scenario that includes a greater amount of renewable resources and EE, as well as changes to other assumptions, such as fuel and CO_2 prices. Finally, DEC and DEP examined the potential benefits of sharing capacity as represented in a common Joint Planning Scenario.

Data Inputs

DEC utilizes updated data to develop its resource plan. For the 2013 IRP, data inputs such as load forecast, EE and DSM, fuel prices, projected CO_2 prices, individual plant operating and cost information, and future resource information were updated. These data inputs were developed and provided by company subject matter experts and/or based upon vendor studies, where available. Furthermore, DEC and DEP benefitted from the combined experience of both utilities' subject matter experts by utilizing best practices from each utility in the development of their respective IRP inputs. Where appropriate, common data inputs were applied.

As expected, certain data elements and issues have a larger impact on the plan than others. Any changes in these elements may result in a noticeable impact to the plan, and as such, these elements are closely monitored. Some of the most consequential data elements are listed below. A detailed discussion of each of these data elements has been presented throughout this document and is examined in more detail in the appendices to this document.

- Load Forecast
- EE/DSM
- Renewable Resource Projections
- Fuel Costs
- Technology Costs and Operating Characteristics
- Environmental Legislation
- Nuclear Issues

Generation Alternative Screening

DEC reviews generation resource alternatives on a technical and economic basis. Resources also must be demonstrated to be commercially available for utility scale operations. The resources that are found both technically and economically viable are then passed to the detailed analysis process for further analysis.

Portfolio Development and Detailed Analysis

The portfolio development and detailed analysis phase utilizes the information compiled in the data input step to derive resource portfolios or resource plans. This step in the IRP process utilizes expansion planning models and detailed production costing models. The goal of the modeling is to determine the best mix of capacity additions for the Company's short- and long-term resource plans with an objective of selecting a robust plan that minimizes the Present Value of Revenue Requirements and is environmentally sound complying with all state and federal regulations.

In the 2013 IRP, a Base Case along with an Environmental Focus Scenario and a Joint Planning Scenario were analyzed.

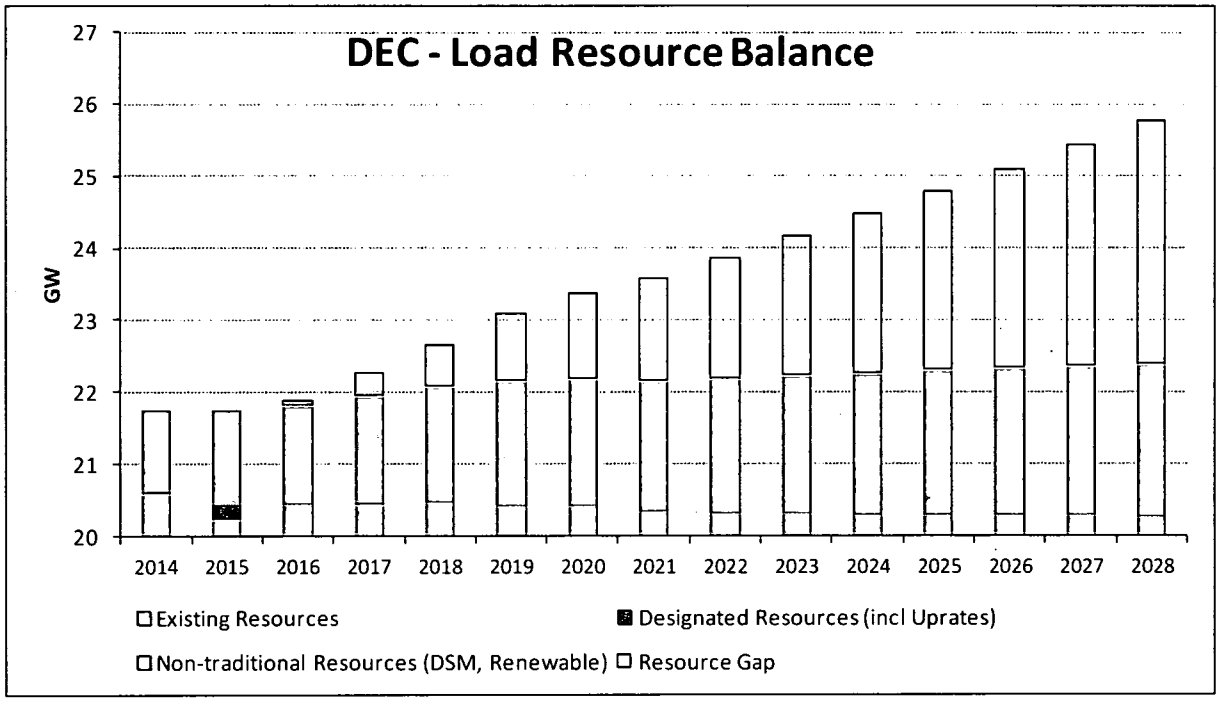
Resource Plans

Base Case

DEC produced an updated Base Case resource plan utilizing consistent assumptions and analytic methods between DEC and DEP where appropriate. This plan represents an update to the Company's 2012 IRP filing and does not take into account the sharing of capacity between DEC and DEP. However, the Base Case incorporates the JDA between DEC and DEP which represents a non-firm energy only commitment between the companies.

The Load and Resource Balance Chart shown in Chart 8-B illustrates the resource need that is required for DEC to meet its load obligation plus required reserves. The existing generating resources, designated resource additions and EE resources do not meet the required load and reserves and thus, the resource plan analysis will determine the most robust plan to meet this resource gap.

Chart 8-B DEC Load Resource Balance



Cumulative Resource Additions to Meet Load Obligation and Reserve Margin (MW)

Year	2014	2015	2016	2017	2018	2019	2020	2021
Resource Need	-	-	37	317	573	941	1,172	1,425
Year	2022	2023	2024	2025	2026	2027	2028	
Resource Need	1,682	1,935	2,218	2,463	2,753	3,064	3,358	

Tables 8-C and 8-D present the Load, Capacity and Reserves tables for the Base Case analysis that was completed for DEC's 2013 IRP.

Table 8-C Load, Capacity and Reserves Table - Summer

Summer Projections of Load, Capacity, and Reserves for Duke Energy Carolinas 2013 Annual Plan

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Load Forecast															
1 Duke System Peak	18,490	18,922	19,375	19,827	20,278	20,764	21,114	21,417	21,776	22,143	22,488	22,862	23,240	23,613	23,974
2 Firm Sale	150	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(111)	(184)	(275)	(382)	(490)	(600)	(708)	(819)	(929)	(1,040)	(1,110)	(1,219)	(1,318)	(1,404)	(1,477)
4 Adjusted Duke System Peak	**18,529**	**18,738**	**19,100**	**19,445**	**19,788**	**20,164**	**20,406**	**20,598**	**20,848**	**21,104**	**21,378**	**21,643**	**21,922**	**22,209**	**22,496**
Existing and Designated Resources															
5 Generating Capacity	20,366	20,386	20,218	20,218	20,263	20,263	20,263	20,259	20,259	20,259	20,259	20,259	20,259	20,259	20,259
6 Designated Additions / Uprates	20.3	202	0	45	0	0	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	(370)	0	0	0	0	(4)	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	**20,386**	**20,218**	**20,218**	**20,263**	**20,263**	**20,263**	**20,259**	**20,259**	**20,259**	**20,259**	**20,259**	**20,259**	**20,259**	**20,259**	**20,259**
Purchase Contracts															
9 Cumulative Purchase Contracts	**251**	**238**	**230**	**227**	**227**	**169**	**166**	**79**	**66**	**56**	**46**	**46**	**46**	**45**	**25**
Undesignated Future Resources															
10 Nuclear	0	0	0	0	66	0	66	0	0	0	1,117	0	1,117	0	0
11 Fossil	0	0	0	680	0	843	0	0	403	0	0	0	0	0	0
Renewables															
12 **Cumulative Renewables Capacity**	185	287	316	340	425	519	572	626	668	718	760	818	847	866	921
13 Cumulative Production Capacity	**20,823**	**20,744**	**20,764**	**21,510**	**21,661**	**22,540**	**22,653**	**22,619**	**23,051**	**23,091**	**24,240**	**24,298**	**25,444**	**25,462**	**25,497**
Demand Side Management (DSM)															
14 Cumulative DSM Capacity	**911**	**1,010**	**1,068**	**1,118**	**1,169**	**1,196**	**1,196**	**1,196**	**1,196**	**1,196**	**1,196**	**1,196**	**1,196**	**1,196**	**1,196**
15 Cumulative Capacity w/ DSM	**21,733**	**21,754**	**21,832**	**22,628**	**22,830**	**23,736**	**23,848**	**23,815**	**24,246**	**24,287**	**25,435**	**25,493**	**26,640**	**26,658**	**26,692**
Reserves w/ DSM															
16 Generating Reserves	3,204	3,016	2,732	3,183	3,042	3,572	3,442	3,217	3,399	3,183	4,057	3,850	4,718	4,448	4,196
17 % Reserve Margin	**17.3%**	**16.1%**	**14.3%**	**16.4%**	**15.4%**	**17.7%**	**16.9%**	**15.6%**	**16.3%**	**15.1%**	**19.0%**	**17.8%**	**21.5%**	**20.0%**	**18.7%**

Table 8-D Load, Capacity and Reserves Table – Winter

Winter Projections of Load, Capacity and Reserves for Duke Energy Carolinas 2013 Annual Plan

	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
Load Forecast															
1 Duke System Peak	17,717	18,177	18,595	19,000	19,410	19,818	20,165	20,463	20,803	21,150	21,510	21,866	22,234	22,589	22,938
2 Firm Sale	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(64)	(123)	(194)	(276)	(397)	(486)	(572)	(661)	(748)	(837)	(923)	(1,013)	(1,094)	(1,164)	(1,225)
4 Adjusted Duke System Peak	**17,678**	**18,053**	**18,401**	**18,724**	**19,013**	**19,332**	**19,593**	**19,802**	**20,054**	**20,313**	**20,588**	**20,853**	**21,140**	**21,425**	**21,713**
Existing and Designated Resources															
5 Generating Capacity	21,927	21,219	21,239	21,071	21,071	21,116	21,116	21,116	21,112	21,112	21,112	21,112	21,112	21,112	21,112
6 Designated Additions / Uprates	2	20	202	0	45	0	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	(710)	0	(370)	0	0	0	0	(4)	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	**21,219**	**21,239**	**21,071**	**21,071**	**21,116**	**21,116**	**21,116**	**21,112**	**21,112**	**21,112**	**21,112**	**21,112**	**21,112**	**21,112**	**21,112**
Purchase Contracts															
9 Cumulative Purchase Contracts	229	216	210	210	210	152	149	56	43	33	23	23	23	23	23
Undesignated Future Resources															
10 Nuclear	0	0	0	0	0	66	0	66	0	0	0	1,117	0	1,117	0
11 Fossil	0	0	0	0	711	0	875	0	0	443	0	0	0	0	0
Renewables															
12 Cumulative Renewables Capacity	62	112	119	127	134	168	214	221	234	238	252	260	270	268	263
13 Cumulative Production Capacity	**21,509**	**21,567**	**21,400**	**22,119**	**22,171**	**23,088**	**23,131**	**23,107**	**23,550**	**23,544**	**23,548**	**24,673**	**24,683**	**25,797**	**25,793**
Demand Side Management (DSM)															
14 Cumulative DSM Capacity	**561**	**584**	**604**	**626**	**649**	**649**	**649**	**649**	**649**	**649**	**649**	**649**	**649**	**649**	**649**
15 Cumulative Capacity w/ DSM	**22,070**	**22,151**	**22,004**	**22,745**	**22,820**	**23,737**	**23,780**	**23,756**	**24,199**	**24,193**	**24,197**	**25,322**	**25,332**	**26,446**	**26,442**
Reserves w/ DSM															
16 Generating Reserves	4,392	4,098	3,603	4,021	3,807	4,405	4,187	3,954	4,145	3,880	3,610	4,469	4,191	5,021	4,729
17 % Reserve Margin	**24.8%**	**22.7%**	**19.6%**	**21.5%**	**20.0%**	**22.8%**	**21.4%**	**20.0%**	**20.7%**	**19.1%**	**17.5%**	**21.4%**	**19.8%**	**23.4%**	**21.8%**

DEC - Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Summer 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.
   A firm wholesale backstand agreement for 47 MW between Duke Energy Carolinas and PMPA starts on 1/1/2014 and continues through the end of 2020.

2. A firm sale of 150 MW summer and 25 MW winter for FERC market power mitigation in 2014.

3. Cumulative energy efficiency and conservation programs (does not include demand response programs)

4. Peak load adjusted for firm sale and cumulative energy efficiency

5. Existing generating capacity reflecting designated additions, planned uprates, retirements and derates
   Includes 101 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for NCMPA1 firm capacity sale.

6. Capacity Additions include the conversion of Lee Steam Station unit 3 from coal to natural gas in 2015 (170 MW).
   Capacity Additions include Duke Energy Carolinas hydro units scheduled to be repaired and returned to service. These units are returned to service in the 2012-2015 timeframe and total 2 MW.
   Also included is a 96.5 MW capacity increase due to nuclear uprates at Catawba, McGuire, and Oconee. Timing of these uprates is shown from 2014-2017

7. The 370 MW capacity retirement in summer 2015 represents the projected retirement date for Lee Steam Station,
   Capacity Derate of 4 MW associated with Marshall 4 SCR is included in 2020
   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.

8. Sum of lines 5 through 7

9. Cumulative Purchase Contracts including purchased capacity from PURPA Qualifying Facilities, an 88 MW Cherokee County Cogeneration Partners contract which began in June 1998 and expires June 2020 and miscellaneous other QF projects.

10. New nuclear resources economically selected to meet load and minimum planning reserve margin
    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.
    10% share (allocated by load ratio basis with DEP) V.C. Summer Nuclear facility in 2018 and 2020 (66 MW in each year)
    1117 MW Lee Nuclear Unit additions in 2024 and 2026

DEC - Assumptions of Load, Capacity, and Reserves Table cont.

11. New fossil fuel resources economically selected to meet load and minimum planning reserve margin
    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.
    Addition of 680 MW of Combined Cycle capacity in 2017 (based on the need determined in 2012 IRP)
    Addition of 843 MW Advanced Combined Cycle units in 2019
    Addition of 403 MW of Combustion Turbine capacity in 2022

12. Cumulative solar, biomass, hydro and wind resources to meet NC REPS compliance
    Also includes a compliance plan for South Carolina as a placeholder to reflect a possible state or federal renewable standard beginning in 2018

13. Sum of lines 8 through 12

14. Cumulative Demand Side Management programs including load control and DSDR

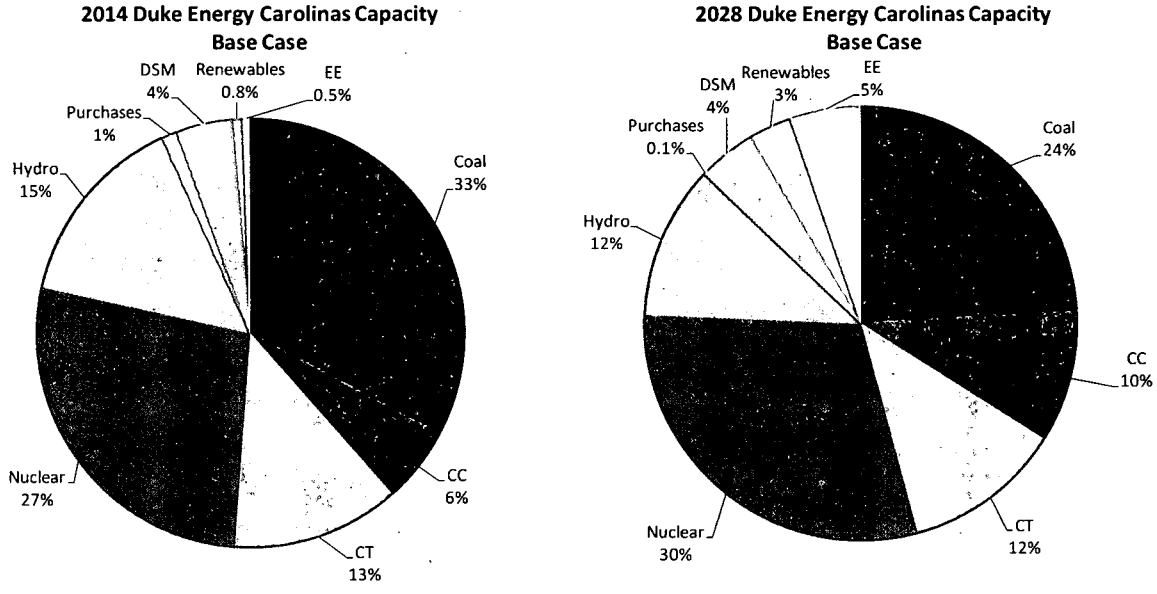
15. Sum of lines 13 and 14

16. The difference between lines 4 and 15

17. Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand
    Minimum target planning reserve margin is 14.5%

The following charts illustrate both the current and forecasted capacity by fuel type for the DEC system, as projected by the Base Case expansion plan. As demonstrated in Chart 8-E, the capacity mix for the DEC system changes with the passage of time. In 2028, the Base Case projects that DEC will have a smaller reliance on coal and a higher reliance on gas-fired resources, nuclear, renewable resources and EE as compared to the current state. Gas price projections continue to make natural gas an attractive resource for future capacity needs.

Chart 8-E Duke Energy Carolinas Capacity by Fuel Type – Base Case [1]



A detailed discussion of the assumptions, inputs and analytics used in the development of the Base Case is contained within Appendix A.

Environmental Focus Scenario

DEC also developed an Environmental Focus Scenario that includes aspirational EE targets, as well as contributions from renewable resources at levels approximately twice the level considered in the Base Case resource plan. This scenario illustrates the amount of traditional supply-side resources that would be eliminated or deferred if future market conditions and/or state and federal regulations resulted in higher levels of efficiency and renewable resources.

The supply-side resources were analyzed in light of the higher EE contributions and accounting for additional renewable resources. The Environmental Focus Scenario also assumed higher carbon prices

[1] In 2021, the REPS compliance plan of 12.5% is comprised of approximately 25% Energy Efficiency, 25% purchases of out-of-state RECs, 5-10% from RECs not associated with electrical energy (including animal waste resources), and the balance from purchases of renewable electricity.

and slightly lower fuel prices due to declining demand for fossil fuels. Table 8-F below represents the annual incremental additions reflected in the Environmental Focus Scenario expansion plan contrasted with the Base Case expansion plan.

Table 8-F DEC Environmental Focus Scenario

Duke Energy Carolinas Resource Plan Base Case		
Year	Resource	MW
2018	VC Summer Nuclear	66
2019	New CC	843
2020	VC Summer Nuclear	66
2021	-	-
2022	New CT	403
2023	-	-
2024	New Nuclear	1117
2025	-	-
2026	New Nuclear	1117
2027	-	-
2028	-	-

Duke Energy Carolinas Resource Plan Environmental Focus Scenario		
Year	Resource	MW
2018	VC Summer Nuclear	66
2019	-	-
2020	VC Summer Nuclear	66
2021	-	-
2022	New CC	843
2023	-	-
2024	New Nuclear	1117
2025	-	-
2026	New Nuclear	1117
2027	-	-
2028	-	-

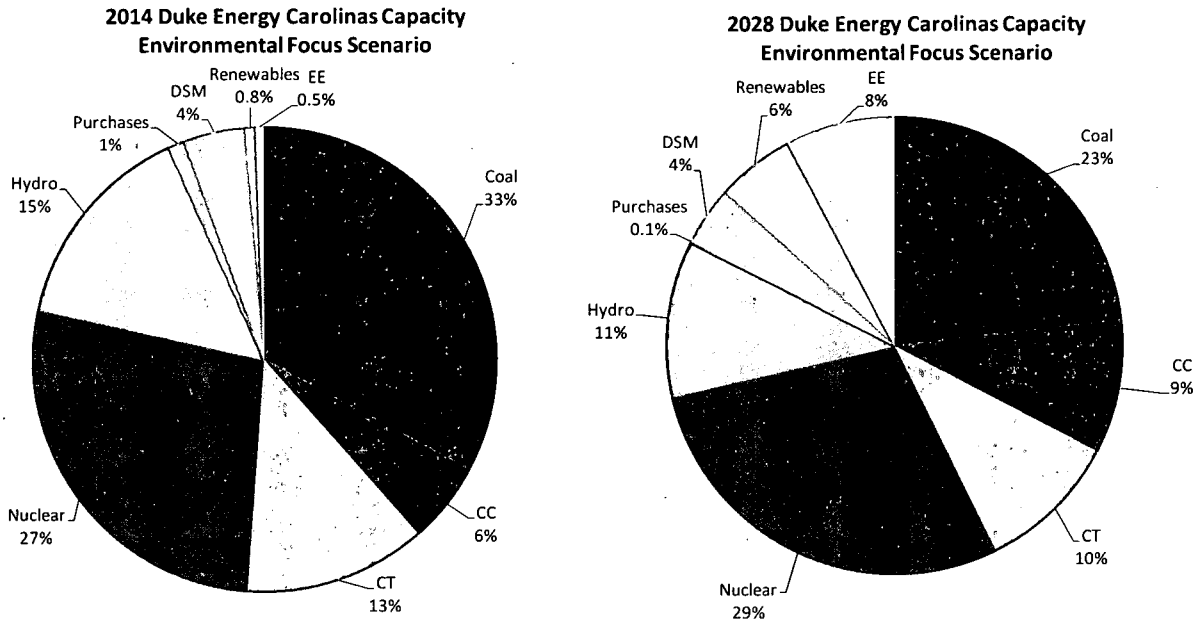
Note: Tables represent only undesignated resources from 2018 through 2028; no changes to the Base Case build plan occurred in prior years

The Environmental Focus Scenario results in the following changes as compared to the Base Case resource plan:

- Incremental increase in renewable energy resources of 1,857 MW nameplate (734 MW contribution to peak) by 2028
- Increase in EE of 724 MW by 2028
- Delay in the need for the new CC resource from 2019 to 2022
- CT resource in 2022 moves beyond 2028 timeframe

The following charts illustrate both the current and forecasted capacity by fuel type for the DEC system, as projected by the Environmental Focus Scenario expansion plan. Chart 8-G demonstrates the impacts of doubling the renewable resources as compared to the Base Case and including aspirational EE goals. The increase in EE and renewable resources reduce the Company's reliance on coal, hydro and CT resources. Natural gas CC and nuclear capacity is still economically selected in the Environmental Focus Scenario, thus increasing the impact that those baseload resources have on the system capacity mix.

Chart 8-G Duke Energy Carolinas Capacity by Fuel Type – Environmental Focus Scenario



Joint Planning Scenario

A Joint Planning Scenario that begins to explore the potential for DEC and DEP to share firm capacity between the companies was also developed. The focus of this scenario is to illustrate the potential for the utilities to collectively defer generation investment by utilizing each other's capacity when available and by jointly owning new capacity. This plan does not address the specific implementation methods or issues required to implement shared capacity. Rather, this scenario illustrates the benefits of joint planning between DEC and DEP with the understanding that the actual execution of capacity sharing would require separate regulatory proceedings and approvals.

Table 8-H below represents the annual non-renewable incremental additions reflected in the Joint Planning Scenario system expansion plan for the combined DEC and DEP Base Cases as compared to the Joint Planning Scenario. The plan contains the undesignated additions for DEC and DEP over the planning horizon.

Table 8-H DEC and DEP Joint Planning Scenario

Duke Energy Carolinas and Duke Energy Progress Base Case Combined Resource Plans

Year	Resource	MW
2014	-	-
2015	-	-
2016	-	-
2017	New CC	680
2018	Fast Start CT, VC Summer Nuclear	126, 667/46
2019	New CC, New CC	843, 843
2020	VC Summer Nuclear	667/46
2021	New CC	843
2022	New CC, New CT	843, 403
2023	-	-
2024	New Nuclear	1117
2025	-	-
2026	New Nuclear	1117
2027	New CT	403
2028	-	-

Delays 1 year

Delays 2 years & Need changes to CT

Delays 1 year

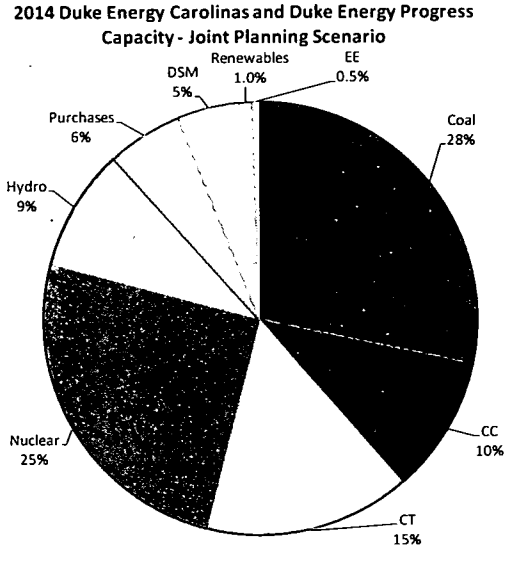
Outside Study Period

Duke Energy Carolinas and Duke Energy Progress Joint Planning Scenario Resource Plan

Year	Resource	MW
2014	-	-
2015	-	-
2016	-	-
2017	-	-
2018	Fast Start CT, New CC, VC Summer Nuclear	126, 680, 667/46
2019	New CC	843
2020	VC Summer Nuclear	667/46
2021	New CC, New CT	843, 403
2022	New CC	843
2023	New CT	403
2024	New Nuclear	659/458
2025	-	-
2026	New Nuclear	659/458
2027	-	-
2028	-	-

The following charts illustrate both the current and forecasted energy and capacity by fuel type for the DEC system, as projected by the Joint Planning Scenario. In this Joint Planning Scenario, the Companies continue to rely upon nuclear, CT and coal resources, but the reliance on natural gas CC resources increases due to the favorable natural gas prices. The Companies' renewable energy and EE impacts continue to grow over time, as also reflected in the Base Cases.

Chart 8-I DEC and DEP Capacity by Fuel Type – Joint Planning Scenario



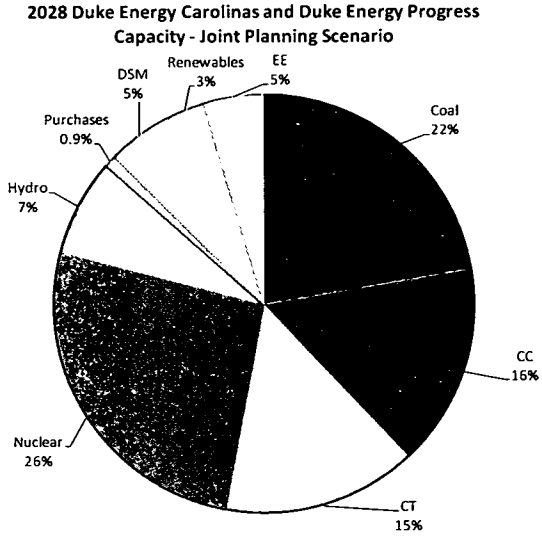
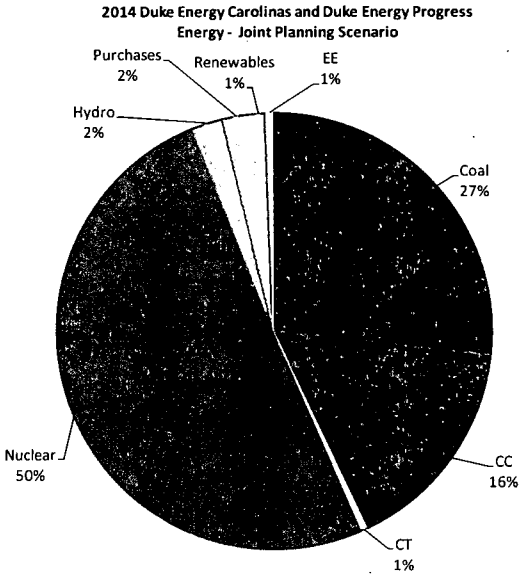
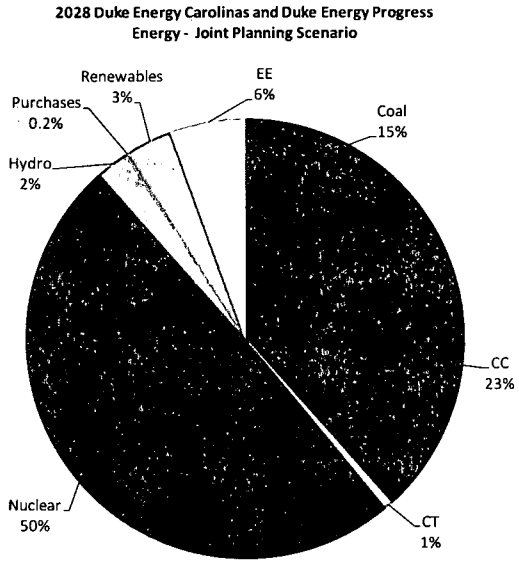


Chart 8-J DEC and DEP Energy by Fuel Type – Joint Planning Scenario





9. SHORT-TERM ACTION PLAN

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

- Take actions to ensure capacity needs beginning in 2017 are met.[2] As discussed later in this chapter, DEC issued a Request for Proposals (RFP) to address the 2017 capacity need. After evaluating multiple bids including a self-build option, the Company has determined the most economic alternative to meet the 2017 need is to construct a new natural gas combined cycle facility at the Lee Steam Station site in Anderson County S.C.

- Retire 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 were retired in October 2011 and April 2012, respectively, in advance of the initial testing of new generation at those locations. The remaining un-scrubbed coal units at Buck and Riverbend were retired in April 2013, nearly two years earlier than previously planned. The retirement of Lee Steam Station is currently planned for April 2015 to correspond with the compliance requirements of the Mercury and Air Toxics Standard. Duke Energy Carolinas also retired 350 MWs of its older CTs in October 2012.

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

- Continue to seek enhancements to the Company's DSM/EE portfolio by: (1) adding new or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new measurement and verification (M&V) results and (3) other EE research and development pilots.

- Completed construction of the new Dan River Combined Cycle unit. The unit was operational December 2012. The 620 MW natural gas-fired CC generating station achieves high operational flexibility and high thermal efficiency while utilizing state-of-the-art environmental control technology to minimize plant emissions.

- Completed construction of the 825 MW Cliffside Unit 6, at the existing Cliffside Steam Station. As of December 2012, Cliffside Unit 6 began commercial operation.

- Move forward with the conversion of Lee Steam Station Unit 3 from coal to natural gas fuel.

[2] While there is a slight capacity need in 2016, the Company will continue to monitor that small need and take action as necessary.

Lee Steam Station Unit 3 is reflected in the 2013 Duke Energy Carolinas IRP as a retired coal unit in the fourth quarter of 2014 and converted to natural gas before the summer peak of 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 2017 to 2028 timeframe.

  - DEC continues to explore the potential for a joint ownership share of the South Carolina Electric and Gas V.C. Summer nuclear station. The plan shows a 5.9% share of the two 1,100 units being available for the summer peaks of 2018 and 2020, respectively. While shown to be cost-effective from a planning perspective, the acquisition of this capacity is still subject to successful completion of discussions as well as multiple regulatory approvals.

  - The Company submitted an application for a Combined Construction and Operating License (COL) and an environmental report to the Nuclear Regulatory Commission (NRC) for W.S. Lee III (Lee) Nuclear on Dec. 12, 2007. A supplement to the environmental report was filed September 24, 2009. The NRC issued its Draft Environmental Impact Statement for the Lee Nuclear plant in December 2011, concluding that the NCUC's evaluation of DEC's future load demand and its accuracy in historical load forecasting within the 2011 IRP was a reasonable basis for planning.

  - In April 2012, the NRC staff subsequently requested Duke Energy Carolinas to update the Lee Nuclear site-specific seismic analysis to incorporate the new Central and Eastern United States (CEUS) Seismic Source Characterization model (published as NUREG-2115 in January 2012). This negatively impacts the schedule for NRC issuance of the Lee COL. Completion of the new site-specific seismic analysis will delay Lee COL issuance until second quarter 2016. Accordingly, DEC has moved the Commercial Operation Date (COD) for Lee Nuclear Unit 1 to 2024.

  - The Company continues to evaluate the optimal time to file the Certificate of Environmental Compatibility and Public Convenience and Necessity (CECPCN) for Lee Nuclear in South Carolina, as well as pursue 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 procure capacity, as appropriate. PPAs have been signed with developers of solar PV, landfill gas and wind resources. Additionally, 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 existing and potential environmental regulations such as MATS, the Coal Combustion Residuals rule, the Cross-State Air Pollution Rule (CSAPR) and the new ozone National Ambient Air Quality Standard (NAAQS).

- Continue to pursue existing and potential opportunities for wholesale power sales agreements within the Duke Energy balancing authority area.

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

- Continue to examine the benefits of joint capacity planning and pursue appropriate regulatory actions.

A summarization of the capacity resource changes for the Base Case in the 2013 IRP is shown in Table 9-A. Capacity retirements and additions are presented as incremental values in the year in which the change is projected to occur. The values shown for renewable resources, DSM and EE represent cumulative totals.

Table 9-A DEC Short-Term Action Plan

Duke Energy Carolinas Short-Term Action Plan							
			Renewable Resources (Cumulative Nameplate MW)				
Year	Retirements	Additions [1]	Wind [2]	Solar [2]	Biomass/Hydro [3]	EE	DSM [4]
2014		12 MW Nuc	0	294	62	111	911
2015	370 MW Lee 1-3 Coal	170 MW Lee NG Conv 20 MW Nuc	0	519	69	184	1010
2016			0	569	77	275	1068
2017		45 MW Nuc 680 MW CC	0	609	84	382	1118
2018		66 MW VC Summer	0	730	118	490	1169

Notes:

(1) Includes 77 MW of nuclear uprates

(2) Capacity is shown in nameplate ratings. For planning purposes, wind presents a 15% contribution to peak and solar has a 42% contribution to peak.

(3) Biomass includes swine and poultry contracts.

(4) Includes impacts of grid modernization.

DEC RFP Activity

Supply-Side

As determined in the Base Case, DEC's first significant capacity need is in 2017. DEC recognized the need for near-term capacity in its 2012 IRP which indicated a need for approximately 700 MW of capacity in the 2016 timeframe. Throughout the IRP analysis this need was met by a generic CC. Concurrent with the IRP analysis, DEC issued a RFP for capacity and energy on October 26, 2012. The RFP was for up to 700 MW of dispatchable, non-peaking capacity and energy available by either June 1, 2016 or June 1, 2017.

On November 27, 2012, DEC received multiple proposals from twelve companies including a DEC self-build bid for the construction of a natural gas combined cycle facility at the existing Lee Steam Station site in Anderson County, S.C. The bids were reviewed for compliance with RFP guidelines and were ranked economically to determine the least cost options. The initial economic analysis identified the short-listed bidders to continue proposal discussions. In late February 2013, DEC notified the short-listed bidders to provide refreshed proposals to meet capacity needs beginning June 2017.

Refreshed proposals received on May 29, 2013 were ranked economically and modeled utilizing detailed production cost modeling techniques. The results of detailed analysis including PROSYM

production cost modeling, along with all other fixed and variable revenue requirements, indicated the Lee CC self-build proposal to be the least-cost option of the refreshed proposals.

Renewable Energy

No renewable energy RFPs have been issued since the filing of DEC's 2012 IRP.

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 in the Base Case and for an Environmental Focus Scenario that reflects increased CO_2 cost, EE and renewables. The future resource needs were optimized based on DEC and DEP independently. However the benefits of jointly planning on a system basis for the Base Case and Environmental Focus Scenario were also presented.

A. Overview of Analytical Process

The analytical process consists of four steps:

1. Assess resource needs
2. Identify and screen resource options for further consideration
3. Develop portfolio configurations
4. Perform portfolio analysis

1. Assess Resource Needs

The required load and generation resource balance needed to meet future customer demands was assessed as outlined below:

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

Customer load growth, the expiration of purchased power contracts and additional asset retirements result in significant resource needs to meet energy and peak demands. The following assumptions impacted the 2013 resource plan:

- In the Base Case, the summer peak demand and energy growth after the impact of energy efficiency averaged 1.5% through 2028. In the Environmental Focus Scenario after the impact of energy efficiency, summer peak demand growth averaged 1.3% and energy growth averaged 1.2% over the next 15 years
- Retirement of an additional 350 MW of old fleet combustion turbines and 710 MW of older coal units since the 2012 IRP filing
- Retirement of an additional 370 MW at Lee Steam Station by April 2015

- Continued operational reliability of existing generation portfolio
- A 14.5% minimum planning reserve margin for the planning horizon

2. Identify and Screen Resource Options for Further Consideration

The IRP process evaluated EE, DSM and supply-side options to meet customer energy and capacity needs. The Company developed EE and DSM options for consideration within the IRP based on existing EE/DSM program experience, the most recent market potential study, input from its EE/DSM Collaborative 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:

- Technical feasibility and commercial availability in the marketplace
- Compliance with all federal and state requirements
- Long-run reliability
- Reasonableness of 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. An overview of resources screened on technical basis and a levelized economic basis is shown in Appendix F.

Resource Options

Supply-Side

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 – 2 x 1,117 MW Nuclear units (AP1000)
- Baseload – 132 MW Purchase of V. C. Summer Nuclear (AP1000)
- Baseload – 680 MW – 2 x 1 Combined Cycle (Inlet Chiller and Fired)
- Baseload – 843 MW – 2 x 1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Peaking/Intermediate – 403 MW – 2 x 7FA.05 CTs
- Peaking/Intermediate – 805 MW – 4 x 7FA.05 CTs
- Renewable – 150 MW – On-shore Wind
- Renewable – 25 MW – Solar PV

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 DSM and EE programs in the IRP analysis. As described in Appendix D, EE and DSM measures are compared to generation alternatives to identify cost-effective EE and DSM programs.

In the Base Case, the Company modeled the program costs associated with EE and DSM based on a combination of both internal company expectations and projections based on information from the 2013 update of the Company's 2011 market potential study. In the DEC and DEP merger settlement agreement, the Company agreed to aspire to a more aggressive implementation of EE throughout the planning horizon, and the impacts of this goal were incorporated in the Environmental Focus Scenario. The program costs used for this analysis leveraged the Company's internal projections for the first five years. In the longer term, updated market potential study data incorporating the impacts of customer participation rates over the range of potential programs.

3. Develop Portfolio Configurations

The Company conducted a screening analysis using a simulation model to identify the most attractive capacity options under the expected load profile for both the Base Case and Environmental Focus Scenario. The set of basic inputs included:

- CO_2 price starting in 2020 increasing throughout the planning horizon
  - Base Case - 17 $/ton in 2020 increasing to 33 $/ton by 2028
  - Environmental Focus Scenario - 20 $/ton in 2020 increasing to 45 $/ton by 2028;
- Coal, natural gas and fuel oil
  - Short-term: Based on the market observations
  - Long-term: Based on the Company's fundamental fuel price projections
  - For the Environmental Focus Scenario, the Company's fundamental fuel price projection incorporated the impact of different CO_2, EE and renewable requirements consistent with that scenario
- Availability and operating and maintenance cost for both new and existing generation
- Compliance with current and potential environmental regulations,
- Financial updates including cost of capital, escalation and discount rates
- System operational needs for load ramping, and spinning reserves

- The projected load and generation resource need incorporating the impacts of EE and DSM.
    - ➢ The Base Case reflects EE savings projections based on the updated market potential study at the end of the planning horizon
    - ➢ The Environmental Focus Scenario assumes full compliance with the Duke Energy-Progress Energy merger settlement agreement with the cumulative EE achievements since 2009 counted toward the cumulative settlement agreement impacts
- Compliance with NC REPS requirements and a placeholder renewable requirement for South Carolina that could represent a federal or state program starting in 2018
    - ➢ The Environmental Focus Scenario reflects a doubling of the amount of renewables included in the Base Case by 2028

4. Perform Portfolio Analysis

For the Base Case and Environmental Focus Scenario, the optimal portfolios were developed for DEC without the benefit of sharing capacity with DEP. To demonstrate the value of sharing capacity with DEP, a Joint Planning Scenario was developed that examined how the combined plans of DEC and DEP would change if a 14.5% minimum planning reserve margin was applied at the combined system level rather than the individual company level.

An overview of the specific details of the optimal portfolios for both the Base Case and Environmental Focus Scenario without the benefit of sharing capacity with DEP is shown in Table A-1 below.

Table A-1 DEC Optimal Portfolios

	Optimal Portfolios	
	Base	Environmental Focus
2014		
2015		
2016		
2017	680 MW (CC)	680 MW (CC)
2018	66 MW (V.C. Summer N)	66 MW (V.C. Summer N)
2019	843 MW (Adv CC)	
2020	66 MW (V.C. Summer N)	66 MW (V.C. Summer N)
2021		
2022	403 MW (CT)	843 MW (Adv CC)
2023		
2024	1,117 MW (N)	1,117 MW (N)
2025		
2026	1,117 MW (N)	1,117 MW (N)
2027		
2028		
Total CTs	403 MW	
Total CCs	1,523 MW	1,523 MW
Total Nuclear	2,366 MW	2,366 MW

Note: This table includes only new, undesignated resources.

The first resource need was determined to be in 2017 in both the Base Case and Environmental Focus Scenario. In addition to significant levels of EE, DSM and renewable resources, combined cycle generation was selected as the most economical resource to meet this need. In both the Base Case and Environmental Focus Scenario, the optimized portfolios included 5.9% ownership in the V.C. Summer Nuclear Station in 2018 and 2020 and the addition of the W. S. Lee Nuclear Station in 2024 and 2026. These nuclear resources were selected economically utilizing the capacity expansion model.

Even though shared V.C. Summer Nuclear was selected and incorporated in the Base Case and two additional scenarios of this IRP, the procurement of any portion of V.C. Summer is dependent on arriving at commercially acceptable terms with Santee Cooper.

The Environmental Focus Scenario incorporates a more aggressive EE portfolio and doubles the amount of renewable resources by 2028. The impact of these additions allowed for a deferral of the need of the Advanced CC in 2019 to 2022. In addition, the 2022 CT need was delayed beyond the 15-year planning horizon. However, because of the higher CO_2 price projection, increased revenue requirements associated with higher EE and increased cost associated with doubling the amount of renewables, the Environmental Focus Scenario present value of revenue requirements (PVRR)

through 2028 is $2 billion more than the Base Case even with deferral of the advanced CC and CT resources.

An evaluation was performed comparing the DEC and DEP optimally selected Base Case portfolios to a combined Joint Planning Scenario where existing and future capacity resources could be shared between DEC and DEP to meet a minimum 14.5% planning reserve margin. In this Joint Planning Scenario, sharing the W.S. Lee nuclear station on a load ratio basis with DEP was the best economic selection. Table A-2 shows the total incremental natural gas and nuclear capacity needed to meet the projected minimum planning reserve margin between 2014 and 2028 for DEC and DEP if separately planned. The total of these two combined resource requirements is then compared to the amount of resources needed if DEC and DEP were to jointly plan.

Table A-2 Comparison of Base Case Portfolio to Joint Planning Scenario

DEC Base Case (MW)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Gas Units				680		843			403						
Nuclear					66		66				1117		1117		
DEP Base Case (MW)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Gas Units						843		843	843					403	
Nuclear					46		46								
DEC & DEP Combined Base Case (MW)				680	112	1686	112	843	1246		1117		1117	403	
Combined Base Case Reserve Margin	17.7%	17.7%	16.0%	16.6%	15.7%	18.6%	17.2%	16.6%	18.0%	16.8%	18.6%	17.8%	19.4%	19.1%	17.4%
Joint Planning Case (MW)					792	843	112	1246	843	403	1117		1117		
Joint Planning Case Reserve Margin	17.7%	17.7%	16.0%	14.6%	15.7%	16.1%	14.8%	15.3%	15.6%	15.6%	17.4%	16.6%	18.3%	16.8%	15.2%

A comparison of the DEC and DEP Combined Base Case resource requirements to the Joint Planning Scenario requirements illustrates the ability to defer CC and CT resources over the 2014 through 2028 planning horizon. Consequently, the Joint Planning Scenario also results in a lower overall reserve margin. This is confirmed by a review of the reserve margins for the Combined Base Case as compared to the Joint Planning Scenario, which averaged 17.6% and 16.0%, respectively, from the first resource need in 2017 through 2028. The lower reserve margin in the Joint Planning Scenario indicates that DEC and DEP are more efficiently and economically meeting capacity needs. This is reflected in a total PVRR savings of $0.4 billion for the Joint Planning Scenario as compared to the Base Case through 2028.

B. Quantitative Analysis Summary

The quantitative analysis resulted in several key takeaways that impact near-term decision- making as well as planning for the longer term.

1. The Base Case and Environmental Focus Scenario show optimal portfolios that recognize the need for new generation in 2017 to meet the minimum reserve margin requirement. The results of this analysis show that this need is best met with CC generation

2. The ability to jointly plan with DEP provides customer savings by allowing for the deferral of new generation resources over the 2014 through 2028 planning horizon.

3. New nuclear generation is selected as an economic resource for the Base Case and Environmental Focus Scenario. In the 15-year planning horizon, a 5.9% ownership in the V.C. Summer in 2018 and 2020 and the addition of the Lee Nuclear in 2024 and 2026 were selected.

The Base Case and Environmental Focus Scenario analyses support 100% ownership of Lee Nuclear by DEC. However the Company continues to consider the benefits of regional nuclear generation. The idea of sharing new baseload generation resources between multiple parties allows for resource additions to be better matched with load growth and for new construction risk to be shared among the parties. This results in positive benefits for the Company's customers. Duke Energy Corporation is in discussions with Santee Cooper concerning the potential acquisition of a 10% ownership interest in the new nuclear units at V.C. Summer Units 2 and 3. The parties are discussing the commercial terms and currently have not reconciled differences and no contract has been signed. Any participation in the V.C. Summer project is premised on successful resolution of outstanding commercial items and continued demonstration of customer benefits. The parties are working towards a final decision in the next several months. If Duke Energy was to procure an ownership interest in V.C. Summer Units 2 and 3, the ownership is expected to be shared between DEC and DEP on a load ratio basis. The benefits of co-ownership of the Lee Nuclear facility with DEP were also illustrated with the ability to jointly plan as represented in the Joint Planning Scenario described above.

There are several challenges that have impacted the schedule for the Lee Nuclear facility. In March 2012, the NRC issued a request for information letter to operating power reactor licensees regarding recommendations of the Near-Term Task Force review of insights from the Fukushima Dai-ichi accident. In April 2012, the NRC staff subsequently requested DEC to update the Lee Nuclear site-specific seismic analysis to incorporate the new Central and Eastern United States (CEUS) Seismic Source Characterization model (published as NUREG-2115 in January 2012). Work on a new Lee Nuclear site-specific analysis implementing the new CEUS seismic model is underway. However, completion of the new seismic analysis is not expected before January 2014. This negatively impacts the schedule for NRC issuance of the Lee Nuclear COL. Completion of the new site-

specific seismic analysis will delay Lee COL issuance until second quarter 2016. Accordingly, Duke Energy Carolinas has moved the commercial operation date for Lee Nuclear Unit 1 to 2024.

In addition, the NRC issued an updated Waste Confidence Rule in 2010 affirming that the agency has reasonable assurance utility spent fuel can be safely stored for at least 60 years after a power reactor's operating license expires. Waste confidence is central to the agency's ability to license new reactors and renew the operating licenses of existing reactors. On June 8, 2012, the U.S. Court of Appeals of the District of Columbia Circuit issued a decision vacating the updated Waste Confidence Rule and remanding it to the NRC for further proceedings. The Court held that the NRC's analysis was insufficient to support its findings that the permanent storage will be available "when necessary" and that spent fuel can safely be stored on-site at nuclear plants for 60 years after the expiration of a plant's license. In response to the remand decision, numerous parties filed a petition to suspend final decisions in all pending reactor licensing proceedings pending completion of remanded waste confidence proceedings in new nuclear and license renewal proceedings pending before the NRC. On August 7, 2012, the NRC issued an order on the petition stating that: (1) it is considering all options for resolving the waste confidence issues, which could include generic or site specific actions, but has not yet determined a course of action, (2) it will not issue licenses dependent on the Waste Confidence Rule until the Court's remand is appropriately addressed, however, this determination extends only to final license issuance, and (3) all licensing reviews and proceedings should continue to move forward. The NRC expects this issue to be resolved in August 2014. Waste Confidence must be resolved to support issuance of the Lee Nuclear COL. However, based on current schedules, this is not expected to impact issuance of the Lee Nuclear COL.

The PVRR results presented in the IRP analysis were based on a 15-year planning horizon, but the economics supporting new nuclear were extended to 2052 to capture the long-term benefits of the low production cost and carbon-free generation. It is important to note that while V.C. Summer and Lee Nuclear facilities were selected economically, they would also serve as replacement carbon-free baseload generation if existing nuclear generation is retired in the future. In 2033, the current operating license for Oconee Nuclear Station expires. At this time, the Company has not made a decision concerning seeking a second license extension for this plant. Oconee Nuclear Station is a significant part of DEC's generation portfolio representing over 2,500 MW of capacity and annual energy output of approximately 20,000 GWh. As such, it is important to start to examine the impacts of any potential retirement of Oconee Nuclear Station as compared to new nuclear generation to assist the Company as it considers seeking a second license extension.

One of the major benefits of having additional nuclear generation is the lower system CO_2 footprint. Assuming regional nuclear planning with DEP, DEC procures its load ratio share of the 10% interest of V.C. Summer and sharing Lee Nuclear Stations, the resulting reduction in CO_2 emissions is approximately 6 million tons of CO_2 for DEC and DEP by 2028 (from a 2013 baseline). This

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.

The Company's planning process must be dynamic and adaptable to changing conditions. This resource plan is the most appropriate resource plan at this point in time. However, good business practice requires DEC to continue to study the options and make adjustments as necessary and practical to reflect improved information and changing circumstances. Consequently, a strong business planning framework is truly an evolving process that can never be considered complete.

APPENDIX B: DUKE ENERGY CAROLINAS OWNED GENERATION

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 2012, Duke Energy Carolinas' nuclear and coal-fired generating units met the vast majority of customer needs by providing 62% and 31%, respectively, of Duke Energy Carolinas' energy from generation. Hydroelectric generation, Combustion Turbine generation, Combined Cycle generation, solar generation, long term PPAs, and economical purchases from the wholesale market supplied the remainder.

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.

Existing Generating Units and Ratings [a, b, c, d]
All Generating Unit Ratings are as of January 1, 2013

Coal						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Allen	1	167	162	Belmont, N.C.	Coal	Intermediate
Allen	2	167	162	Belmont, N.C.	Coal	Intermediate
Allen	3	270	261	Belmont, N.C.	Coal	Intermediate
Allen	4	282	276	Belmont, N.C.	Coal	Intermediate
Allen	5	275	266	Belmont, N.C.	Coal	Intermediate
Belews Creek	1	1135	1110	Belews Creek, N.C.	Coal	Base
Belews Creek	2	1135	1110	Belews Creek, N.C.	Coal	Base
Cliffside	5	556	552	Cliffside, N.C.	Coal	Base
Cliffside	6	825	825	Cliffside, N.C.	Coal	Base
Lee	1	100	100	Pelzer, S.C.	Coal	Peaking
Lee	2	102	100	Pelzer, S.C.	Coal	Peaking
Lee	3	170	170	Pelzer, S.C.	Coal	Peaking
Marshall	1	380	380	Terrell, N.C.	Coal	Intermediate
Marshall	2	380	380	Terrell, N.C.	Coal	Intermediate
Marshall	3	658	658	Terrell, N.C.	Coal	Base
Marshall	4	660	660	Terrell, N.C.	Coal	Base
Total NC		6,890	6,802			
Total SC		372	370			
Total Coal		7,262	7,172			

Combustion Turbines						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Lee	7C	41	41	Pelzer, S.C.	Natural Gas/Oil-Fired	Peaking
Lee	8C	41	41	Pelzer, S.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	1	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	2	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	3	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	4	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	5	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	6	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	7	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	8	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	9	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	10	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	11	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	12	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	13	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	14	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	15	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	16	93	79.2	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	1	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	2	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	3	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	4	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	5	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	6	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	7	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	8	92.4	74.42	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	1	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	2	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	3	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	4	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	5	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Total NC		2,383	2,092			
Total SC		821.2	677.4			
Total CT		3,204	2,770			

Combined Cycle						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Buck	CT11	170	165	Salisbury, N.C.	Natural Gas	Base
Buck	CT12	170	165	Salisbury, N.C.	Natural Gas	Base
Buck	ST10	300	290	Salisbury, N.C.	Natural Gas	Base
Buck CTCC		640	620			
Dan River	CT8	170	165	Eden, N.C.	Natural Gas	Base
Dan River	CT9	170	165	Eden, N.C.	Natural Gas	Base
Dan River	ST7	300	290	Eden, N.C.	Natural Gas	Base
Dan River CTCC		640	620			
Total CTCC		1,280	1,240			

Pumped Storage						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Jocassee	1	195	195	Salem, S.C.	Pumped Storage	Peaking
Jocassee	2	195	195	Salem, S.C.	Pumped Storage	Peaking
Jocassee	3	195	195	Salem, S.C.	Pumped Storage	Peaking
Jocassee	4	195	195	Salem, S.C.	Pumped Storage	Peaking
Bad Creek	1	340	340	Salem, S.C.	Pumped Storage	Peaking
Bad Creek	2	340	340	Salem, S.C.	Pumped Storage	Peaking
Bad Creek	3	340	340	Salem, S.C.	Pumped Storage	Peaking
Bad Creek	4	340	340	Salem, S.C.	Pumped Storage	Peaking
Total Pump Stor		2,140	2,140			

Hydro						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
99 Islands	1	1.6	1.6	Blacksburg, S.C.	Hydro	Peaking
99 Islands	2	1.6	1.6	Blacksburg, S.C.	Hydro	Peaking
99 Islands	3	1.6	1.6	Blacksburg, S.C.	Hydro	Peaking
99 Islands	4	1.6	1.6	Blacksburg, S.C.	Hydro	Peaking
99 Islands	5	0	0	Blacksburg, S.C.	Hydro	Peaking
99 Islands	6	0	0	Blacksburg, S.C.	Hydro	Peaking
Bear Creek	1	9.45	9.45	Tuckasegee, N.C.	Hydro	Peaking
Bridgewater	1	15	15	Morganton, N.C.	Hydro	Peaking
Bridgewater	2	15	15	Morganton, N.C.	Hydro	Peaking
Bridgewater	3	1.5	1.5	Morganton, N.C.	Hydro	Peaking
Bryson City	1	0.48	0.48	Whittier, N.C.	Hydro	Peaking
Bryson City	2	0	0	Whittier, N.C.	Hydro	Peaking
Cedar Cliff	1	6.4	6.4	Tuckasegee, N.C.	Hydro	Peaking
Cedar Creek	1	15	15	Great Falls, S.C.	Hydro	Peaking
Cedar Creek	2	15	15	Great Falls, S.C.	Hydro	Peaking
Cedar Creek	3	15	15	Great Falls, S.C.	Hydro	Peaking
Cowans Ford	1	81.3	81.3	Stanley, N.C.	Hydro	Peaking
Cowans Ford	2	81.3	81.3	Stanley, N.C.	Hydro	Peaking
Cowans Ford	3	81.3	81.3	Stanley, N.C.	Hydro	Peaking
Cowans Ford	4	81.3	81.3	Stanley, N.C.	Hydro	Peaking
Dearborn	1	14	14	Great Falls, S.C.	Hydro	Peaking
Dearborn	2	14	14	Great Falls, S.C.	Hydro	Peaking
Dearborn	3	14	14	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	1	11	11	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	2	9.5	9.5	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	3	9.5	9.5	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	4	11	11	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	5	8	8	Great Falls, S.C.	Hydro	Peaking
Franklin	1	0	0	Franklin, N.C.	Hydro	Peaking
Franklin	2	0.6	0.6	Franklin, N.C.	Hydro	Peaking
Gaston Shoals	3	0	0	Blacksburg, S.C.	Hydro	Peaking
Gaston Shoals	4	1	1	Blacksburg, S.C.	Hydro	Peaking
Gaston Shoals	5	1	1	Blacksburg, S.C.	Hydro	Peaking
Gaston Shoals	6	0	0	Blacksburg, S.C.	Hydro	Peaking

Hydro cont.						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Great Falls	1	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	2	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	3	0	0	Great Falls, S.C.	Hydro	Peaking
Great Falls	4	0	0	Great Falls, S.C.	Hydro	Peaking
Great Falls	5	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	6	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	7	0	0	Great Falls, S.C.	Hydro	Peaking
Great Falls	8	0	0	Great Falls, S.C.	Hydro	Peaking
Keowee	1	76	76	Seneca, S.C.	Hydro	Peaking
Keowee	2	76	76	Seneca, S.C.	Hydro	Peaking
Lookout Shoals	1	9.3	9.3	Statesville, N.C.	Hydro	Peaking
Lookout Shoals	2	9.3	9.3	Statesville, N.C.	Hydro	Peaking
Lookout Shoals	3	9.3	9.3	Statesville, N.C.	Hydro	Peaking
Mission	1	0	0	Murphy, N.C.	Hydro	Peaking
Mission	2	0	0	Murphy, N.C.	Hydro	Peaking
Mission	3	0.6	0.6	Murphy, N.C.	Hydro	Peaking
Mountain Island	1	14	14	Mount Holly, N.C.	Hydro	Peaking
Mountain Island	2	14	14	Mount Holly, N.C.	Hydro	Peaking
Mountain Island	3	17	17	Mount Holly, N.C.	Hydro	Peaking
Mountain Island	4	17	17	Mount Holly, N.C.	Hydro	Peaking
Nantahala	1	50	50	Topton, N.C.	Hydro	Peaking
Oxford	1	20	20	Conover, N.C.	Hydro	Peaking
Oxford	2	20	20	Conover, N.C.	Hydro	Peaking
Queens Creek	1	1.44	1.44	Topton, N.C.	Hydro	Peaking
Rhodhiss	1	9.5	9.5	Rhodhiss, N.C.	Hydro	Peaking
Rhodhiss	2	11.5	11.5	Rhodhiss, N.C.	Hydro	Peaking
Rhodhiss	3	9	9	Rhodhiss, N.C.	Hydro	Peaking
Rocky Creek	1	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	2	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	3	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	4	0	0	Great Falls, S.C.	Hydro	Peaking

Hydro cont.						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Rocky Creek	5	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	6	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	7	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	8	0	0	Great Falls, S.C.	Hydro	Peaking
Tuxedo	1	3.2	3.2	Flat Rock, N.C.	Hydro	Peaking
Tuxedo	2	3.2	3.2	Flat Rock, N.C.	Hydro	Peaking
Tennessee Creek	1	9.8	9.8	Tuckasegee, N.C.	Hydro	Peaking
Thorpe	1	19.7	19.7	Tuckasegee, N.C.	Hydro	Peaking
Tuckasegee	1	2.5	2.5	Tuckasegee, N.C.	Hydro	Peaking
Wateree	1	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	2	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	3	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	4	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	5	17	17	Ridgeway, S.C.	Hydro	Peaking
Wylie	1	18	18	Fort Mill, S.C.	Hydro	Peaking
Wylie	2	18	18	Fort Mill, S.C.	Hydro	Peaking
Wylie	3	18	18	Fort Mill, S.C.	Hydro	Peaking
Wylie	4	18	18	Fort Mill, S.C.	Hydro	Peaking
Total NC		623.97	623.97			
Total SC		465.4	465.4			
Total Hydro		1,089.37	1,089.37			

Solar						
		Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
NC Solar		8.43	8.43	N.C.	Solar	Intermediate
Total Solar		8.43	8.43			

Nuclear						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
McGuire	1	1156	1129	Huntersville, N.C.	Nuclear	Base
McGuire	2	1156	1129	Huntersville, N.C.	Nuclear	Base
Catawba	1	1163	1129	York, S.C.	Nuclear	Base
Catawba	2	1163	1129	York, S.C.	Nuclear	Base
Oconee	1	865	846	Seneca, S.C.	Nuclear	Base
Oconee	2	865	846	Seneca, S.C.	Nuclear	Base
Oconee	3	865	846	Seneca, S.C.	Nuclear	Base
Total NC		2,312	2,258			
Total SC		4,921	4,796			
Total Nuclear		7,233	7,054			

Total Generation Capability		
	Winter Capacity (MW)	Summer Capacity (MW)
TOTAL DEC SYSTEM - N.C.	13,497	13,025
TOTAL DEC SYSTEM - S.C.	8,720	8,449
TOTAL DEC SYSTEM	22,217	21,473

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: 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 d: 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%
PMPA	12.5%

Planned Uprates			
Unit	Date	Winter MW (40%)	Summer MW
McGuire 1[a, b]	Jan 2013	11.6	29
McGuire 2[a, b]	Jan 2013	11.6	29
McGuire 2[a]	Oct 2013	13	32.5
Catawba 1[a]	Oct 2014	8	20
McGuire 1[a]	Apr 2015	13	32.5
Oconee 1	Jan 2017	6.0	15
Oconee 2	Jan 2017	6.0	15
Oconee 3	Jan 2017	6.0	15

Note a: The uprate capacity represented in this table is the total operating capacity addition and is not adjusted for the Joint Exchange Agreement for Catawba and McGuire. The adjusted values are utilized in the resource plan

Note b: Unit uprate effective as of January 1, 2013; capacity reflected in Existing Generating Units and Ratings section.

Retirements				
Unit & Plant Name	Location	Capacity (MW) Summer	Fuel Type	Expected Retirement Date
Buck 3[a]	Salisbury, N.C.	75	Coal	RETIRED
Buck 4[a]	Salisbury, N.C.	38	Coal	RETIRED
Cliffside 1[a]	Cliffside, N.C.	38	Coal	RETIRED
Cliffside 2[a]	Cliffside, N.C.	38	Coal	RETIRED
Cliffside 3[a]	Cliffside, N.C.	61	Coal	RETIRED
Cliffside 4[a]	Cliffside, N.C.	61	Coal	RETIRED
Dan River 1[a]	Eden, N.C.	67	Coal	RETIRED
Dan River 2[a]	Eden, N.C.	67	Coal	RETIRED
Dan River 3[a]	Eden, N.C.	142	Coal	RETIRED
Buzzard Roost 6C[b]	Chappels, S.C.	22	Combustion Turbine	RETIRED
Buzzard Roost 7C[b]	Chappels, S.C.	22	Combustion Turbine	RETIRED
Buzzard Roost 8C[b]	Chappels, S.C.	22	Combustion Turbine	RETIRED
Buzzard Roost 9C[b]	Chappels, S.C.	22	Combustion Turbine	RETIRED
Buzzard Roost 10C[b]	Chappels, S.C.	18	Combustion Turbine	RETIRED
Buzzard Roost 11C[b]	Chappels, S.C.	18	Combustion Turbine	RETIRED
Buzzard Roost 12C[b]	Chappels, S.C.	18	Combustion Turbine	RETIRED
Buzzard Roost 13C[b]	Chappels, S.C.	18	Combustion Turbine	RETIRED
Buzzard Roost 14C[b]	Chappels, S.C.	18	Combustion Turbine	RETIRED
Buzzard Roost 15C[b]	Chappels, S.C.	18	Combustion Turbine	RETIRED
Riverbend 8C[b]	Mt. Holly, N.C.	0	Combustion Turbine	RETIRED
Riverbend 9C[b]	Mt. Holly, N.C.	22	Combustion Turbine	RETIRED
Riverbend 10C[b]	Mt. Holly, N.C.	22	Combustion Turbine	RETIRED
Riverbend 11C[b]	Mt. Holly, N.C.	20	Combustion Turbine	RETIRED
Buck 7C[b]	Spencer, N.C.	25	Combustion Turbine	RETIRED
Buck 8C[b]	Spencer, N.C.	25	Combustion Turbine	RETIRED
Buck 9C[b]	Spencer, N.C.	12	Combustion Turbine	RETIRED
Dan River 4C[b]	Eden, N.C.	0	Combustion Turbine	RETIRED
Dan River 5C[b]	Eden, N.C.	24	Combustion Turbine	RETIRED
Dan River 6C[b]	Eden, N.C.	24	Combustion Turbine	RETIRED
Riverbend 4[a]	Mt. Holly, N.C.	94	Coal	RETIRED
Riverbend 5[a]	Mt. Holly, N.C.	94	Coal	RETIRED
Riverbend 6[c]	Mt. Holly, N.C.	133	Coal	RETIRED
Riverbend 7[c]	Mt. Holly, N.C.	133	Coal	RETIRED
Buck 5[c]	Spencer, N.C.	128	Coal	RETIRED
Buck 6[c]	Spencer, N.C.	128	Coal	RETIRED
Lee 1[d]	Pelzer, S.C.	100	Coal	4/15/2015
Lee 2[d]	Pelzer, S.C.	100	Coal	4/15/2015
Lee 3[e]	Pelzer, S.C.	170	Coal	1/1/2015
Total		2,037 MW		

Note a: 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.

Note b: 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.

Note c: The decision was made to retire Buck 5 & 6 and Riverbend 6 & 7 early on April 1, 2013. The original expected retirement date was April 15, 2015.

Note d: Lee Steam Units 1 through 3 are planned to be retired as indicated in the table.

Note e: The conversion of the Lee 3 coal unit to a natural gas unit is planned for April of 2015.

Operating License Renewal

Planned Operating License Renewal				
Plant & Unit Name	Location	Original Operating License Expiration	Date of Approval	Extended Operating License Expiration
Catawba Unit 1	York, SC	12/6/2024	12/5/2003	12/5/2043
Catawba Unit 2	York, SC	2/24/2026	12/5/2003	12/5/2043
McGuire Unit 1	Huntersville, NC	6/12/2021	12/5/2003	6/12/2041
McGuire Unit 2	Huntersville, NC	3/3/2023	12/5/2003	3/3/2043
Oconee Unit 1	Seneca, SC	2/6/2013	5/23/2000	2/6/2033
Oconee Unit 2	Seneca, SC	10/6/2013	5/23/2000	10/6/2033
Oconee Unit 3	Seneca, SC	7/19/2014	5/23/2000	7/19/2034
Bad Creek (PS)(1-4)	Salem, SC	N/A	8/1/1977	7//31/2027
Jocassee (PS) (1-4)	Salem, SC	N/A	9/1/1966	8/31/2016
Cowans Ford (1-4)	Stanley, NC	8/31/2008	Pending	8/31/2064 (Est)
Keowee (1&2)	Seneca, SC	N/A	9/1/1966	8/31/2016
Rhodhiss (1-3)	Rhodhiss, NC	8/31/2008	Pending	8/31/2064 (Est)
Bridge Water (1-3)	Morganton, NC	8/31/2008	Pending	8/31/2064 (Est)
Oxford (1&2)	Conover, NC	8/31/2008	Pending	8/31/2064 (Est)
Lookout Shoals (1-3)	Statesville, NC	8/31/2008	Pending	8/31/2064 (Est)
Mountain Island (1-4)	Mount Holly, NC	8/31/2008	Pending	8/31/2064 (Est)
Wylie (1-4)	Fort Mill, SC	8/31/2008	Pending	8/31/2064 (Est)
Fishing Creek (1-5)	Great Falls, SC	8/31/2008	Pending	8/31/2064 (Est)
Great Falls (1-8)	Great Falls, SC	8/31/2008	Pending	8/31/2064 (Est)
Dearborn (1-3)	Great Falls, SC	8/31/2008	Pending	8/31/2064 (Est)
Rocky Creek (1-8)	Great Falls, SC	8/31/2008	Pending	8/31/2064 (Est)
Cedar Creek (1-3)	Great Falls, SC	8/31/2008	Pending	8/31/2064 (Est)
Wateree (1-5)	Ridgeway, SC	8/31/2008	Pending	8/31/2064 (Est)
Gaston Shoals (3-6)	Blacksburg, SC	12/31/1993	6/1/1996	5/31/2036
Tuxedo (1&2)	Flat Rock, NC	N/A	N/A	N/A
Ninety Nine (1-6)	Blacksburg, SC	12/31/1993	6/1/1996	5/31/2036
Cedar Cliff (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Bear Creek (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Tennessee Creek (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Nantahala (1)	Topton, NC	2/28/2006	2/1/2012	1/31/2042

Planned Operating License Renewal cont.				
Plant & Unit Name	Location	Original Operating License Expiration	Date of Approval	Extended Operating License Expiration
Queens Creek (1)	Topton, NC	9/30/2001	3/1/2002	2/29/2032
Thorpe (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Tuckasegee (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Bryson City (1&2)	Whittier, NC	7/31/2005	7/1/2011	6/30/2041
Franklin (1&2)	Franklin, NC	7/31/2005	9/1/2011	8/31/2041
Mission (1-3)	Murphy, NC	7/31/2005	10/1/2011	9/30/2041

APPENDIX C: ELECTRIC LOAD FORECAST

Methodology

The Duke Energy Carolinas' spring 2013 forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2014 through 2028 and represent the needs of the following customer classes:

- Residential
- Commercial
- Industrial
- Other Retail
- Wholesale

Long-term electricity usage is determined by economic and demographic trends. The spring 2013 forecast was developed using industry-standard linear regression techniques, which relate electricity usage to such variables as income, electricity prices, industrial production index along with weather and population. DEC has used regression analysis since 1979 and this technique has yielded consistently reasonable results over the years.

The economic projections used in the spring 2013 forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of North Carolina and South Carolina.

The retail forecast consists of the three major classes: residential, commercial and industrial.

The residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electric price and appliance efficiencies. The usage per customer forecast is essentially flat through much of the forecast horizon, so most growth is primarily due to customer increases. The projected growth rate of residential sales in the spring 2013 forecast from 2014-2028 is 1.2%.

Commercial electricity usage changes with the level of regional economic activity, such as personal income or commercial employment, and the impact of weather. The three largest sectors in the Commercial class are offices, education and retail. Commercial is expected to be the fastest growing class, with a projected sales growth rate of 1.8%.

The industrial class forecast is impacted by the level of manufacturing output, exchange rates, electric prices and weather. The long term structural decline that has occurred in the Textile industry is expected to moderate in the forecast horizon, with an overall projected sales decline of 1.2%,

compared to an average decline of 7.2% from 1997-2012. 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 0.9% over the forecast horizon. Including all industrial classes, the overall sales growth rate of the total industrial class is 0.6% over the forecast horizon.

County population projections are obtained from the North Carolina Office of State Budget and Management as well as the South Carolina Budget and Control Board. These are then used to derive the total population forecast for the 51 counties that comprise the DEC service area.

Weather impacts are incorporated into the models by using Heating Degree Days and Cooling Degree Days with a base temperature of 65 degrees. The forecast of degree days is based on a 10-year average, which is updated every year.

Peak demands are forecasted by an econometric model where the key variables are:

- Degree Hours from 1pm - 5pm on Day of Peak
- Minimum Morning Degree Hours on Day of Peak
- Annual Weather Adjusted Sales

Assumptions

The primary long-term drivers of electricity growth are economic and demographic factors. The table below includes the historical and projected average annual growth rates of several key drivers from DEC's spring 2013 forecast.

	1992-2012	2012-2032
Real GDP	2.9%	3.0%
Real Income	3.1%	2.8%
Population	1.6%	1.0%

In addition to economic and demographic trends, the forecast also incorporates the expected impacts of utility sponsored energy efficient programs, as well as projected effects of electric vehicles and solar technology.

The residential forecast also uses the Energy Information Administration (EIA) appliance efficiency and saturation projections by Census regions, in an effort to more fully reflect the ongoing naturally occurring energy efficiency trends as well as government mandates. The utility-sponsored EE programs are over and above the naturally occurring trend.

Wholesale

Table C-1 below contains information concerning DEC's wholesale contracts. The description 'full' indicates that the Company provides all of the needs of the wholesale customer. 'Partial' refers to those customers where DEC only provides some of the customer's needs. 'Fixed' refers to a constant load shape.

For resource planning purposes, the contracts below are assumed to be renewed through the end of the planning horizon unless there is definitive knowledge the contract will not be renewed. The values in the table are net MW, i.e. they reflect projected loads after the buyer's own generation has been subtracted.

Table C-1 Wholesale Contracts

			Wholesale Contracts									
			Commitment (MW)									
Customer	Product	Term	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Concord	Partial Requirements	2009-2018	167	169	172	174	177	180	212	215	217	220
Dallas	Partial Requirements	2009-2028	11	11	11	12	12	12	12	12	13	13
Due West	Partial Requirements	2009-2018	2	2	2	2	2	2	2	2	2	2
Forest City	Partial Requirements	2009-2028	18	18	19	19	19	20	20	20	21	21
Greenwood	Full Requirements	2010-2018	53	53	54	55	56	57	58	58	59	60
Highlands	Full Requirements	2010-2029	9	9	9	9	9	9	9	9	10	10
Kings Mountain	Partial Requirements	2009-2018	21	21	21	22	22	22	30	30	30	31
Lockhart	Partial Requirements	2009-2018	50	50	51	52	53	54	75	76	77	78
Prosperity	Partial Requirements	2009-2028	2	2	2	2	2	2	3	3	3	3
Western Carolina	Full Requirements	2010-2021	6	6	6	6	6	6	6	6	6	6
Blue Ridge EMC	Full Requirements	2010-2031	225	229	233	237	241	245	249	253	257	261
Central	Partial Requirements	2013-2030	120	244	374	509	649	793	900	918	936	953
Haywood EMC	Full Requirements	2009-2021	23	23	23	24	24	24	25	25	25	26
NCEMC	Fixed Load Shape	2009-2038	72	72	72	72	72	72	72	72	72	72
NCEMC	Backstand	1985-2043	95	116	116	116	116	116	116	116	116	116
Piedmont EMC	Full Requirements	2010-2031	87	88	89	90	92	93	94	96	97	99
PMPA	Backstand	2014-2020	0	47	47	47	47	47	47	47	47	47
Rutherford EMC	Partial Requirements	2010-2031	185	189	204	208	212	217	221	226	230	235

Historical Values

Two major events occurred in the past decade that significantly impacted DEC sales. One was the recession of 2008-2009, which was the most severe since the Great Depression. The second is the ongoing re-structuring of the textile industry, which began in the late 1990s. The average growth rate in retail sales from 1997-2007, excluding textiles, was 2.2%. From 2007-2012, the average growth has been -0.1%, primarily due to the effects of the recession. In Tables C-2 & C-3 below the history of DEC customers and sales are shown. The values in Table C-3 are not weather adjusted.

Table C-2

Retail Customers (Thousands, Annual Average)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Residential	1,872	1,901	1,935	1,972	2,016	2,052	2,059	2,072	2,081	2,092
Commercial	307	313	319	325	331	334	333	334	336	339
Industrial	8	8	7	7	7	7	7	7	7	7
Other	11	12	13	13	13	14	14	14	14	14
Total	2,198	2,234	2,275	2,317	2,368	2,407	2,413	2,427	2,439	2,452

Table C-3

Electricity Sales (GWh Sold - Years Ended December 31)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Residential	23,947	25,150	26,108	25,816	27,459	27,335	27,273	30,049	28,323	26,279
Commercial	24,355	25,204	25,679	26,030	27,433	27,288	26,977	27,968	27,593	27,476
Industrial	24,764	25,209	25,495	24,535	23,948	22,634	19,204	20,618	20,783	20,978
Other	270	269	269	271	278	284	287	287	287	290
Total Retail	73,336	75,833	77,550	76,653	79,118	77,541	73,741	78,922	76,985	75,022
Wholesale	1,448	1,542	1,580	1,694	2,454	3,525	3,788	5,166	4,866	5,176
Total System	74,784	77,374	79,130	78,347	81,572	81,066	77,528	84,088	81,851	80,199

Results

A tabulation of the utility's forecasts for a 15-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 EE programs are shown below in Tables C-4 and C-6.

Load duration curves, with and without utility-sponsored EE programs, follow Tables C-4 and C-6, and are shown as Charts C-5 and C-7.

The values in these tables reflect the loads that Duke Energy Carolinas is contractually obligated to provide and cover the period from 2014 to 2028.

The forecast of the needs of the retail and wholesale customer classes from 2014-2028, not including the impact of DEC EE programs, projects a compound annual growth rate of 1.9% in the summer peak demand, while winter peaks are forecasted to grow at 1.9%. The forecasted compound annual growth rate for energy is 1.9% before energy efficiency program impacts are subtracted.

If the impacts of DEC EE programs are included, the projected compound annual growth rate for the summer peak demand is 1.5%, while winter peaks are forecasted to grow at a rate of 1.5%. The forecasted compound annual growth rate for energy is 1.5% after the impacts of EE are subtracted.

As a note, all of the loads and energy in the tables and charts below are at the generator.

Table C-4

Load Forecast without Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWh)
2014	18,443	17,718	93,566
2015	18,875	18,132	95,762
2016	19,328	18,553	98,023
2017	19,780	18,961	100,356
2018	20,231	19,376	102,773
2019	20,717	19,789	105,027
2020	21,067	20,143	106,904
2021	21,417	20,495	108,749
2022	21,776	20,842	110,634
2023	22,143	21,195	112,522
2024	22,525	21,563	114,471
2025	22,901	21,925	116,405
2026	23,280	22,299	118,371
2027	23,655	22,660	120,327
2028	24,017	23,015	122,243

Note: Table 8-C differs from these values due to a 150 MW firm sale in 2014 and a 47 MW PMPA backstand contract through 2020.

Chart C-5 Load Duration Curve without Energy Efficiency Programs

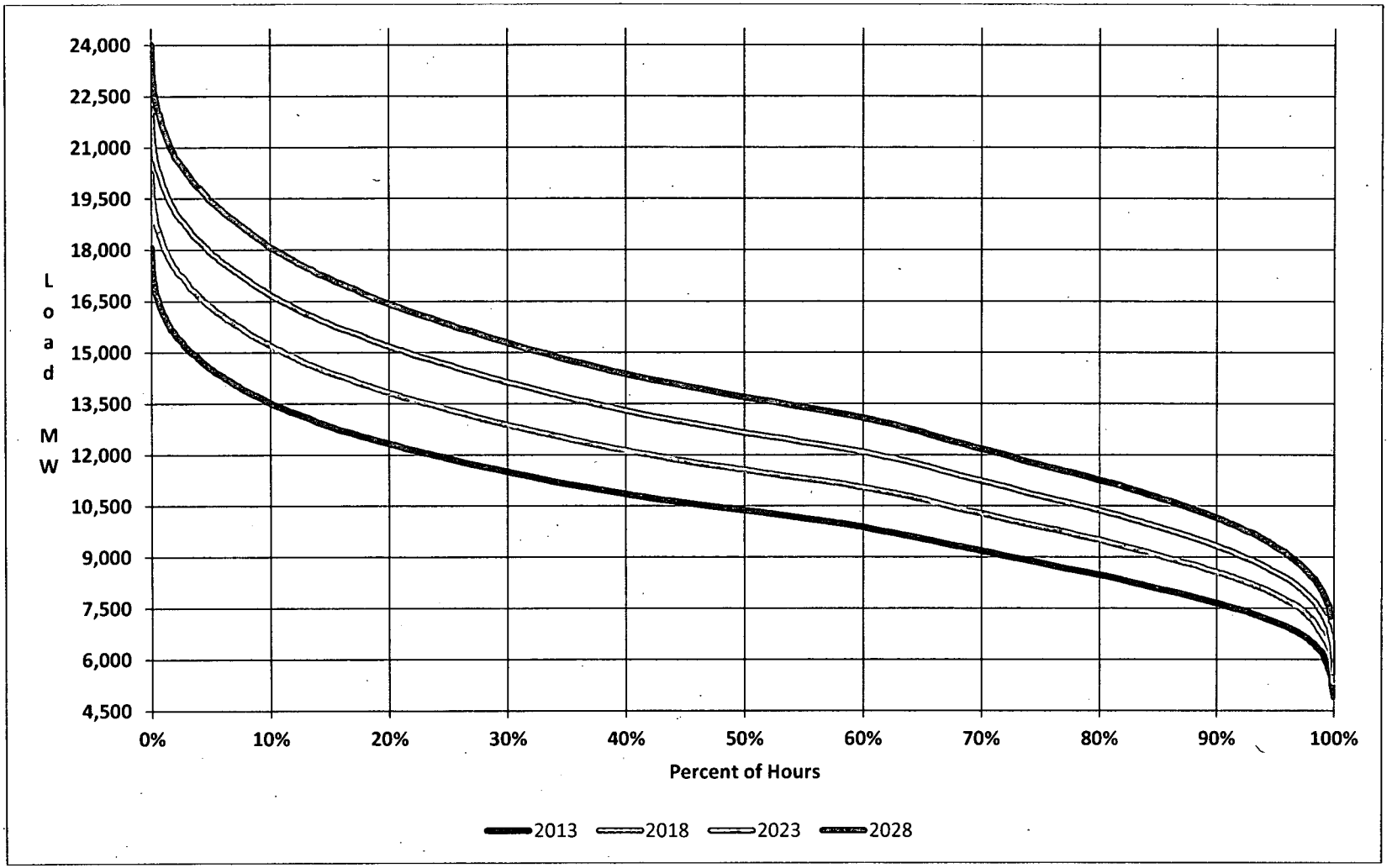
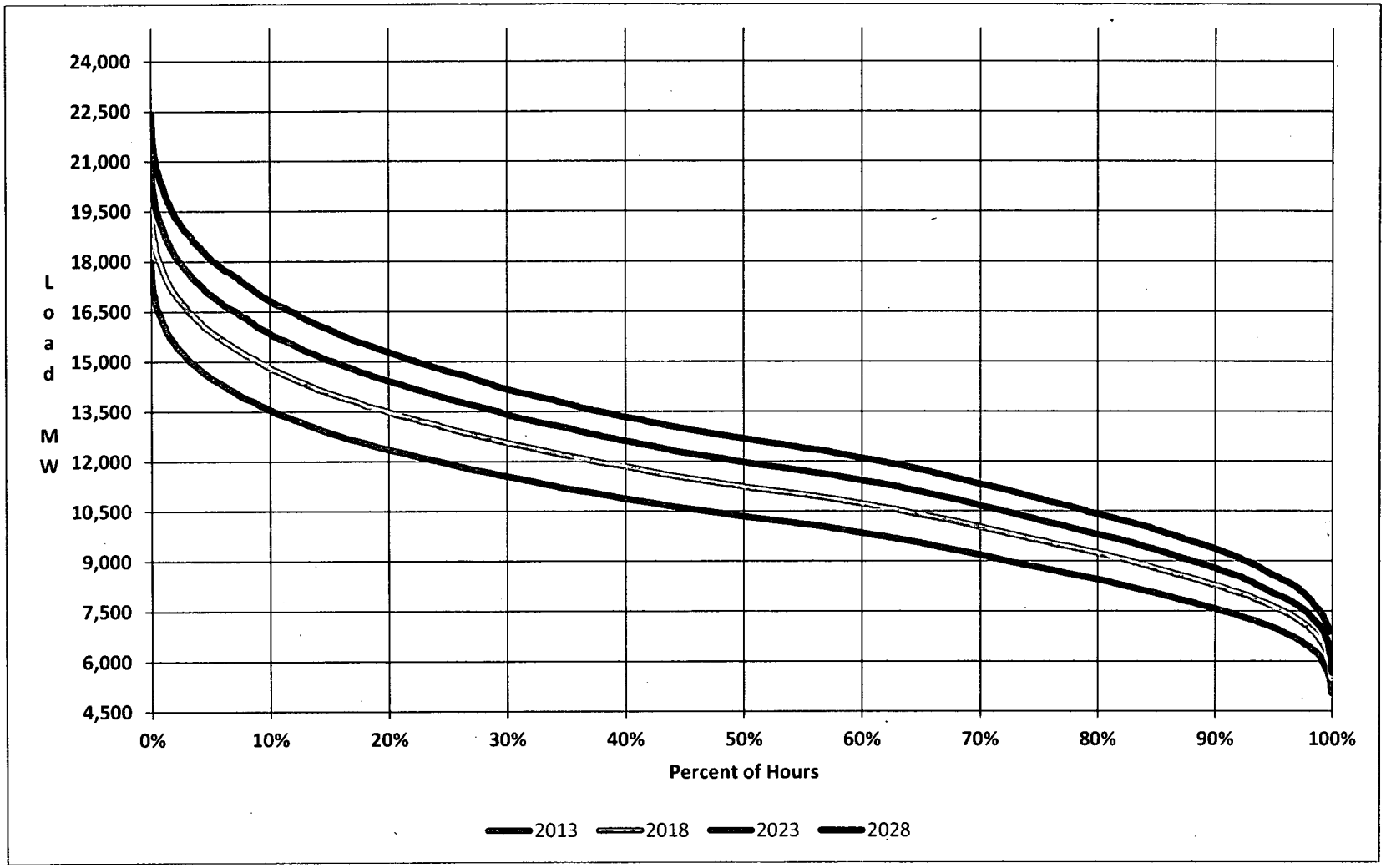


Table C-6
Load Forecast with Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWh)
2014	18,332	17,654	92,943
2015	18,691	18,009	94,721
2016	19,053	18,359	96,475
2017	19,398	18,685	98,226
2018	19,741	18,979	100,032
2019	20,117	19,304	101,678
2020	20,359	19,571	102,948
2021	20,598	19,834	104,187
2022	20,848	20,093	105,469
2023	21,104	20,359	106,748
2024	21,378	20,640	108,089
2025	21,643	20,913	109,418
2026	21,922	21,206	110,825
2027	22,209	21,496	112,294
2028	22,496	21,790	113,769

Note: Table 8-C differs from these values due to a 150 MW firm sale in 2014 and a 47 MW PMPA backstand contract through 2020.

Chart C-7 Load Duration Curve with Energy Efficiency Programs



APPENDIX D: ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT

Current Energy Efficiency and Demand-Side Management Programs

In May 2007, DEC filed its application for approval of Energy Efficiency and Demand Side Management 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 Public Service Commission of South Carolina (PSCSC) in May 2009.

DEC 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 and DSM programs that reduce peak demand (demand-side management or demand response programs and certain rate structure programs). Following are the EE and DSM programs currently available through DEC.

- Residential Energy Assessments Program
- Low Income Energy Efficiency and Weatherization Assistance Program
- Residential Neighborhood Program
- Energy Efficiency Education Program for Schools
- Residential Smart $aver® Program
- Appliance Recycling Program
- My Home Energy Report
- Residential Retrofit Pilot Program *(Closed to New Participants)*
- Smart Energy Now (SEN) Pilot *(Only Available in NC)*
- Smart $aver® for Non-Residential Customers
- Power Manager®
- Interruptible Power Service *(Closed to New Participants)*
- Standby Generator Control *(Closed to New Participants)*
- PowerShare®

A new portfolio filing with essentially the same set of programs was made in March 2013 in N.C. and Aug. 2013 in S.C. Pending approval of this new portfolio, a revised set of programs will be included in the 2014 IRP.

Energy Efficiency Programs

These programs are typically non-dispatchable 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 cumulative effects since the inception of these existing programs through the end of 2012 are reflected in the customer load forecast and summarized below. DEC's existing EE programs include:

- **Residential Energy Assessments Program**

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

  The Personalized Energy Report provides customers in single family dwellings with a customized report about how they use energy within their home. In addition, the customer receives compact fluorescent light bulbs (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 return it to DEC 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 document
  - An online offer to customers that have signed into DEC's Online Services (OLS) bill pay and view environment. Online participants complete their energy survey online and receive their PER online as a printable document

Personalized Energy Report			
As of:	Participants	Energy Savings (MWh)	Peak Demand (kW)
December 31, 2012	86,318	24,493	2,788

Online Home Energy Comparison Report			
As of:	Participants	Energy Savings (MWh)	Peak Demand (kW)
December 31, 2012	12,902	3,547	387

Home Energy House Call is a free in-home assessment designed to help 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 total home energy usage and pinpoint energy saving opportunities. The energy specialist explains how to improve heating and

cooling comfort levels, check for air leaks, examine insulation levels, review appliances and helps 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 part of the Home Energy House Call program, customers also receive an Energy Efficiency Starter Kit. At the request of the customer, the energy specialist will install the efficiency items included in the kit to allow the customer to begin saving immediately.

Home Energy House Call			
As of:	Participants	Energy Savings (MWh)	Peak Demand (kW)
December 31, 2012	21,293	20,732	3,846

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

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

Low Income Energy Efficiency and Weatherization Program			
As of:	Participants	Energy Savings (MWh)	Peak Demand (kW)
December 31, 2012	14,047	7,506	793

- **Residential Neighborhood Program**

  The Residential Neighborhood Program targets low income neighborhoods for direct installation of high impact EE measures such as CFLs, pipe and water heater wraps, low flow aerators and showerheads, Heating, Ventilation and Air Conditioning (HVAC) filters and air infiltration sealing, as well as energy efficiency education. As of Dec. 31, 2012 this program had not yet been implemented.

- **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.

Energy Efficiency Education for Schools Program			
As of:	Participants	Energy Savings (MWh)	Peak Demand (kW)
December 31, 2012	59,651	16,041	2,976

- **Residential Smart $aver® Program**

The Smart $aver® Program provides incentives to residential customers who purchase energy-efficient equipment. The program has three components: CFLs, high-efficiency air conditioning equipment and tune and seal measures.

Residential 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 utilized business reply cards and a web-based on-demand ordering tool where CFLs were shipped directly to the customer's home.

Residential Smart $aver® Program – Residential CFLs			
As of:	Participants (CFLs)	Energy Savings (MWh)	Peak Demand (kW)
December 31, 2012	20,740,362	892,622	94,349

Property Manager CFLs

This CFL program is designed to provide incentives to multi-family property managers to install CFLs in permanent, landlord-owned light fixtures. DEC will pay for the CFLs and the property manager will install CFLs into the permanent fixtures during their routine maintenance visits and provide tracking for each unit and the number of bulbs installed.

Residential Smart $aver® Program – Property Manager CFLs			
As of:	Participants (CFLs)	Energy Savings (MWh)	Peak Demand (kW)
December 31, 2012	708,991	30,375	3,190

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 replacement systems in existing homes.

Residential Smart $aver® Program -- HVAC			
As of:	Participants	Energy Savings (MWh)	Peak Demand (kW)
December 31, 2012	37,383	37,032	7,835

Tune and Seal 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 is a new program and has not been previously offered in any of DEC's jurisdictions.

Residential Smart $aver® Program -- Tune and Seal			
As of:	Participants	Energy Savings (MWh)	Peak Demand (kW)
December 31, 2012	23	11	3

- **Appliance Recycling Program**

This is a program to incentivize households to remove old inefficient refrigerators and freezers and have those units properly recycled.

Appliance Recycling Program			
As of:	Participants	Energy Savings (MWh)	Peak Demand (kW)
December 31, 2012	1,990	3,286	610

- **My Home Energy Report**

The purpose of this program is to provide comparative usage data for similar residences in the same geographic area to motivate customers to better manage and reduce energy usage. The program assists residential customers in assessing their energy usage and provides recommendations for more efficient use of energy in their homes. The program also helps to identify those customers who could benefit most by investing in new energy efficiency measures, undertaking more energy efficient practices and participating in DEC programs.

My Home Energy Report Program			
As of:	Participants	Capability (MWh)	Summer Capability (kW)
December 31, 2012	702,215	160,021	33,857

- **Residential Retrofit Pilot Program (*Closed to New Participants*)**

  The Residential Retrofit pilot program is designed to assist residential customers in assessing their energy usage. The program is also designed 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.

Residential Retrofit Pilot Program			
As of:	Participants	Energy Savings (MWh)	Peak Demand (kW)
December 31, 2012	94	410	68

- **Smart Energy Now (SEN) Pilot (*Only Available in N.C.*)**

  The SEN pilot program 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.

Smart Energy Now Pilot Program			
As of:	Participants	Energy Savings (MWh)	Peak Demand (kW)
December 31, 2012	70	14,108	2,649

- **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.

Non-Residential Smart $aver® Program			
As of:	Participants	Energy Savings (MWh)	Peak Demand (kW)
December 31, 2012	1,342,909	617,614	103,225

Demand Side Management Programs

DEC's current DSM programs will be presented in two sections; Demand Response Direct Load Control Programs and Demand Response Interruptible Programs and Related Rate Tariffs.

Demand Response – Direct Load Control Programs

These programs can be dispatched by the utility and have the highest level of certainty. DEC's current direct load control curtailment programs are:

- **Power Manager®** - The Power Manager® program is a residential direct load control program that allows DEC, through the installation of load control devices at the customer's premise, to remotely control residential central air conditioning.

  Participants receive billing credits during the billing months of July through October in exchange for allowing DEC the right to cycle their central air conditioning systems and, additionally, to interrupt the central air conditioning when the Company has capacity needs.

  The program provides DEC with the ability to reduce and shift peak loads, thereby enabling a corresponding deferral of new supply-side peaking generation and enhancing system reliability.

  Participating customers are impacted by (1) the installation of load control equipment at their residence, (2) load control events which curtail the operation of their air conditioning unit for a period of time each hour, and (3) the receipt of bill credits from DEC in exchange for allowing DEC the ability to control their electric equipment.

Power Manager Statistics		
As of:	Participants	Summer Capability (MW)
December 31, 2012	185,043	280.4

The following table shows Power Manager® program activations that were not for testing purposes from June 1, 2011 through June 30, 2013.

Power Manager® Activations			
Start Time	End Time	Duration (Minutes)	MW Load Reduction*
June 21, 2011 – 2:30 PM	June 21, 2011 – 5:00 PM	150	101
July 11, 2011 – 2:30 PM	July 11, 2011 – 6:00 PM	210	101
July 13, 2011 – 2:30 PM	July 13, 2011 – 6:00 PM	210	102
July 20, 2011 – 2:30 PM	July 20, 2011 – 5:00 PM	150	108
July 21, 2011 – 2:30 PM	July 21, 2011 – 5:00 PM	150	115
July 29, 2011 – 2:30 PM	July 29, 2011 – 5:00 PM	150	110
August 2, 2011 – 3:30 PM	August 2, 2011 – 6:00 PM	150	115
June 29, 2012 – 2:30 PM	June 29, 2012 – 5:00 PM	150	152
July 9, 2012 – 1:30 PM	July 9, 2012 – 5:00 PM	210	113
July 17, 2012 – 2:30 PM	July 17, 2012 – 5:00 PM	150	141
July 26, 2012 – 2:30 PM	July 26, 2012 – 6:00 PM	210	143
July 27, 2012 – 1:30 PM	July 27, 2012 – 4:00 PM	150	152

* *MW Load Reduction is the average load reduction "at the generator" over the event period for full clock hours.*

Demand Response – Interruptible Programs 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 rate structure curtailment programs include:

- **Interruptible Power Service (IS)** (North Carolina Only) - Participants agree contractually to reduce their electrical loads to specified levels upon request by DEC. If customers fail to do so during an interruption, they receive a penalty for the increment of demand exceeding the specified level.

IS Statistics		
As of:	Participants	Summer Capability (MW)
December 31, 2012	63	128.5

The following table shows IS program activations that were not for testing purposes from June 1, 2011 through June 30, 2013.

IS Activations			
Start Time	End Time	Duration (Minutes)	MW Load Reduction*
June 1, 2011 – 1:00 PM	June 1, 2011 – 6:00 PM	300	156
July 12, 2011 – 1:00 PM	July 12, 2011 – 5:00 PM	240	133

**MW Load Reduction is the average load reduction "at the generator" over the event period.*

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

SG Statistics		
As of:	Participants	Summer Capability (MW)
December 31, 2012	87	44.0

The following table shows SG program activations that were not for testing purposes from June 1, 2011 through June 30, 2013.

SG Activations			
Start Time	End Time	Duration (Minutes)	MW Load Reduction*
June 1, 2011 – 1:00 PM	June 1, 2011 – 6:00 PM	300	55
July 12, 2011 – 1:00 PM	July 12, 2011 – 5:00 PM	240	45

**MW Load Reduction is the average load reduction "at the generator" over the event period.*

- **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® Mandatory Statistics		
As of:	Participants	Summer Capability (MW)
December 31, 2012	169	366.4

The following table shows PowerShare® Mandatory program activations that were not for testing purposes from June 1, 2011 through June 30, 2013.

PowerShare® Mandatory Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction***
June 1, 2011 – 1:00 PM	June 1, 2011 – 6:00 PM	300	334
July 12, 2011 – 1:00 PM	July 12, 2011 – 5:00 PM	240	339

**MW Load Reduction is the average load reduction "at the generator" over the event period.*

- PowerShare® Generator: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail (i.e. transfer to their on-site generator) during utility-initiated emergency events and their performance during monthly test hours. Participants also receive energy credits for the load curtailed during events.

PowerShare® Generator Statistics		
As of:	Participants	Summer Capability (MW)
December 31, 2012	9	13.4

The following table shows PowerShare® Generator program activations that were not for testing purposes from June 1, 2011 through June 30, 2013.

PowerShare® Generator Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction***
June 1, 2011 – 1:00 PM	June 1, 2011 – 6:00 PM	300	17
July 12, 2011 – 1:00 PM	July 12, 2011 – 5:00 PM	240	13

**MW Load Reduction is the average load reduction "at the generator" over the event period.*

- PowerShare® Voluntary: Enrolled customers will be notified of pending emergency

or economic events and can log on to a website 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. Since this is a voluntary event program, no capacity benefit is recognized for this program and no capacity incentive is provided. The statistics values below represent participation in PowerShare® Voluntary only and do not double count the participants in PowerShare® Mandatory that also participate in PowerShare® Voluntary.

PowerShare® Voluntary Statistics		
As of:	Participants	Summer Capability (MW)
December 31, 2012	6	N/A

The following table shows PowerShare® Voluntary program activations that were not for testing purposes from June 1, 2011 through June 30, 2013.

PowerShare® Voluntary Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction***
June 1, 2011 – 1:00 PM	June 1, 2011 – 9:00 PM	480	2
June 2, 2011 – 2:00 PM	June 2, 2011 – 8:00 PM	360	16
July 20, 2011 – 1:00 PM	July 20, 2011 – 7:00 PM	360	2
July 21, 2011 – 1:00 PM	July 21, 2011 – 7:00 PM	360	2
July 22, 2011 – 11:00 AM	July 22, 2011 – 4:00 PM	300	4
August 3, 2011 – 2:00 PM	August 3, 2011 – 7:00 PM	300	2

**MW Load Reduction is the average load reduction "at the generator" over the event period.*

- 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.

PowerShare® CallOption Statistics		
As of:	Participants	Summer Capability (MW)
December 31, 2012	1	0.2

The following table shows PowerShare® CallOption program activations that were not for testing purposes from June 1, 2011 through June 30, 2013.

PowerShare® CallOption Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction***
July 27, 2012 – 1:00 PM	July 27, 2012 – 9:00 PM	480	0.2

**MW Load Reduction is the average load reduction "at the generator" over the event period.*

- PowerShare® CallOption 200: This new, high involvement CallOption is targeted at customers with very flexible load and curtailment potential of up to 200 hours of economic load curtailment each year. This option will function essentially in the same manner as the Company's other CallOption offers. However, customers who participate will experience considerably more requests for load curtailment for economic purposes. Participants will remain obligated to curtail load during up to 5 emergency events.

  The program is not available for customer participation until January 1, 2014.

The table below incorporates December 31, 2012 participation levels for demand response programs and the capability of these programs projected for the summer of 2013.

DSM Program Participation and Capability

DSM Program Name	Participation as of 12/31/12	2013 Estimated Summer IRP Capability (MW)
IS	63	117
SG	87	40
PowerShare® Mandatory	169	375
PowerShare® Generator	9	14
PowerShare® Voluntary	6	N/A
PowerShare® CallOption		
-- Level 0/5	0	0
-- Level 5/5	0	0
-- Level 10/5	0	0
-- Level 15/5	1	0
-- Level 200*	0	0
Power Manager®	185,043	305
Total	185,378	851

** PowerShare® CallOption Level 200 will be available for participation on 1/1/2014.*

- **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 DEC's 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.

The projected impacts from these programs are included in the assessment of generation needs.

Summary of Prospective Program Opportunities

A new portfolio filing with essentially the same set of programs was made in March 2013 in NC and August 2013 in SC. Pending approval of this new portfolio a revised set of programs will be included in the 2014 IRP. Included in this new portfolio filing are enhancements to existing programs along with the following program that has not been previously offered:

- **Energy Management and Information Services Pilot**
  This pilot is designed to provide qualified commercial and industrial customers with a systematic approach to reduce energy and peak demand. The company will provide the customer with an energy management and information system and an on-site energy assessment to help the customer identify and implement a bundle of low cost operational and maintenance-based energy efficiency measures.

Future EE and DSM programs

In addition, DEC is continually seeking to enhance its EE and DSM portfolio by: (1) adding new or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new measurement and verification (M&V) results, and (3) other EE pilots. Estimates of the impacts of these yet-to-be-developed programs have been included in this year's analysis of generation needs.

EE and DSM Program Screening

The Company uses the DSMore model to evaluate the costs, benefits, and risks of EE and DSM programs and measures. DSMore is a financial analysis tool designed to estimate of the capacity and energy values of EE and DSM 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 EE and DSM 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 and demand side management 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 the costs incurred by the utility 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 cost-effective DSM and EE programs and indicate the likelihood that customers will participate.

Energy Efficiency and Demand-Side Management Program Forecasts

In 2011, DEC commissioned a new EE market potential study to obtain new estimates of the technical, economic and achievable potential for EE savings within the DEC service area. The final report was prepared by Forefront Economics Inc. and H. Gil Peach and Associates, LLC and was completed on February 23, 2012 and included an achievable potential for planning year 5 and an economic potential for planning year 20.

In early 2013, this market potential study was updated by Forefront Economics Inc. to estimate the achievable potential on an annual basis throughout the 20 year horizon in order to align the forecast methodology with the integrated resources planning being done for DEP.

The results of this achievable potential were blended together with the DEC forecast for the 5-year planning horizon to create an overall forecast that used a similar methodology to the 2012 DEC IRP for the first 5 years. For years 6 through 20, DEC used methodology that was more like that used by DEP in its 2012 IRP.

The Forefront study results are suitable for IRP purposes and use in long-range system planning models. This study is also expected to help inform utility program planners regarding the extent of EE opportunities and to provide broadly defined approaches for acquiring savings. This study did not, however, attempt to closely forecast EE achievements in the short-term or from year to year. Such an annual accounting is highly sensitive to the nature of programs adopted, the timing of the introduction of those programs, and other factors. As a result, it was not designed to provide detailed specifications and work plans required for program implementation. This study provides part of the picture for planning EE programs. Fully implementable EE program plans are best developed considering this study along with the experience gained from currently running programs, input from DEC program managers and EE planners, and with the possible assistance of implementation contractors.

The table below provides the base case projected load impacts of all DEC EE and DSM programs implemented since the approval of the save-a-watt recovery mechanism in 2009. These load impacts were included in the base case IRP analysis. Note that some years may not sum to the total due to rounding. The Company assumes total EE savings will continue to grow on an annual basis throughout the planning period, 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 MW load impacts from the DSM programs are based upon the Company's continuing, as well as new, DSM programs. This table does not include historical EE program savings since the inception of the EE programs in 2009 through the end of 2012, which accounts for approximately an additional 1,828 GWh of energy savings and 257 MW of summer peak demand savings. The projections also do not include savings from DEC's proposed Integrated Voltage-VAR Control program which will be discussed later in this document.

Base Case Load Impacts of EE and DSM Programs

Year	EE Program Savings		DSM Program Summer Peak MW Savings					Total Summer Peak MW Savings
	Annual MWh Energy	Summer Peak MW	IS	SG	PowerShare	Power Manager	Total DSM	
2013	435,988	40	117	40	389	305	851	891
2014	810,708	111	101	32	427	350	911	1,022
2015	1,271,350	184	96	29	459	399	983	1,167
2016	1,824,144	275	92	26	487	409	1,014	1,289
2017	2,436,079	382	87	24	515	411	1,037	1,419
2018	3,046,042	490	83	21	545	411	1,061	1,551
2019	3,654,035	600	83	21	545	411	1,061	1,661
2020	4,260,057	708	83	21	545	411	1,061	1,769
2021	4,864,109	819	83	21	545	411	1,061	1,880
2022	5,466,189	929	83	21	545	411	1,061	1,990
2023	6,084,580	1,040	83	21	545	411	1,061	2,101
2024	6,682,978	1,110	83	21	545	411	1,061	2,171
2025	7,290,633	1,219	83	21	545	411	1,061	2,280
2026	7,801,137	1,318	83	21	545	411	1,061	2,379
2027	8,267,015	1,404	83	21	545	411	1,061	2,465
2028	8,683,743	1,477	83	21	545	411	1,061	2,538

DEC's 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 EE and DSM programs, subject to the results of ongoing collaborative workshops and appropriate regulatory treatment.

However, pursuing EE and DSM initiatives is not expected to meet the incremental demand for electricity. DEC still envisions the need to secure additional generation, as well as cost-effective renewable generation, but the EE and DSM programs offered by DEC will address a significant portion of this need if such programs perform as expected.

EE Savings Variance since last IRP

The EE savings forecast of MWh energy is different from the forecast presented in the 2012 DEC IRP in the following ways:

- The 2013 IRP is based on an updated forecast of DEC's 5 year planning horizon for the period of 2013-17.
- The 2013 IRP uses analysis performed by Forefront Economics, Inc. to estimate the long-range EE savings based on achievable potential rather than the straight line estimation used by DEC in the 2012 IRP.

The implementation of these two changes in methodology results in a base case MWh forecast that is higher than that presented in the 2012 DEC IRP, however, the overall shape of the forecast changes from a straight line expectation in 2012 to a curve that shows a gradual decrease in the amount of incremental achievable MWh beginning in about 2025.

High EE Savings Projection

DEC also prepared a high EE savings projection designed to meet the following Energy Efficiency Performance Targets for five years, as set forth in the December 8, 2011 Settlement Agreement between Environmental Defense Fund, the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy, and Duke Energy Corporation, Progress Energy, Inc., and their public utility subsidiaries Duke Energy Carolinas LLC and Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.

- An annual savings target of 1% of the previous year's retail electricity sales beginning in 2015; and
- A cumulative savings target of 7% of retail electricity sales over the five year time period of 2014 through 2018.

For the purposes of this IRP, the high EE savings projection is being treated as a resource planning sensitivity that will also serve as an aspirational target for future EE plans and programs. The high EE savings projections are well beyond the level of savings attained by DEC in the past and higher than the forecasted savings contained in the new market potential study. The effort to meet them will require a substantial expansion of DEC's current Commission-approved EE portfolio. New programs and measures must be developed, approved by regulators, and implemented within the next few years. More importantly, significantly higher levels of customer participation must be generated. Additionally, flexibility will be required in operating existing programs in order to quickly adapt to changing market conditions, code and standard changes, consumer demands, and emerging technologies.

At this time there is too much uncertainty in the development of new technologies that will impact future programs and/or enhancements to existing programs, as well as in the ability to secure high levels of customer participation, to risk using the high EE savings projection in the base assumptions for developing the 2013 IRP. However, the high EE savings forecast was included in the Environmental Focus Scenario. DEC expects that as steps are made over time toward actually achieving higher levels of program participation and savings, then the EE savings forecast used for integrated resource planning purposes will continue to be revised in future IRP's to reflect the most realistic projection of EE savings.

Programs Evaluated but Rejected

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

Looking to the Future

- **Grid Modernization (Smart Grid Impacts)**
  Duke Energy is pursuing implementation of grid modernization throughout the enterprise with a vision of creating a sustainable energy future for our customers and our business by being a leader of innovative approaches that will modernize the grid.

  DEC is reviewing an Integrated Volt-VAR Control (IVVC) project that will better manage the application and operation of voltage regulators (the Volt) and capacitors (the VAR) on the DEC distribution system. In general, the project tends to optimize the operation of these devices, resulting in a "flattening" of the voltage profile across an entire circuit, starting at the substation and continuing out to the farthest endpoint on that circuit. This flattening of the voltage profile is accomplished by automating the substation level voltage regulation and capacitors, line capacitors and line voltage regulators while integrating them into a single control system. This control system continuously monitors and operates the voltage regulators and capacitors to maintain the desired "flat" voltage profile. Once the system is operating with a relatively flat voltage profile across an entire circuit, the resulting circuit voltage at the substation can then be operated at a lower overall level. Lowering the circuit voltage at the substation results in an immediate reduction of system loading. Through application of IVVC and reduced system voltage, DEC is thereby reducing load and system demand.

  The deployment of an IVVC program for DEC is anticipated to take approximately 5 years following project approval. This IVVC program is projected to reduce future distribution system demand by 0.20% in 2015, 0.4% in 2016, 0.6% in 2017, 0.8% in 2018 and 1.00% in 2019 and following years.

APPENDIX E: FUEL SUPPLY

Duke Energy Carolinas' current fuel usage consists primarily of coal and uranium. Oil and gas have traditionally been used for peaking generation, but natural gas has begun to play a more important role in the fuel mix due to lower pricing and the addition of the Buck and Dan River Combined Cycle plants. These additions will further increase the importance of gas to the Company's generation portfolio. A brief overview and issues pertaining to each fuel type are discussed below.

Natural Gas

Following a tumultuous year (2012) for North American gas producers, 2013 is signaling a return to market stability. Near term prices have recovered from their sub $2/MMBtu lows to settle into the $3.50 - $4.00 range. Inventories are back in neutral territory, gas directed rig counts remain at 18 year lows and yet, the size of the low cost resource base continues to expand. Looking forward, the gas market is expected to remain relatively stable and the improving economic picture will allow the supply / demand balance to tighten and prices to continue to firm at sustainable levels. New gas demand from the power sector is likely to get a small boost between now and 2015 from coal retirements which are tied to the implementation of the Environmental Protection Agency (EPA) MATS rule covering mercury and acid gasses. This increase is expected to be followed by new demand in the industrial and LNG export sectors which both ramp up in the 2016 – 2020 timeframe.

The long term fundamental gas price outlook is little changed from the 2012 forecast even though it includes higher overall demand. The North American gas resource picture is a story of unconventional gas production dominating the gas industry. Shale gas now accounts for about 38% of natural gas production today, rising to over half by 2019.

The US power sector still represents the largest area of potential new demand, but growth is expected to be uneven. After absorbing about 8.8 bcfd of new gas demand tied to coal displacements in the power dispatch in 2012, higher gas prices have reversed the trend. Looking forward, direct price competition is expected between gas and coal on the margin. A 2015 bump in gas demand is expected when EPA's MATS rule goes into effect and utilities retire a significant amount of coal (~38 GW's in this outlook).

Coal

On average, the 2013 Duke fundamental outlook for coal prices is lower than the 2012 outlook, with the exception of Central Appalachian (CAPP) sourced coal which is higher in the near-term primarily as a result of deterioration in mine productivity. Since 2008, Central Appalachian underground mine productivity (tons per man-hour) has declined by 28%, surface mine productivity by 23%; this combination equates to roughly a $5 per ton increase in labor costs alone.

Coal burned in power generation accounts for roughly 80% of all domestic coal production, export steam coal 10%, metallurgical coal for both domestic consumption and export 8%, with the balance consumed in industrial and commercial applications. The coal forecast assumes a long-term decline in power generation from coal following the introduction of the assumed carbon tax in 2020. Exports of metallurgical coals from the East (CAPP and NAPP) are projected to remain constant while export steam coal grows steadily. This growth assumption is driven by superior productivity in Illinois Basin (ILB) and Powder River Basin (PRB) with delivery of ILB to Atlantic markets via the Gulf of Mexico and delivery of PRB to the Pacific markets via terminals planned for Washington state and British Columbia.

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. Near-term requirements not met by long-term supply contracts have been and are expected to be fulfilled with spot market purchases.

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.

APPENDIX F: SCREENING OF GENERATION ALTERNATIVES

The Company screens generation technologies prior to performing detailed analysis in order to develop a manageable set of possible generation alternatives. Generating technologies are screened from both a technical perspective, as well as an economic perspective. In the technical screening, technology options are reviewed to determine technical limitations, commercial availability issues and feasibility in the Duke Energy Carolinas service territory. Economic screening is performed using a relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves. The technologies must be viable from both technically and economically in order to be passed on to the detailed analysis phase of the IRP process.

Technical Screening

The first step in the Company's supply-side screening process for the IRP is 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 basis 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 energy storage technologies (Lead Acid, Li-ion, Sodium Ion, Zinc Bromide, Fly Wheels, Pumped Storage, etc) remain relatively expensive, as compared to conventional generation sources, but the benefits to a utility such as the ability to shift load and firm renewable generation are obvious. Research, development, and demonstration continue within Duke Energy Corporation. Duke Energy Generation Services has installed a 36 MW advanced acid lead battery at the Notrees wind farm in Texas that began commercial operation in December 2012. Duke Energy has installed a 75 kW battery in Indiana which is integrated with solar generation and electric vehicle charging stations. Duke Energy also has other storage system tests within its Envision Energy demonstration in Charlotte, which includes two Community Energy Storage (CES) systems of 24 kW, and three substation demonstrations less than 1 MW each.

- 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 modular nuclear reactors (SMR) are generally defined as having capabilities of less than 300 MW. In 2012, U.S. Department of Energy (DOE) solicited bids for companies to participate in a small modular reactor grant program intending to "promote the accelerated commercialization of SMR technologies to help meet the nation's economic energy security and climate change objectives." The focus of the grant is the first-of-a-kind engineering associated with NRC design certification and licensing efforts in order to demonstrate the ability to achieve NRC design certification and licensing to support SMR plant deployment on a domestic site by 2022. The grant was awarded to Babcock & Wilcox (B&W) who will lead the effort in partnership with TVA and Bechtel. It is estimated that this project may lead to the development of "plug and play" type nuclear reactor applications that are about one-third the size of current reactors. These are expected to become commercially available around 2022. Duke will be monitoring the progress of the SMR project for potential consideration and evaluation for future resource planning.

- 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 swine waste digesters remain relatively expensive and are often faced with operational and/or permitting challenges. Research, development, and demonstration continue, but these technologies remain generally too expensive or face obstacles that make them impractical energy choices outside of specific mandates calling for use of these technologies.

- Off-shore wind, although demonstrated on a utility scale and commercially available, is not a widely applied technology and not easily permitted. This technology remains expensive and has yet to actually be constructed anywhere in the United States. Currently, the Cape Wind project in Massachusetts has been approved with assistance from the federal government but has not begun construction. The Company is a contributor to the DOE-sponsored COWICS.

Economic Screening

The Company screens all technologies using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves. The screening within each general class (Baseload,

Peaking/Intermediate, and Renewables), as well as the final screening across the general classes, uses 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 includes the total costs associated with owning and maintaining a technology type over its lifetime and computes a levelized $/kW-year value over a range of capacity factors. 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 technologies 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.

The Company selected the technologies listed below for the screening curve analysis. While EPA's MATS and Greenhouse Gas (GHG) New Source regulations may effectively preclude new coal-fired generation, Duke Energy Carolinas has included SCPC and IGCC technologies with carbon CCS of 800 pounds/net MWH as options for base load analysis consistent with the proposed EPA New Source Performance Standard (NSPS) rules. Additional detail on the expected impacts from EPA regulations to new coal-fired options is included in Appendix F.

- Base load – 825 MW Supercritical Pulverized Coal with CCS
- Base load – 618 MW IGCC with CCS
- Base load – 2 x 1,117 MW Nuclear units (AP1000)
- Base load – 680 MW – 2x1 Combined Cycle (Inlet Chiller and Fired)
- Base load – 843 MW – 2x1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Base load – 1,275 MW – 3x1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Peaking/Intermediate – 174 MW 4 x LM6000 CTs
- Peaking/Intermediate – 805 MW 4 x 7FA.05 CTs
- Renewable – 150 MW Wind - On-Shore
- Renewable – 25 MW Solar PV

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 internal Departments: Duke Energy's New Generation Project Development, Emerging Technologies, and Analytical Engineering. The following external sources may also be utilized: proprietary third-party engineering studies, the EPRI Technology Assessment Guide (TAG®), and EIA. In addition, fuel and operating cost estimates are developed internally by Duke Energy, or from other sources such as those mentioned above, or a combination of the two. Electric Power

Research Institute (EPRI) information or other 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 that capital, O&M and fuel costs and other parameters are current and include similar scope across the technologies being screened. The supply-side screening analysis uses 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 detailed analysis (discussed in Appendix A). Screening curves were developed for each technology to show the economics with and without carbon costs.

Screening Results

The results of the screening within each category are shown in the figures below. Results of the baseload screening show that combined cycle generation is the least-cost baseload resource. With lower gas prices, larger capacities and increased efficiency, combined cycle units have become more cost-effective at higher capacity factors. Supercritical pulverized coal generation closes the gap with combined cycle generation only if carbon capture sequestration and CO_2 costs are excluded. The baseload curves also show that nuclear generation may be a cost effective option at high capacity factors with CO_2 costs included.

The peaking/intermediate technology screening included F-frame combustion turbines and fast start aero-derivative combustion turbines. The screening curves show the F-frame CTs to be the most economic peaking resource unless there is a special application that requires the fast start capability of the aero-derivative CTs.

The renewable screening curves show solar is a more economic alternative than wind generation. Solar and wind projects are technically constrained from achieving high capacity factors making them unsuitable for intermediate or baseload duty cycles. Solar projects, like wind, are not dispatchable and therefore less suited to provide consistent peaking capacity. Aside from their technical limitations, solar and wind technologies are not currently economically competitive generation technologies without state and federal subsidies. These renewable resources do play an important role in meeting the Company's NC REPS requirements.

The screening curves are useful for comparing costs of resource types at various capacity factors but cannot be utilized for determining a long-term resource plan because future units must be optimized with an existing system containing various resource types. In the quantitative analysis phase, the Company further evaluates those technologies from each of the three general categories screened which had the lowest levelized busbar cost for a given capacity factor range within each of these categories.

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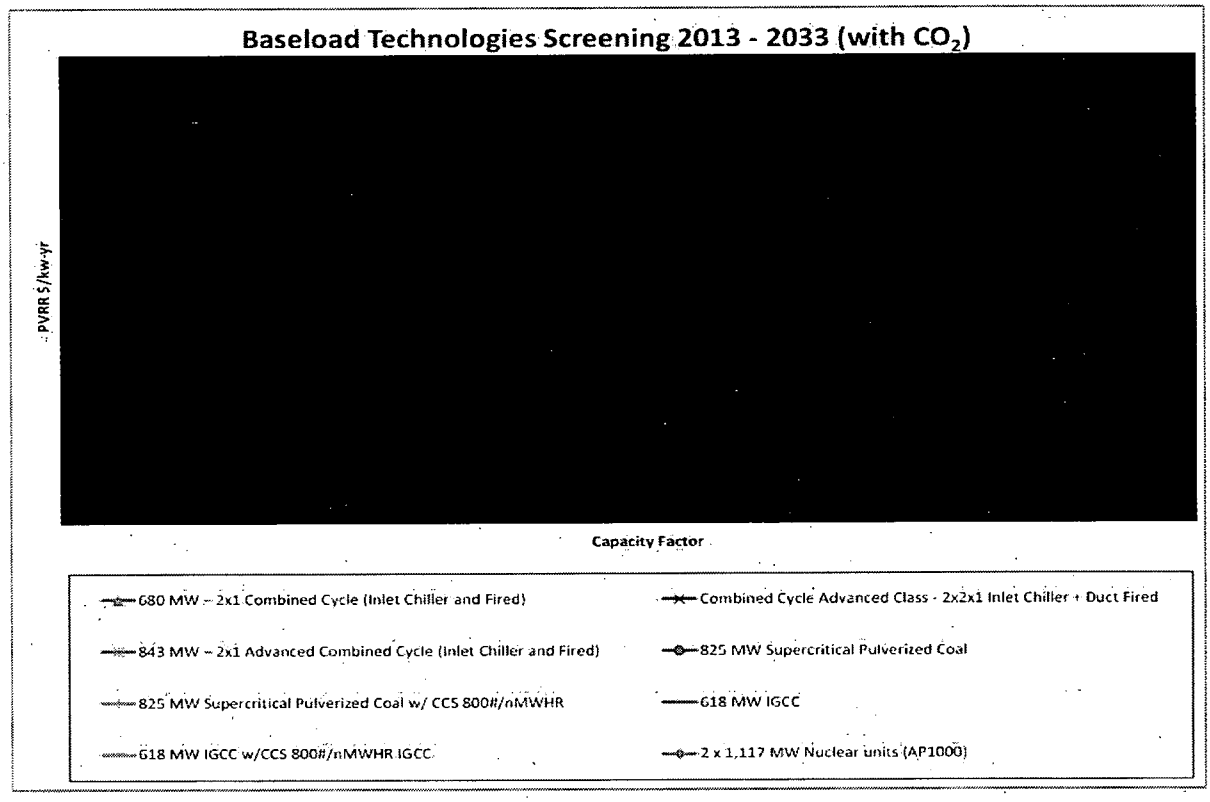

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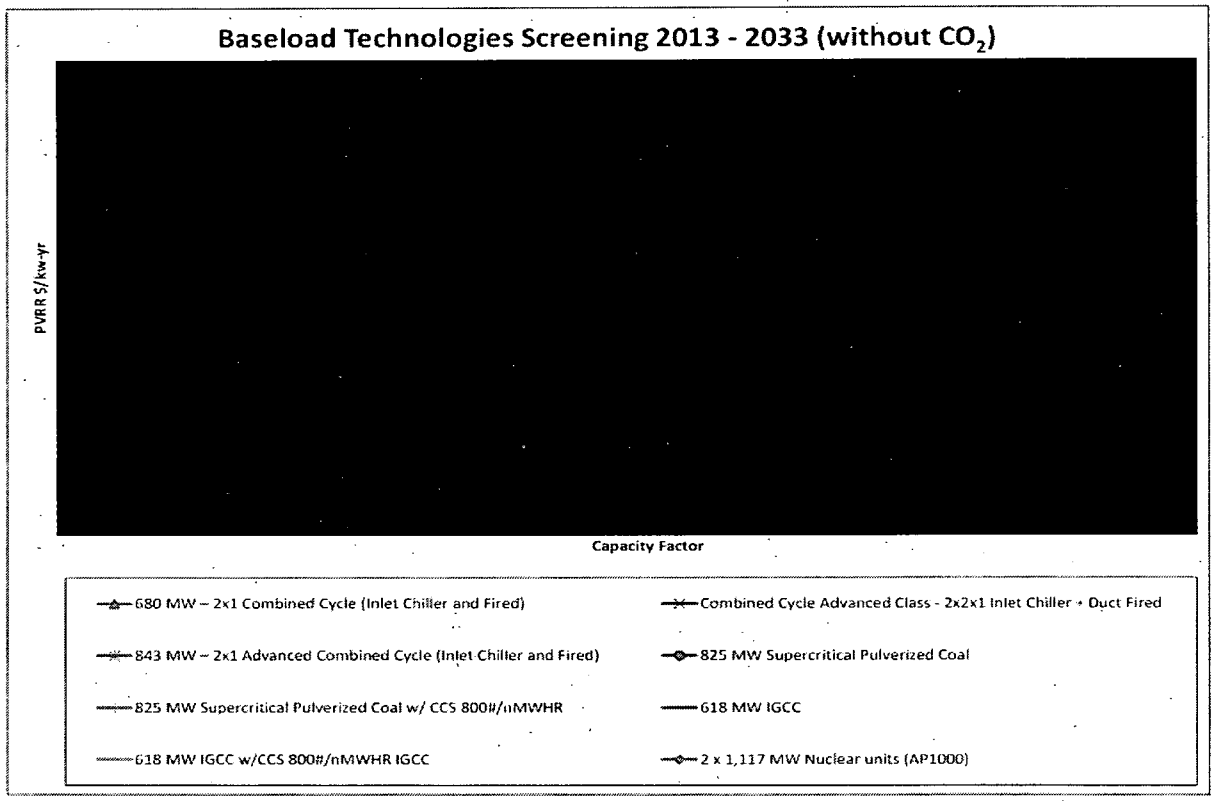

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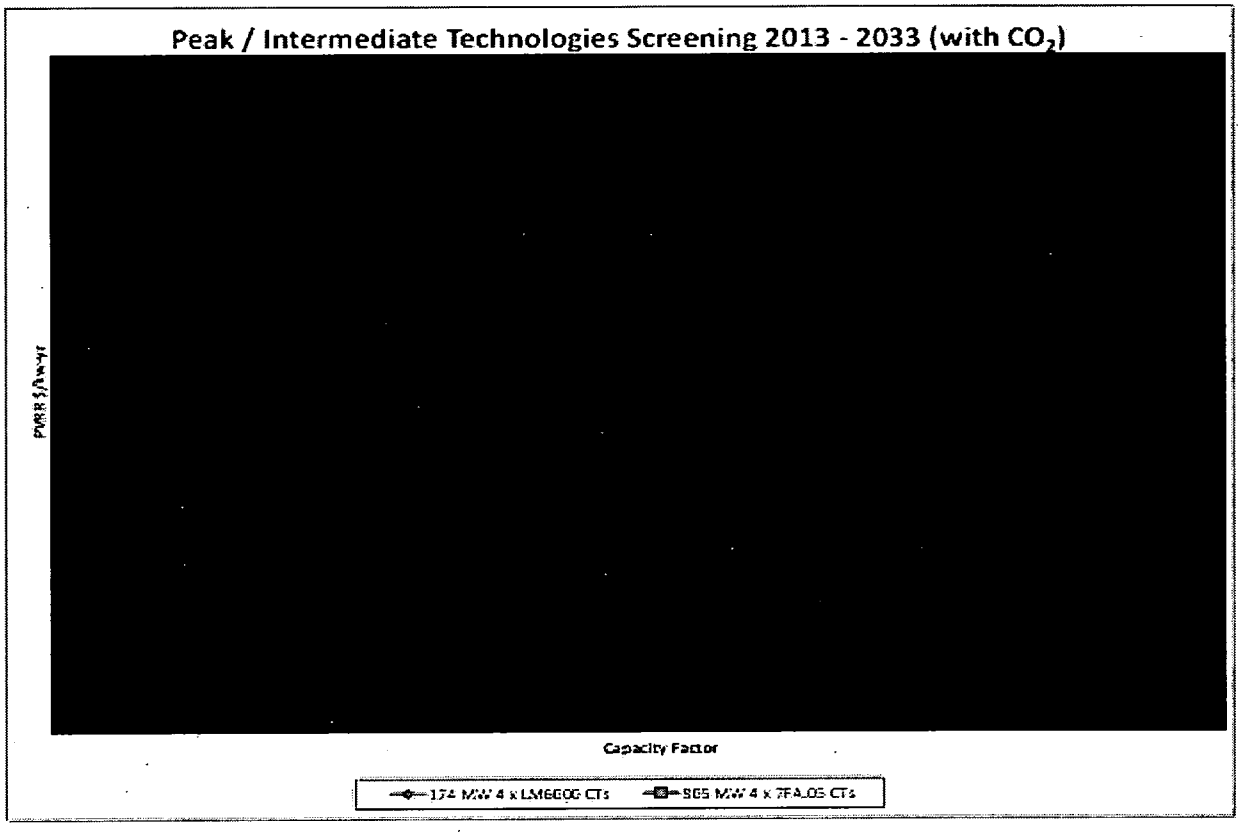

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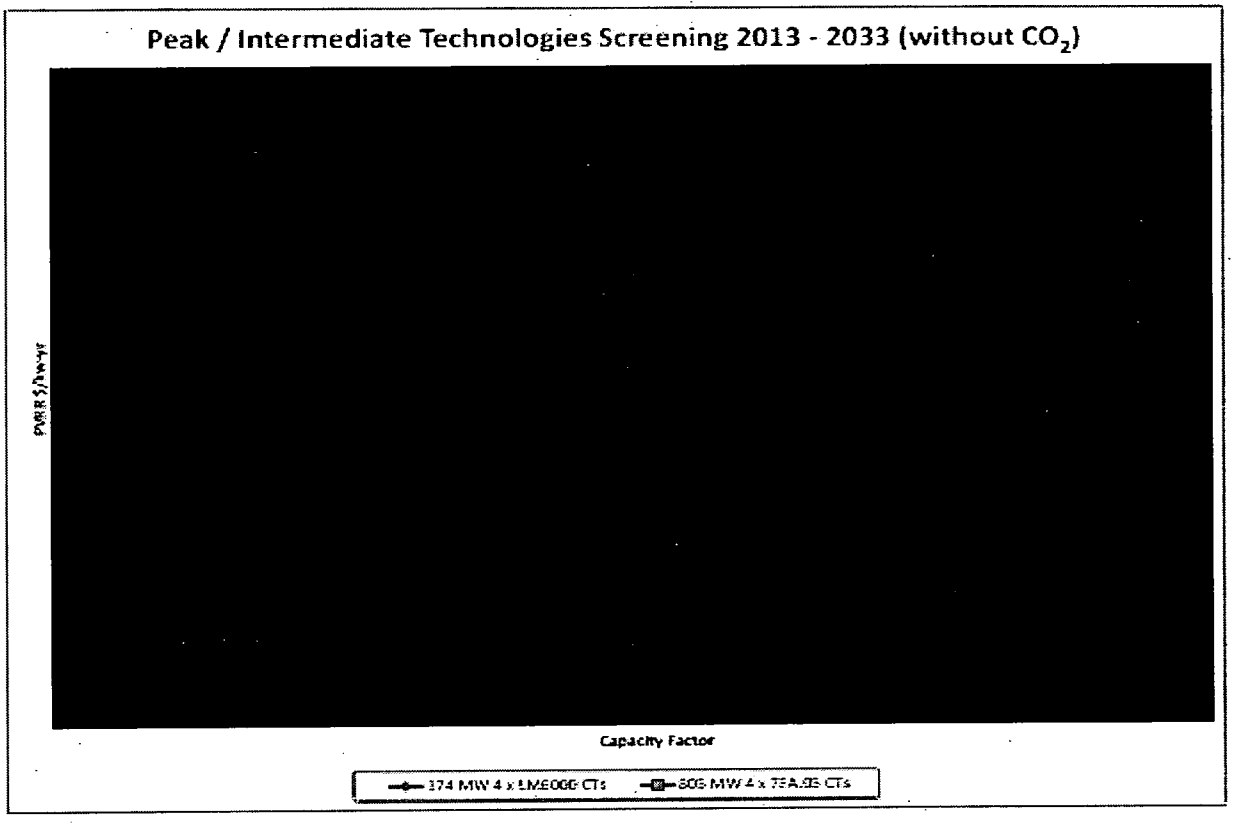

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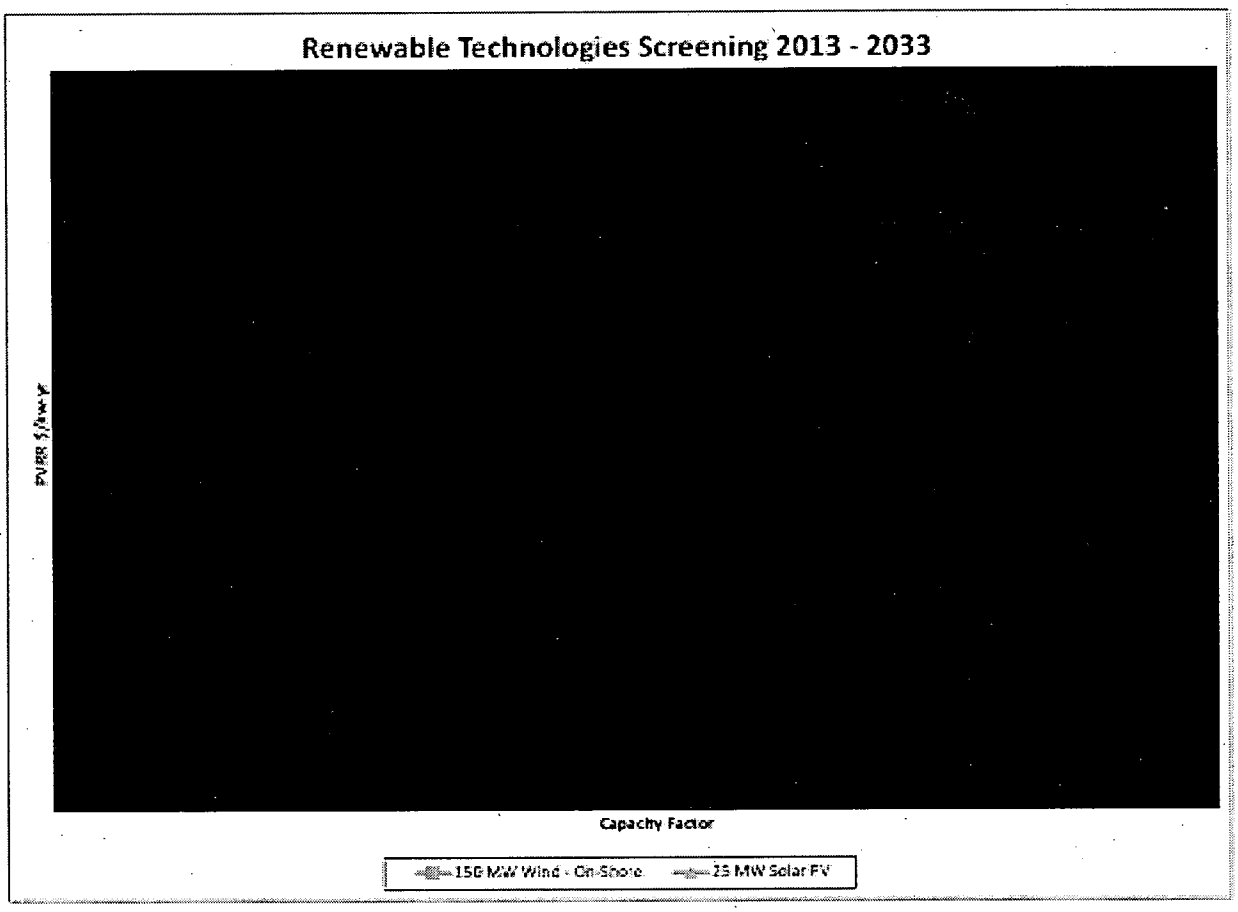


APPENDIX G: ENVIRONMENTAL COMPLIANCE

Legislative and Regulatory Issues

Duke Energy Carolinas, which is subject to the jurisdiction of federal agencies including the 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 Company's existing generation portfolio and choices for new generation resources.

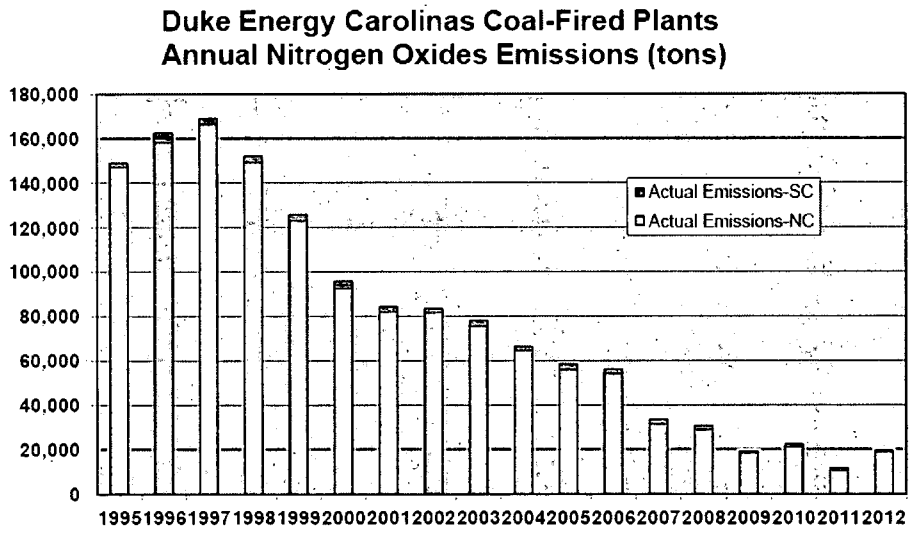
Air Quality

Duke Energy Carolinas is required to comply with numerous state and federal air emission regulations, including 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% by 2013 from 2000 levels. The law also required additional reductions in NO_X emissions in 2007 and 2009, beyond those required by CAIR, 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.

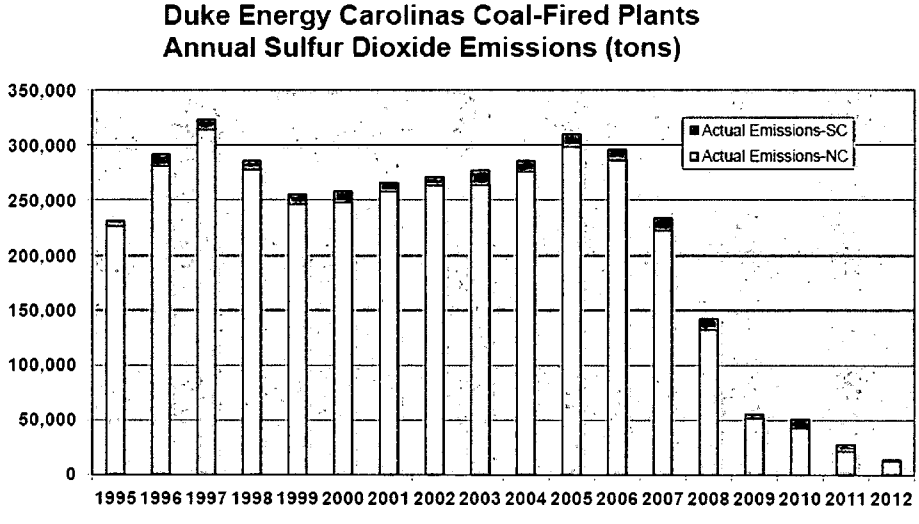
The charts below show the significant downward trend in both NO_x and SO_2 emissions through 2012 as a result of actions taken at DEC facilities.

Chart G-1 DEC NO_x Emssions



Overall reduction of 89% from 1997 to 2012 attributed to controls to meet Federal Requirements and NC Clean Air Legislation.

Chart G-2 DEC SO_2 Emissions



95 % Reduction from 2000 to 2012 attributed to scrubbers installed to meet NC Clean Air Legislation.

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 and the Clean Air Interstate Rule

The EPA finalized 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. In December 2008, the United States District Court for the District of Columbia issued a decision remanding CAIR to the EPA, allowing CAIR to remain in effect until EPA develops a replacement regulation.

In August 2011, a replacement for CAIR was finalized CSAPR, however, on December 30, 2011 the CSAPR was stayed by the U.S. Court of Appeals for the D.C. Circuit. Numerous petitions for review of the CSAPR were filed with the D.C. Circuit Court. On August 21, 2012, by a 2-1 decision, the D.C. Circuit vacated the CSAPR. The Court also directed the EPA to continue administering the CAIR that Duke Energy Carolinas has been complying with since 2009 pending completion of a remand rulemaking to replace CSAPR with a valid rule. CAIR requires additional Phase II reductions in SO_2 and NO_X emissions beginning in 2015. The court's decision to vacate the CSAPR leaves the future of the rule uncertain. The EPA filed a petition with the D.C. Circuit for en banc rehearing of the CSAPR decision, which the court denied. EPA then filed a petition with the Supreme Court asking that it review the D.C. Circuit's decision. On June 24, 2013 the Supreme Court granted review of the D.C. Circuit's August 21, 2012 decision. The Court will review the three issues presented in EPA's petition. Barring unforeseen developments, the Court could issue its decision by June 2014. The Supreme Court's order granting review does not change the legal status of CSAPR: CSAPR does not have legal effect at this time, and EPA is required to continue to administer the CAIR.

Duke Energy Carolinas cannot predict the outcome of the review process or how it could affect future emission reduction requirements that might apply as a result of a potential CSAPR replacement rulemaking. If the Supreme Court affirms the D.C. Circuit's decision on all issues, it is likely to take beyond 2015 for a replacement rulemaking to become effective which means that Phase II of CAIR would take effect on January 1, 2015. No risk for compliance with CAIR Phase I or Phase II exists, as such, no additional controls are planned. If the review process results in the CSAPR being g reinstated, it is unclear when EPA might move to implement the rule. Regardless of the timing, however, there is no risk for compliance with CSAPR Phase I or Phase II, as such; no additional controls would be required.

Mercury and Air Toxics Standard (MATS)

In February 2008, the United States Court of Appeals for the District of Columbia issued its opinion, vacating the Clean Air Mercury Rule (CAMR). EPA announced a proposed Utility Boiler Maximum Achievable Control Technology (MACT) rule in March 2011 to replace the CAMR. The EPA published the final rule, known as the MATS, in the Federal Register on February 16, 2012. MATS regulates Hazardous Air Pollutants (HAP) and establishes unit-level emission limits for mercury, acid gases, and non-mercury metals, and sets work practice standards for organics for coal and oil-fired electric generating units. Compliance with the emission limits will be required by April 16, 2015. Permitting authorities have the discretion to grant up to a 1-year compliance extension, on a case-by-case basis, to sources that are unable to install emission controls before the compliance deadline.

Numerous petitions for review of the final MATS rule have been filed with the United States Court of Appeals for the District of Columbia. Briefing in the case has been completed. Oral arguments have not been scheduled. A court decision in the case is not likely until the first quarter of 2014. Duke Energy Carolinas cannot predict the outcome of the litigation or how it might affect the MATS requirements as they apply to operations.

Based on the emission limits established by the MATS rule, compliance with the MATS rule has driven several unit retirements and will drive the retirement or fuel conversion of several more non-scrubbed coal-fired generating units in the Carolinas by April 2015. Compliance with MATS will also require various changes to units that have had emission controls added over the last several years to meet the emission requirements of the NC CSA.

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 of 2009, EPA announced a decision to reconsider the 75 ppb standard in response to a court challenge from environmental groups and their own belief that a lower standard was justified. However, EPA announced in September 2011 that it would retain the 75 ppb primary standard until it is reconsidered under the next 5-year review cycle. It could be mid-2014 before the EPA proposes a revision to the 75 ppb standard and mid-2015 before it finalizes a new standard unless ongoing legal action results in a court ordered schedule requiring the Agency to act sooner.

On May 21, 2012 EPA finalized the area designations for the 2008 75 ppb 8-hour ozone standard. The Charlotte area, the only area in North Carolina designated nonattainment, is now classified as a "marginal" nonattainment area, which establishes December 31, 2015 as its attainment date. For

marginal nonattainment areas, states are not required to prepare an attainment demonstration. EPA in its final rule states that it performed an analysis that indicates that the majority of areas classified as marginal will be able to attain the 75 ppb standard in 2015 due to federal and state emission reduction programs already in place. If the Charlotte area's air quality does not qualify it to be reclassified as attainment, the area can still qualify for the first of two possible one-year extensions of the attainment date if it has no more than one exceedance of the standard in 2015. Alternatively, should the Charlotte area not attain the standard by its attainment date and not qualify for an extension, it could be bumped up to the next higher classification, which for Charlotte would be moderate. This would require North Carolina to develop an attainment SIP to bring the Charlotte area into attainment with the standard by December 31, 2018.

SO_2 Standards

On June 22, 2010 EPA established a 75 ppb 1-hour SO_2 NAAQS and revoked the annual and 24-hour SO_2 standards. EPA finalized initial nonattainment area designations in TBD 2013. No areas in the Carolinas were designated nonattainment.

On February 6, 2013 the EPA released a document that updated its strategy for addressing all areas that it did not initially designate as nonattainment in July 2013. The document indicated that EPA will allow states to use modeling or monitoring to evaluate the impact of large SO_2 emitting sources relative to the 75 ppb standard. The document also laid out a schedule for implementing the standard.

The EPA plans on undertaking notice and comment rulemaking to codify the implementation requirements for the 75 ppb standard. There is no schedule for EPA to propose or finalize the rulemaking, and the outcome of the rulemaking could be different from what EPA put forth in its February 6, 2013 document.

Particulate Matter (PM) Standard

In September 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. In February 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 began undertaking new rulemaking to revise the standards consistent with the Court's decision.

On December 14, 2012 the EPA finalized a rule that lowered the annual $PM_{2.5}$ standard to 12 ug/m^3 and retained the 35 ug/m^3 daily $PM_{2.5}$ standard. The EPA plans to finalize area designations by December 2014. States with nonattainment areas will be required to submit State Implementation Plans (SIPs) to EPA in early 2018, with the initial attainment date in 2020. The EPA has indicated that it will likely use 2011 – 2013 air quality data to make final designations.

To date neither the annual nor the daily $PM_{2.5}$ standard has directly driven emission reduction requirements at Duke Energy Carolinas facilities. The reduction in SO_2 and NO_X emissions to address the $PM_{2.5}$ standards has been achieved through the CAIR and the NC CSA. It is unclear if the new lower annual $PM_{2.5}$ standard will require additional SO_2 or NO_X emission reduction requirements at any Duke Energy Carolinas generating facilities.

Greenhouse Gas Regulation

The EPA has been active in the regulation of GHGs. In May 2010, the EPA finalized what is commonly referred to as the Tailoring Rule. This rule sets the emission thresholds to 75,000 tons/year of CO_2 for determining when a modified major stationary source is subject to Prevention of Significant Deterioration (PSD) permitting for greenhouse gases. 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, the potential implications of this regulatory requirement are unknown.

On April 13, 2012, a proposed rule to establish GHG NSPS for new electric utility steam generating units (EGUs) was published in the Federal Register. The proposed GHG NSPS applies only to new pulverized coal, IGCC and natural gas combined cycle units. The proposed NSPS is an output-based emission standard of 1,000 lb CO_2/gross MWh of electricity generation. The proposal was very controversial because it set the same emission standard for new natural gas and new coal-fired electric generating units. The only way a new coal unit could meet the proposed standard is with carbon capture and storage technology. The President has directed EPA to re-propose the rule by September 20, 2013. The requirements of a re-proposed rule are not known.

The President has directed EPA to propose CO_2 emission guidelines for existing electric generating units by June 1, 2014, and finalize guidelines by June 1, 2015. Once EPA finalizes emission guidelines for existing sources, the states will be required to develop the regulations that will apply to covered sources, based on the emission performance standards established by EPA in its guidelines.

It is highly unlikely that legislation mandating reductions in GHG emissions or establishing a carbon tax will be passed by the 113th Congress which began on January 3, 2013. Beyond 2014 the prospects for enactment of any federal legislation mandating reductions in GHG emissions or establishing a carbon tax are highly uncertain.

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 for existing facilities to minimize impingement and entrainment of aquatic organisms. EPA published its proposed rule on April 20, 2011.

The proposed rule establishes mortality reduction requirements due to both fish impingement and entrainment and advances one preferred approach and three alternatives. The EPA's preferred approach establishes aquatic protection requirements and new on-site facility additions for existing facilities with a design intake flow of 2 million gallons per day (mgd) or more from rivers, streams, lakes, reservoirs, estuaries, oceans, or other U.S. waters that utilize at least 25% of the water withdrawn for cooling purposes.

The most recent EPA settlement agreement now calls for the EPA to finalize the 316(b) rule by November 4, 2013. If the rule is finalized as proposed, initial submittals, station details, study plans, etc, for some facilities would be due in mid-late 2014. If required, modifications to the intakes to comply with the impingement requirements could be required as early as late 2016. Within the proposed rule, EPA did not provide a compliance deadline for meeting the entrainment requirements.

Steam Electric Effluent Guidelines

In September 2009, EPA announced plans to revise the steam electric effluent limitation guidelines. The steam electric effluent limitation guidelines are technology-based, in that limits are based on the capability of the best technology available. On April 19, 2013, the EPA Acting Administrator signed the proposed revisions to the Steam Electric Effluent Limitations Guidelines (ELGs). The proposal was published in the Federal Register on June 7, 2013 with comments due to EPA by the extended date of September 20, 2013. Under the current revision of the consent decree, the EPA has agreed to issue a final rule by May 22, 2014. The EPA has proposed eight different regulatory options for the rule, of which four are listed as preferred by EPA. The eight regulatory options vary in stringency and cost, and propose revisions or develop new standards for seven waste streams, including wastewater from air pollution control equipment and ash transport water. The proposed revisions are focused primarily on coal generating units, but some revisions would be

applicable to all steam electric generating units, including natural gas and nuclear-fueled generating facilities. After the final rulemaking, effluent limitation guideline requirements will be included in a station's National Pollutant Discharge Elimination System (NPDES) permit renewals. Portions of the rule would be implemented immediately after the effective date of the rule upon the renewal of wastewater discharge permits, while other portions of the rule will be implemented upon the renewal of the wastewater discharge permits after July, 2017. EPA expects that all facilities will be in compliance with the rule by July 2022. The deadline to comply will depend upon each station's permit renewal schedule.

Coal Combustion Residuals

Following Tennessee Valley Authority's (TVA) Kingston ash dike failure in December 2008, EPA began to assess the integrity of ash dikes nationwide and to begin developing a rule to manage coal combustion residuals (CCRs). CCRs primarily include fly ash, bottom ash and Flue Gas Desulfurization (FGD) byproducts (gypsum). Since the 2008 TVA 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 published its proposed rule regarding CCRs. The proposed rule offers two options: 1) a hazardous waste classification under Resource Conservation 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 will likely result in more conversions to dry handling of ash, more landfills, the closing or lining of existing ash ponds and the addition of new wastewater treatment systems. Final regulations are not expected to be issued by EPA until 2014 or later. EPA's regulatory classification of CCRs as hazardous or non-hazardous will be critical in developing plans for handling CCRs. However, under either option of the proposed rule, the impact to Duke Energy Carolinas is likely to be significant. Based on a 2014 final rule date, compliance with new regulations is generally expected to begin around 2019.

APPENDIX H: NON-UTILITY GENERATION AND WHOLESALE

This appendix contains wholesale sales contracts, firm wholesale purchased power contracts and non-utility generation contracts.

Table H-1 Wholesale Sales Contracts

			Wholesale Contracts									
			Commitment (MW)									
Customer	**Product**	**Term**	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Concord	Partial Requirements	2009-2018	167	169	172	174	177	180	212	215	217	220
Dallas	Partial Requirements	2009-2028	11	11	11	12	12	12	12	12	13	13
Due West	Partial Requirements	2009-2018	2	2	2	2	2	2	2	2	2	2
Forest City	Partial Requirements	2009-2028	18	18	19	19	19	20	20	20	21	21
Greenwood	Full Requirements	2010-2018	53	53	54	55	56	57	58	58	59	60
Highlands	Full Requirements	2010-2029	9	9	9	9	9	9	9	9	10	10
Kings Mountain	Partial Requirements	2009-2018	21	21	21	22	22	22	30	30	30	31
Lockhart	Partial Requirements	2009-2018	50	50	51	52	53	54	75	76	77	78
Prosperity	Partial Requirements	2009-2028	2	2	2	2	2	2	3	3	3	3
Western Carolina	Full Requirements	2010-2021	6	6	6	6	6	6	6	6	6	6
Blue Ridge EMC	Full Requirements	2010-2031	225	229	233	237	241	245	249	253	257	261
Central	Partial Requirements	2013-2030	120	244	374	509	649	793	900	918	936	953
Haywood EMC	Full Requirements	2009-2021	23	23	23	24	24	24	25	25	25	26
NCEMC	Fixed Load Shape	2009-2038	72	72	72	72	72	72	72	72	72	72
NCEMC	Backstand	1985-2043	95	116	116	116	116	116	116	116	116	116
Piedmont EMC	Full Requirements	2010-2031	87	88	89	90	92	93	94	96	97	99
PMPA	Backstand	2014-2020	0	47	47	47	47	47	47	47	47	47
Rutherford EMC	Partial Requirements	2010-2031	185	189	204	208	212	217	221	226	230	235

Table H-2 ***Firm Wholesale Purchased Power Contracts***

Purchased Power Contract	Primary Fuel Type	Summer Capacity (MW)	Capacity Designation	Location	Term	Volume of Purchases (MWh) Jul 12-Jun 13
Cherokee County Cogeneration Partners, LLC 1	Gas	86	Peaking	Gaffney, SC	12/31/2020	650,627
SEPA	Hydro	8	Peaking	GA-AL-SC system	12/31/2021	12,883

Note: The capacities shown are delivered to the DEC system and may differ from the contracted amount. Renewables purchases are listed in the NC REPS Compliance Plan in the Attachment to this IRP.

Table H-3 Non-Utility Generation – North Carolina

NORTH CAROLINA GENERATORS (As of July 2013)

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC kW)	Designation
Facility 1	Henderson	NC	Solar	8.64	Intermediate/Peak
Facility 2	Henderson	NC	Solar	10.25	Intermediate/Peak
Facility 3	Lincoln	NC	Solar	75.00	Intermediate/Peak
Facility 4	Gaston	NC	Hydroelectric	640.00	Baseload
Facility 5	Orange	NC	Solar	7.10	Intermediate/Peak
Facility 6	Orange	NC	Solar	2.80	Intermediate/Peak
Facility 7	Alamance	NC	Solar	5.00	Intermediate/Peak
Facility 8	Alamance	NC	Hydroelectric	240.00	Baseload
Facility 9	Cleveland	NC	Solar	1.72	Intermediate/Peak
Facility 10	Henderson	NC	Solar	95.00	Intermediate/Peak
Facility 11	Charlotte	NC	Other*	1750.00	Intermediate/Peak
Facility 12	Orange	NC	Solar	4.00	Intermediate/Peak
Facility 13	Mount Holly	NC	Other*	NA	Intermediate/Peak
Facility 14	Henderson	NC	Solar	2.10	Intermediate/Peak
Facility 15	Mecklenburg	NC	Solar	5.00	Intermediate/Peak
Facility 16	Cherokee	NC	Solar	9.60	Intermediate/Peak
Facility 17	Gaston	NC	Solar	2.58	Intermediate/Peak
Facility 18	Mecklenburg	NC	Solar	5.25	Intermediate/Peak
Facility 19	Forsyth	NC	Solar	4.00	Intermediate/Peak
Facility 20	Polk	NC	Solar	6.00	Intermediate/Peak
Facility 21	Catawba	NC	Solar	20000.00	Intermediate/Peak
Facility 22	Catawba	NC	Biogas	4800.00	Baseload
Facility 23	Iredell	NC	Solar	10.00	Intermediate/Peak
Facility 24	Iredell	NC	Solar	10.00	Intermediate/Peak
Facility 25	Surry	NC	Solar	3500.00	Intermediate/Peak
Facility 26	Orange	NC	Solar	3.60	Intermediate/Peak
Facility 27	Catawba	NC	Solar	5000.00	Intermediate/Peak
Facility 28	Orange	NC	Solar	9.46	Intermediate/Peak
Facility 29	Macon	NC	Wind	4.00	Intermediate/Peak
Facility 30	Orange	NC	Solar	10.00	Intermediate/Peak
Facility 31	Durham	NC	Other*	1600.00	Intermediate/Peak
Facility 32	Burlington	NC	Solar	4.52	Intermediate/Peak
Facility 33	Rutherford	NC	Hydroelectric	324.00	Baseload
Facility 34	Mecklenburg	NC	Solar	1.90	Intermediate/Peak
Facility 35	Cleveland	NC	Solar	10.00	Intermediate/Peak
Facility 36	Swain	NC	Solar	3.00	Intermediate/Peak
Facility 37	Guilford	NC	Solar	28.80	Intermediate/Peak
Facility 38	Charlotte	NC	Other*	NA	Intermediate/Peak
Facility 39	Alamance	NC	Solar	30.00	Intermediate/Peak
Facility 40	Mecklenburg	NC	Solar	30.00	Intermediate/Peak
Facility 41	Cleveland	NC	Solar	4000.00	Intermediate/Peak
Facility 42		NC	Solar	3.25	Intermediate/Peak
Facility 43	Catawba	NC	Solar	4.00	Intermediate/Peak
Facility 44	Guilford	NC	Solar	3.85	Intermediate/Peak
Facility 45	Durham- NE	NC	Solar	2.21	Intermediate/Peak
Facility 46	Rockingham	NC	Solar	5.16	Intermediate/Peak
Facility 47	Durham	NC	Solar	124.00	Intermediate/Peak
Facility 48	Henderson	NC	Solar	9.00	Intermediate/Peak
Facility 49	Alamance	NC	Solar	40.85	Intermediate/Peak
Facility 50	Alamance	NC	Solar	20.43	Intermediate/Peak
Facility 51	Alamance	NC	Solar	0.74	Intermediate/Peak
Facility 52	Henderson	NC	Solar	9.80	Intermediate/Peak
Facility 53	Orange	NC	Solar	3.00	Intermediate/Peak
Facility 54	Cabarrus	NC	Solar	6.08	Intermediate/Peak
Facility 55	Mecklenburg	NC	Solar	2.45	Intermediate/Peak
Facility 56	Guilford	NC	Solar	4.00	Intermediate/Peak

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC kW)	Designation
Facility 57	Durham	NC	Solar	3.78	Intermediate/Peak
Facility 58	Orange	NC	Solar	7.00	Intermediate/Peak
Facility 59	Alamance	NC	Hydroelectric	440.00	Baseload
Facility 60	Orange	NC	Solar	3.00	Intermediate/Peak
Facility 61	Jackson	NC	Solar	5.00	Intermediate/Peak
Facility 62	Durham	NC	Solar	6.45	Intermediate/Peak
Facility 63	Surry	NC	Solar	6.00	Intermediate/Peak
Facility 64	Charlotte	NC	Other*	1250.00	Intermediate/Peak
Facility 65	Orange	NC	Solar	2.00	Intermediate/Peak
Facility 66	Orange	NC	Solar	5.00	Intermediate/Peak
Facility 67	Catawba	NC	Landfill Gas	4000.00	Baseload
Facility 68	Iredell	NC	Solar	3.00	Intermediate/Peak
Facility 69	Elkin	NC	Other*	400.00	Intermediate/Peak
Facility 70	Alamance	NC	Solar	3.00	Intermediate/Peak
Facility 71	Orange	NC	Solar	4.00	Intermediate/Peak
Facility 72	Orange	NC	Solar	16.40	Intermediate/Peak
Facility 73	Durham	NC	Solar	4.16	Intermediate/Peak
Facility 74	Henderson	NC	Solar	4.88	Intermediate/Peak
Facility 75	Forsyth	NC	Solar	0.74	Intermediate/Peak
Facility 76	Mecklenburg	NC	Solar	1.85	Intermediate/Peak
Facility 77	Alamance	NC	Solar	3.00	Intermediate/Peak
Facility 78	Orange	NC	Solar	2.40	Intermediate/Peak
Facility 79	Cleveland	NC	Solar	15.00	Intermediate/Peak
Facility 80	Swain	NC	Solar	3.00	Intermediate/Peak
Facility 81	Stokes	NC	Solar	4.94	Intermediate/Peak
Facility 82	Gaston	NC	Solar	7.50	Intermediate/Peak
Facility 83		NC	Solar	N/A	Intermediate/Peak
Facility 84	Orange	NC	Solar	8.00	Intermediate/Peak
Facility 85	Union	NC	Solar	2.63	Intermediate/Peak
Facility 86	Union	NC	Solar	3.00	Intermediate/Peak
Facility 87	Mecklenburg	NC	Solar	6.00	Intermediate/Peak
Facility 88	RTP	NC	Other*	1300.00	Intermediate/Peak
Facility 89	Durham	NC	Solar	100.00	Intermediate/Peak
Facility 90	Belmont	NC	Other*	350.00	Intermediate/Peak
Facility 91	Belmont	NC	Other*	500.00	Intermediate/Peak
Facility 92	Belmont	NC	Other*	350.00	Intermediate/Peak
Facility 93	Bessemer City	NC	Other*	440.00	Intermediate/Peak
Facility 94	Haw River	NC	Other*	550.00	Intermediate/Peak
Facility 95	Burlington	NC	Other*	600.00	Intermediate/Peak
Facility 96	Mecklenburg	NC	Solar	260.82	Intermediate/Peak
Facility 97	Charlotte	NC	Other*	2250.00	Intermediate/Peak
Facility 98	Charlotte	NC	Other*	1200.00	Intermediate/Peak
Facility 99	Mecklenburg	NC	Solar	100.00	Intermediate/Peak
Facility 100	Mecklenburg	NC	Solar	8.00	Intermediate/Peak
Facility 101	Eden	NC	Other*	1700.00	Intermediate/Peak
Facility 102	Gastonia	NC	Other*	1590.00	Intermediate/Peak
Facility 103	Mebane	NC	Other*	800.00	Intermediate/Peak
Facility 104	Graham	NC	Other*	800.00	Intermediate/Peak
Facility 105	Greensboro	NC	Other*	2000.00	Intermediate/Peak
Facility 106	Greensboro	NC	Other*	859.00	Intermediate/Peak
Facility 107	Hickory	NC	Other*	1500.00	Intermediate/Peak
Facility 108	Hickory	NC	Other*	1750.00	Intermediate/Peak
Facility 109	Tobaccoville	NC	Other*	800.00	Intermediate/Peak
Facility 110	Mount Airy	NC	Other*	600.00	Intermediate/Peak
Facility 111	Mount Airy	NC	Other*	750.00	Intermediate/Peak
Facility 112	Mount Holly	NC	Other*	210.00	Intermediate/Peak

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC kW)	Designation
Facility 113	Guilford	NC	Solar	4.00	Intermediate/Peak
Facility 114	Cleveland	NC	Solar	0.86	Intermediate/Peak
Facility 115	Durham	NC	Solar	30.00	Intermediate/Peak
Facility 116	Durham	NC	Wind	3.00	Intermediate/Peak
Facility 117	Rutherford	NC	Hydroelectric	1600.00	Baseload
Facility 118	Surry	NC	Landfill Gas	1600.00	Baseload
Facility 119	Charlotte	NC	Other*	420.00	Intermediate/Peak
Facility 120	Rockingham	NC	Solar	169.00	Intermediate/Peak
Facility 121	Davie	NC	Solar	10.00	Intermediate/Peak
Facility 122	Cabarrus	NC	Landfill Gas	11500.00	Baseload
Facility 123	Henderson	NC	Solar	10.00	Intermediate/Peak
Facility 124	Orange	NC	Solar	9.90	Intermediate/Peak
Facility 125	Orange	NC	Solar	3.01	Intermediate/Peak
Facility 126	Forsyth	NC	Solar	2.82	Intermediate/Peak
Facility 127	Rowan	NC	Solar	5.76	Intermediate/Peak
Facility 128	Orange	NC	Solar	4.00	Intermediate/Peak
Facility 129	Wake	NC	Solar	7.60	Intermediate/Peak
Facility 130	Wake	NC	Solar	6.08	Intermediate/Peak
Facility 131	Forsyth	NC	Solar	1.72	Intermediate/Peak
Facility 132	Durham	NC	Solar	3.44	Intermediate/Peak
Facility 133	Durham	NC	Solar	2.28	Intermediate/Peak
Facility 134	Catawba	NC	Solar	2.58	Intermediate/Peak
Facility 135	Henderson	NC	Solar	4.94	Intermediate/Peak
Facility 136	Gaston	NC	Solar	3.00	Intermediate/Peak
Facility 137	Orange	NC	Solar	3.60	Intermediate/Peak
Facility 138	Stokes	NC	Solar	1.44	Intermediate/Peak
Facility 139	Durham	NC	Solar	4.00	Intermediate/Peak
Facility 140	Iredell	NC	Solar	4.58	Intermediate/Peak
Facility 141	Transylvania	NC	Solar	5.16	Intermediate/Peak
Facility 142	Henderson	NC	Wind	1.20	Intermediate/Peak
Facility 143	Guilford	NC	Solar	6.02	Intermediate/Peak
Facility 144	Rowan	NC	Solar	4.30	Intermediate/Peak
Facility 145	Stokes	NC	Solar	3.60	Intermediate/Peak
Facility 146	Mecklenburg	NC	Solar	1.12	Intermediate/Peak
Facility 147	Cleveland	NC	Solar	5.16	Intermediate/Peak
Facility 148	Forsyth	NC	Solar	2.58	Intermediate/Peak
Facility 149	Caldwell	NC	Solar	6.00	Intermediate/Peak
Facility 150	Cleveland	NC	Solar	2.28	Intermediate/Peak
Facility 151	Orange	NC	Solar	7.60	Intermediate/Peak
Facility 152	Mecklenburg	NC	Solar	0.70	Intermediate/Peak
Facility 153	Rowan	NC	Solar	6.00	Intermediate/Peak
Facility 154	Rowan	NC	Wind	1.00	Intermediate/Peak
Facility 155	Jackson	NC	Solar	5.46	Intermediate/Peak
Facility 156	Union	NC	Solar	3.50	Intermediate/Peak
Facility 157	Henderson	NC	Solar	3.00	Intermediate/Peak
Facility 158	Orange	NC	Solar	2.50	Intermediate/Peak
Facility 159	Mecklenburg	NC	Solar	94.08	Intermediate/Peak
Facility 160	Davidson	NC	Landfill Gas	1600.00	Baseload
Facility 161	Lexington	NC	Other*	300.00	Intermediate/Peak
Facility 162	Lexington	NC	Other*	750.00	Intermediate/Peak
Facility 163	Forsyth	NC	Solar	0.70	Intermediate/Peak
Facility 164	Guilford	NC	Solar	72.00	Intermediate/Peak
Facility 165	Durham	NC	Solar	2.50	Intermediate/Peak
Facility 166	Mecklenburg	NC	Solar	30.00	Intermediate/Peak
Facility 167	Rowan	NC	Solar	4.00	Intermediate/Peak
Facility 168	Durham	NC	Solar	30.00	Intermediate/Peak

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC kW)	Designation
Facility 169	Jackson	NC	Solar	3.60	Intermediate/Peak
Facility 170	Guilford	NC	Solar	6.72	Intermediate/Peak
Facility 171	Cabarrus	NC	Solar	3.44	Intermediate/Peak
Facility 172	Jackson	NC	Solar	4.41	Intermediate/Peak
Facility 173	Wilkes	NC	Solar	2.76	Intermediate/Peak
Facility 174	Forsyth	NC	Solar	2.23	Intermediate/Peak
Facility 175	Mecklenburg	NC	Solar	2.15	Intermediate/Peak
Facility 176	Rockingham	NC	Solar	5000.00	Intermediate/Peak
Facility 177	Orange	NC	Solar	3.87	Intermediate/Peak
Facility 178	Mecklenburg	NC	Solar	5.00	Intermediate/Peak
Facility 179	Cleveland	NC	Solar	4000.00	Intermediate/Peak
Facility 180		NC	Solar	4.30	Intermediate/Peak
Facility 181	Mecklenburg	NC	Solar	4.00	Intermediate/Peak
Facility 182	Guilford	NC	Solar	2.58	Intermediate/Peak
Facility 183	Iredell	NC	Solar	6.02	Intermediate/Peak
Facility 184	Macon	NC	Solar	4.50	Intermediate/Peak
Facility 185	Alexander	NC	Solar	0.70	Intermediate/Peak
Facility 186	Orange	NC	Solar	3.00	Intermediate/Peak
Facility 187	Rockingham	NC	Solar	1.60	Intermediate/Peak
Facility 188	Burke	NC	Solar	3.00	Intermediate/Peak
Facility 189	Alamance	NC	Solar	3.00	Intermediate/Peak
Facility 190	Catawba	NC	Solar	2.50	Intermediate/Peak
Facility 191	Polk	NC	Solar	3.60	Intermediate/Peak
Facility 192	Rockingham	NC	Solar	3.87	Intermediate/Peak
Facility 193	Guilford	NC	Solar	3.00	Intermediate/Peak
Facility 194	Forsyth	NC	Solar	10.56	Intermediate/Peak
Facility 195	Durham	NC	Other*	5500.00	Intermediate/Peak
Facility 196	Durham	NC	Other*	13400.00	Intermediate/Peak
Facility 197	Durham	NC	Other*	2250.00	Intermediate/Peak
Facility 198	Orange	NC	Solar	10.68	Intermediate/Peak
Facility 199	Davidson	NC	Engine Dynamometer	N/A	Intermediate/Peak
Facility 200	Cherokee	NC	Solar	13.72	Intermediate/Peak
Facility 201		NC	Solar	5.16	Intermediate/Peak
Facility 202	Orange	NC	Solar	4.00	Intermediate/Peak
Facility 203	Macon	NC	Solar	8.60	Intermediate/Peak
Facility 204	Orange	NC	Solar	6.00	Intermediate/Peak
Facility 205	Mecklenburg	NC	Solar	3.00	Intermediate/Peak
Facility 206	Mecklenburg	NC	Solar	4.00	Intermediate/Peak
Facility 207	Orange	NC	Solar	3.00	Intermediate/Peak
Facility 208	Orange	NC	Solar	3.00	Intermediate/Peak
Facility 209	Durham	NC	Solar	4.00	Intermediate/Peak
Facility 210	Mecklenburg	NC	Solar	4.58	Intermediate/Peak
Facility 211	Alamance	NC	Solar	5.00	Intermediate/Peak
Facility 212	Guilford	NC	Solar	4.80	Intermediate/Peak
Facility 213	McDowell	NC	Solar	18.00	Intermediate/Peak
Facility 214	Caldwell	NC	Solar	1.40	Intermediate/Peak
Facility 215	Durham	NC	Solar	75.00	Intermediate/Peak
Facility 216	Durham	NC	Solar	52.90	Intermediate/Peak
Facility 217		NC	Solar	50.00	Intermediate/Peak
Facility 218	Durham	NC	Solar	30.00	Intermediate/Peak
Facility 219	Monroe	NC	Other*	400.00	Intermediate/Peak
Facility 220	Union	NC	Solar	4.00	Intermediate/Peak
Facility 221	Durham	NC	Solar	2.16	Intermediate/Peak
Facility 222	Guilford	NC	Solar	5.00	Intermediate/Peak
Facility 223	Durham	NC	Solar	5.00	Intermediate/Peak
Facility 224	Wake	NC	Solar	2.82	Intermediate/Peak

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC kW)	Designation
Facility 225	Henderson	NC	Solar	4.90	Intermediate/Peak
Facility 226	Mecklenburg	NC	Solar	2.85	Intermediate/Peak
Facility 227	Charlotte	NC	Other*	10000.00	Intermediate/Peak
Facility 228	Guilford	NC	Solar	14.40	Intermediate/Peak
Facility 229	Forsyth	NC	Solar	2.38	Intermediate/Peak
Facility 230	McDowell	NC	Solar	4.00	Intermediate/Peak
Facility 231	Alamance	NC	Solar	2.70	Intermediate/Peak
Facility 232	Charlotte	NC	Other*	300.00	Intermediate/Peak
Facility 233	Burke	NC	Solar	24.00	Intermediate/Peak
Facility 234	Winston-Salem	NC	Other*	1800.00	Intermediate/Peak
Facility 235	Forsyth	NC	Solar	2.30	Intermediate/Peak
Facility 236	Catawba	NC	Solar	4.50	Intermediate/Peak
Facility 237	Mecklenburg	NC	Solar	11.77	Intermediate/Peak
Facility 238	Orange	NC	Solar	5.00	Intermediate/Peak
Facility 239	Orange	NC	Solar	5.00	Intermediate/Peak
Facility 240	Rowan	NC	Solar	82.00	Intermediate/Peak
Facility 241	Mecklenburg	NC	Solar	8.00	Intermediate/Peak
Facility 242	Henderson	NC	Solar	5.00	Intermediate/Peak
Facility 243	Guilford	NC	Solar	1.75	Intermediate/Peak
Facility 244	Transylvania	NC	Solar	2.80	Intermediate/Peak
Facility 245	Polk	NC	Solar	3.00	Intermediate/Peak
Facility 246	Surry	NC	Solar	10.00	Intermediate/Peak
Facility 247	Jackson	NC	Solar	2.58	Intermediate/Peak
Facility 248	Cabarrus	NC	Landfill Gas	5000.00	Baseload
Facility 249	Gaston	NC	Landfill Gas	4800.00	Baseload
Facility 250	Guilford	NC	Solar	2.16	Intermediate/Peak
Facility 251	Durham	NC	Solar	700.00	Intermediate/Peak
Facility 252	Greensboro	NC	Other*	125.00	Intermediate/Peak
Facility 253	Guilford	NC	Solar	0.86	Intermediate/Peak
Facility 254	Orange	NC	Solar	6.00	Intermediate/Peak
Facility 255	Burke	NC	Solar	6.00	Intermediate/Peak
Facility 256	Henderson	NC	Solar	2.82	Intermediate/Peak
Facility 257	Cabarrus	NC	Solar	4.30	Intermediate/Peak
Facility 258	Polk	NC	Solar	2.14	Intermediate/Peak
Facility 259	Mecklenburg	NC	Solar	1.96	Intermediate/Peak
Facility 260	Wilkes	NC	Solar	2.58	Intermediate/Peak
Facility 261	Swain	NC	Solar	7.00	Intermediate/Peak
Facility 262	McDowell	NC	Solar	2.50	Intermediate/Peak
Facility 263	Guilford	NC	Solar	4.16	Intermediate/Peak
Facility 264	Orange	NC	Solar	1.64	Intermediate/Peak
Facility 265	Durham	NC	Solar	307.43	Intermediate/Peak
Facility 266	Catawba	NC	Solar	1.40	Intermediate/Peak
Facility 267	Mecklenburg	NC	Solar	1.72	Intermediate/Peak
Facility 268	Polk	NC	Solar	2.15	Intermediate/Peak
Facility 269	Guilford	NC	Solar	50.00	Intermediate/Peak
Facility 270	Macon	NC	Solar	4.30	Intermediate/Peak
Facility 271	Lincoln	NC	Solar	0.70	Intermediate/Peak
Facility 272	Cabarrus	NC	Solar	3.01	Intermediate/Peak
Facility 273	Forsyth	NC	Solar	8.00	Intermediate/Peak
Facility 274	Rutherford	NC	Solar	2.58	Intermediate/Peak
Facility 275	Orange	NC	Solar	4.20	Intermediate/Peak
Facility 276	Orange	NC	Solar	3.15	Intermediate/Peak
Facility 277	Alexander	NC	Hydroelectric	365.00	Baseload
Facility 278	Forsyth	NC	Solar	14.80	Intermediate/Peak
Facility 279	Gaston	NC	Hydroelectric	820.00	Baseload
Facility 280	Guilford	NC	Solar	7.50	Intermediate/Peak

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC kW)	Designation
Facility 281	Wilkes	NC	Solar	4.00	Intermediate/Peak
Facility 282	Cabarrus	NC	Solar	5.20	Intermediate/Peak
Facility 283	Alamance	NC	Hydroelectric	1500.00	Baseload
Facility 284	Alamance	NC	Solar	2.00	Intermediate/Peak
Facility 285	Durham	NC	Solar	3.01	Intermediate/Peak
Facility 286	Orange	NC	Solar	3.30	Intermediate/Peak
Facility 287	Orange	NC	Solar	7.00	Intermediate/Peak
Facility 288	Mecklenburg	NC	Engine Dynamometer	N/A	Intermediate/Peak
Facility 289	Guilford	NC	Solar	108.00	Intermediate/Peak
Facility 290	Mecklenburg	NC	Solar	2.15	Intermediate/Peak
Facility 291	Davidson	NC	Solar	1.29	Intermediate/Peak
Facility 292	Durham	NC	Solar	3.00	Intermediate/Peak
Facility 293	Alamance	NC	Solar	4.00	Intermediate/Peak
Facility 294	Lincoln	NC	Solar	2.15	Intermediate/Peak
Facility 295	Orange	NC	Solar	3.00	Intermediate/Peak
Facility 296	Research Triangle Park	NC	Other*	10900.00	Intermediate/Peak
Facility 297	Mecklenburg	NC	Solar	790.00	Intermediate/Peak
Facility 298	Mecklenburg	NC	Solar	3.60	Intermediate/Peak
Facility 299	Hickory	NC	Other*	1040.00	Intermediate/Peak
Facility 300	Rockingham	NC	Hydroelectric	500.00	Baseload
Facility 301	Lincoln	NC	Solar	10.00	Intermediate/Peak
Facility 302	Henderson	NC	Solar	6.00	Intermediate/Peak
Facility 303	Henderson	NC	Solar	6.00	Intermediate/Peak
Facility 304	Orange	NC	Solar	9.17	Intermediate/Peak
Facility 305	Orange	NC	Solar	5.00	Intermediate/Peak
Facility 306	Mecklenburg	NC	Solar	5.00	Intermediate/Peak
Facility 307	Polk	NC	Solar	5.16	Intermediate/Peak
Facility 308	Surry	NC	Solar	12.26	Intermediate/Peak
Facility 309	Mecklenburg	NC	Solar	4.00	Intermediate/Peak
Facility 310	Durham	NC	Solar	3.60	Intermediate/Peak
Facility 311	Mecklenburg	NC	Solar	4.00	Intermediate/Peak
Facility 312	Guilford	NC	Solar	2.50	Intermediate/Peak
Facility 313	Macon	NC	Solar	3.00	Intermediate/Peak
Facility 314	Mecklenburg	NC	Solar	1.75	Intermediate/Peak
Facility 315	Stokes	NC	Solar	2.58	Intermediate/Peak
Facility 316	Polk	NC	Solar	6.65	Intermediate/Peak
Facility 317	Alamance	NC	Solar	2.00	Intermediate/Peak
Facility 318	Alamance	NC	Solar	4.90	Intermediate/Peak
Facility 319	Durham	NC	Solar	2.21	Intermediate/Peak
Facility 320	Mecklenburg	NC	Solar	1.40	Intermediate/Peak
Facility 321	Rockingham	NC	Solar	0.76	Intermediate/Peak
Facility 322	Rockingham	NC	Solar	90.00	Intermediate/Peak
Facility 323	Jackson	NC	Solar	2.58	Intermediate/Peak
Facility 324	Rutherford	NC	Solar	4.18	Intermediate/Peak
Facility 325	Durham- NE	NC	Solar	2.21	Intermediate/Peak
Facility 326	Iredell	NC	Solar	7.96	Intermediate/Peak
Facility 327	Wilkes	NC	Solar	4.20	Intermediate/Peak
Facility 328	Transylvania	NC	Solar	0.70	Intermediate/Peak
Facility 329	Henderson	NC	Solar	4.00	Intermediate/Peak
Facility 330	Durham	NC	Solar	2.48	Intermediate/Peak
Facility 331	Durham	NC	Solar	1.25	Intermediate/Peak
Facility 332		NC	Solar	3.23	Intermediate/Peak
Facility 333	Orange	NC	Solar	6.45	Intermediate/Peak
Facility 334		NC	Solar	3.60	Intermediate/Peak
Facility 335	Alamance	NC	Solar	2.00	Intermediate/Peak
Facility 336	Jackson	NC	Solar	3.00	Intermediate/Peak

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC kW)	Designation
Facility 337	Orange	NC	Solar	4.00	Intermediate/Peak
Facility 338	Durham	NC	Solar	3.00	Intermediate/Peak
Facility 339		NC	Solar	2.58	Intermediate/Peak
Facility 340	Alamance	NC	Solar	3.24	Intermediate/Peak
Facility 341	Rowan	NC	Solar	4.00	Intermediate/Peak
Facility 342	Cherokee	NC	Solar	7.60	Intermediate/Peak
Facility 343	Forsyth	NC	Solar	3.99	Intermediate/Peak
Facility 344	Wake	NC	Solar	2.50	Intermediate/Peak
Facility 345	Cabarrus	NC	Solar	9.80	Intermediate/Peak
Facility 346	Henderson	NC	Solar	4.00	Intermediate/Peak
Facility 347	Guilford	NC	Solar	4.00	Intermediate/Peak
Facility 348	Orange	NC	Solar	9.80	Intermediate/Peak
Facility 349	Orange	NC	Solar	4.00	Intermediate/Peak
Facility 350	Yadkin	NC	Solar	4.00	Intermediate/Peak
Facility 351	Cleveland	NC	Wind	1.20	Intermediate/Peak
Facility 352	Durham	NC	Solar	3.60	Intermediate/Peak
Facility 353	Mecklenburg	NC	Solar	3.04	Intermediate/Peak
Facility 354	Durham	NC	Solar	3.44	Intermediate/Peak
Facility 355	Alamance	NC	Solar	2.00	Intermediate/Peak
Facility 356	Durham	NC	Solar	2.82	Intermediate/Peak
Facility 357	Randolph	NC	Solar	2.00	Intermediate/Peak
Facility 358	Guilford	NC	Solar	2.00	Intermediate/Peak
Facility 359	Forsyth	NC	Solar	2.85	Intermediate/Peak
Facility 360	Henderson	NC	Solar	6.45	Intermediate/Peak
Facility 361	Forsyth	NC	Solar	2.85	Intermediate/Peak
Facility 362	Henderson	NC	Solar	10.00	Intermediate/Peak
Facility 363	Orange	NC	Solar	7.80	Intermediate/Peak
Facility 364	Polk	NC	Solar	4.32	Intermediate/Peak
Facility 365	Henderson	NC	Solar	7.31	Intermediate/Peak
Facility 366	Union	NC	Solar	3.00	Intermediate/Peak
Facility 367	Henderson	NC	Solar	2.58	Intermediate/Peak
Facility 368	Iredell	NC	Solar	3.30	Intermediate/Peak
Facility 369	Forsyth	NC	Solar	6.00	Intermediate/Peak
Facility 370	Cabarrus	NC	Solar	4.30	Intermediate/Peak
Facility 371	Cabarrus	NC	Solar	9.00	Intermediate/Peak
Facility 372	Wilkes	NC	Solar	4.73	Intermediate/Peak
Facility 373	Catawba	NC	Solar	15.20	Intermediate/Peak
Facility 374	Catawba	NC	Solar	6.00	Intermediate/Peak
Facility 375	Durham	NC	Solar	6.00	Intermediate/Peak
Facility 376	McDowell	NC	Solar	0.76	Intermediate/Peak
Facility 377	Forsyth	NC	Solar	5.00	Intermediate/Peak
Facility 378	Rutherfordton	NC	Solar	0.86	Intermediate/Peak
Facility 379	Stokes	NC	Solar	4.30	Intermediate/Peak
Facility 380	Mecklenburg	NC	Solar	5.00	Intermediate/Peak
Facility 381	Orange	NC	Solar	1.20	Intermediate/Peak
Facility 382	Henderson	NC	Solar	2.28	Intermediate/Peak
Facility 383	Rockingham	NC	Solar	4.30	Intermediate/Peak
Facility 384	Burke	NC	Solar	2.00	Intermediate/Peak
Facility 385	Orange	NC	Solar	2.58	Intermediate/Peak
Facility 386	McDowell	NC	Solar	3.00	Intermediate/Peak
Facility 387	Stokes	NC	Solar	5.00	Intermediate/Peak
Facility 388	Durham	NC	Solar	3.25	Intermediate/Peak
Facility 389	Orange	NC	Solar	2.00	Intermediate/Peak
Facility 390	Macon	NC	Solar	1.44	Intermediate/Peak
Facility 391	Macon	NC	Wind	1.00	Intermediate/Peak
Facility 392	Iredell	NC	Solar	4.00	Intermediate/Peak

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC kW)	Designation
Facility 393	Surry	NC	Solar	4.60	Intermediate/Peak
Facility 394	Hickory	NC	Other*	500.00	Intermediate/Peak
Facility 395	Mecklenburg	NC	Solar	9.00	Intermediate/Peak
Facility 396	Charlotte	NC	Other*	200.00	Intermediate/Peak
Facility 397	Durham	NC	Other*	1000.00	Intermediate/Peak
Facility 398	Cherokee	NC	Solar	3.01	Intermediate/Peak
Facility 399	McDowell	NC	Solar	3.57	Intermediate/Peak
Facility 400	Burke	NC	Solar	2.58	Intermediate/Peak
Facility 401	Durham	NC	Solar	2.50	Intermediate/Peak
Facility 402	Durham	NC	Solar	7.00	Intermediate/Peak
Facility 403	Guilford	NC	Solar	3.68	Intermediate/Peak
Facility 404	Rowan	NC	Solar	2.00	Intermediate/Peak
Facility 405	Durham	NC	Solar	4.00	Intermediate/Peak
Facility 406	Forsyth	NC	Solar	4.20	Intermediate/Peak
Facility 407	Guilford	NC	Solar	35.48	Intermediate/Peak
Facility 408	Alexander	NC	Solar	1.94	Intermediate/Peak
Facility 409	Wake	NC	Solar	6.87	Intermediate/Peak
Facility 410	Forsyth	NC	Solar	6.00	Intermediate/Peak
Facility 411	Guilford	NC	Solar	4.91	Intermediate/Peak
Facility 412	Mecklenburg	NC	Solar	3.50	Intermediate/Peak
Facility 413	Henderson	NC	Hydroelectric	6.00	Baseload
Facility 414	Wilkesboro	NC	Other*	600.00	Intermediate/Peak
Facility 415	Durham	NC	Solar	3.84	Intermediate/Peak
Facility 416	Henderson	NC	Solar	2.50	Intermediate/Peak
Facility 417	Forsyth	NC	Solar	2.58	Intermediate/Peak
Facility 418	Cleveland	NC	Solar	135.00	Intermediate/Peak
Facility 419	Durham	NC	Solar	2.15	Intermediate/Peak
Facility 420	Orange	NC	Solar	3.60	Intermediate/Peak
Facility 421	Alamance	NC	Solar	2.10	Intermediate/Peak
Facility 422	Mecklenburg	NC	Solar	6.75	Intermediate/Peak
Facility 423	Orange	NC	Solar	5.00	Intermediate/Peak
Facility 424	Orange	NC	Solar	2.40	Intermediate/Peak
Facility 425	Orange	NC	Solar	5.56	Intermediate/Peak
Facility 426	Rowan	NC	Solar	1.70	Intermediate/Peak
Facility 427	Union	NC	Solar	2.94	Intermediate/Peak
Facility 428	Guilford	NC	Solar	3.00	Intermediate/Peak
Facility 429	Davie	NC	Solar	7.85	Intermediate/Peak
Facility 430	Orange	NC	Solar	4.00	Intermediate/Peak
Facility 431	Durham	NC	Solar	5.16	Intermediate/Peak
Facility 432	Guilford	NC	Solar	4.00	Intermediate/Peak
Facility 433	Durham	NC	Solar	3.00	Intermediate/Peak
Facility 434	Davidson	NC	Solar	3.45	Intermediate/Peak
Facility 435	Mecklenburg	NC	Solar	2.58	Intermediate/Peak
Facility 436	Orange	NC	Solar	4.00	Intermediate/Peak
Facility 437	Cleveland	NC	Solar	4.70	Intermediate/Peak
Facility 438	Mecklenburg	NC	Solar	3.50	Intermediate/Peak
Facility 439	Mecklenburg	NC	Solar	4.00	Intermediate/Peak
Facility 440	Iredell	NC	Solar	60.00	Intermediate/Peak
Facility 441	Wake	NC	Solar	2.21	Intermediate/Peak
Facility 442	Randolph	NC	Solar	2.58	Intermediate/Peak
Facility 443	Alamance	NC	Solar	2.40	Intermediate/Peak
Facility 444	Forsyth	NC	Solar	3.15	Intermediate/Peak
Facility 445	Henderson	NC	Solar	2.70	Intermediate/Peak
Facility 446	Wake	NC	Solar	2.21	Intermediate/Peak
Facility 447	Orange	NC	Solar	5.16	Intermediate/Peak
Facility 448	Mecklenburg	NC	Solar	3.15	Intermediate/Peak

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC kW)	Designation
Facility 449	Mecklenburg	NC	Solar	3.44	Intermediate/Peak
Facility 450	Mecklenburg	NC	Solar	0.70	Intermediate/Peak
Facility 451	Surry	NC	Solar	1000.00	Intermediate/Peak
Facility 452	Rockingham	NC	Hydroelectric	1275.00	Baseload
Facility 453	Rockingham	NC	Hydroelectric	951.00	Baseload
Facility 454	Marion	NC	Other*	650.00	Intermediate/Peak
Facility 455	Hickory	NC	Other*	500.00	Intermediate/Peak
Facility 456	Catawba	NC	Solar	8.17	Intermediate/Peak
Facility 457	Mecklenburg	NC	Solar	49.00	Intermediate/Peak
Facility 458	Charlotte	NC	Other*	2200.00	Intermediate/Peak
Facility 459	Mecklenburg	NC	Solar	12.00	Intermediate/Peak
Facility 460	Hendersonville	NC	Other*	1000.00	Intermediate/Peak
Facility 461	Cabarrus	NC	Solar	4.00	Intermediate/Peak
Facility 462	Concord	NC	Other*	2950.00	Intermediate/Peak
Facility 463	Rutherford	NC	Solar	1.96	Intermediate/Peak
Facility 464	Mecklenburg	NC	Solar	5.76	Intermediate/Peak
Facility 465	Orange	NC	Solar	1.32	Intermediate/Peak
Facility 466	Yadkin	NC	Solar	7.80	Intermediate/Peak
Facility 467	Yadkin	NC	Solar	7.10	Intermediate/Peak
Facility 468	Mecklenburg	NC	Solar	1.89	Intermediate/Peak
Facility 469	Jackson	NC	Solar	2.76	Intermediate/Peak
Facility 470	Yadkin	NC	Solar	6.00	Intermediate/Peak
Facility 471	Rutherford	NC	Solar	1.94	Intermediate/Peak
Facility 472	Iredell	NC	Solar	2.80	Intermediate/Peak
Facility 473	Davidson	NC	Solar	4.32	Intermediate/Peak
Facility 474	Durham	NC	Solar	3.23	Intermediate/Peak
Facility 475	Gaston	NC	Hydroelectric	1800.00	Baseload
Facility 476	Davie	NC	Solar	5000.00	Intermediate/Peak
Facility 477	Durham	NC	Solar	3.00	Intermediate/Peak
Facility 478	Stokes	NC	Solar	4.00	Intermediate/Peak
Facility 479	Greensboro	NC	Other*	700.00	Intermediate/Peak
Facility 480	Greensboro	NC	Other*	2500.00	Intermediate/Peak
Facility 481	Greensboro	NC	Other*	1280.00	Intermediate/Peak
Facility 482	Durham	NC	Landfill Gas	3180.00	Baseload
Facility 483	Mecklenburg	NC	Solar	4.80	Intermediate/Peak
Facility 484	Durham	NC	Solar	2.58	Intermediate/Peak
Facility 485	Mecklenburg	NC	Solar	4.00	Intermediate/Peak
Facility 486	Catawba	NC	Solar	5.00	Intermediate/Peak
Facility 487	Gaston	NC	Solar	635.00	Intermediate/Peak
Facility 488	Mecklenburg	NC	Solar	30.00	Intermediate/Peak
Facility 489	Winston-Salem	NC	Other*	400.00	Intermediate/Peak
Facility 490	Durham	NC	Solar	28.00	Intermediate/Peak
Facility 491	Concord	NC	Other*	680.00	Intermediate/Peak
Facility 492	Butner	NC	Other*	1250.00	Intermediate/Peak
Facility 493	Morganton	NC	Other*	200.00	Intermediate/Peak
Facility 494	Catawba	NC	Solar	135.00	Intermediate/Peak
Facility 495	Orange	NC	Solar	3.60	Intermediate/Peak
Facility 496	Union	NC	Solar	2.63	Intermediate/Peak
Facility 497	Cabarrus	NC	Solar	4.00	Intermediate/Peak
Facility 498	Rowan	NC	Solar	10.00	Intermediate/Peak
Facility 499	Polk	NC	Hydroelectric	5500.00	Baseload
Facility 500	Alamance	NC	Solar	221.76	Intermediate/Peak
Facility 501	Orange	NC	Solar	18.48	Intermediate/Peak
Facility 502	Orange	NC	Solar	18.48	Intermediate/Peak
Facility 503	Davidson	NC	Solar	1500.00	Intermediate/Peak
Facility 504	Mecklenburg	NC	Solar	8.40	Intermediate/Peak

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC kW)	Designation
Facility 505	Carrboro	NC	Other*	500.00	Intermediate/Peak
Facility 506	Chapel Hill	NC	Other*	1135.00	Intermediate/Peak
Facility 507	Chapel Hill	NC	Other*	500.00	Intermediate/Peak
Facility 508	Chapel Hill	NC	Other*	2000.00	Intermediate/Peak
Facility 509	Orange	NC	Solar	5.30	Intermediate/Peak
Facility 510	Orange	NC	Solar	6.00	Intermediate/Peak
Facility 511	Hendersonville	NC	Other*	500.00	Intermediate/Peak
Facility 512	Fletcher	NC	Other*	1000.00	Intermediate/Peak
Facility 513	McDowell	NC	Solar	4.68	Intermediate/Peak
Facility 514	Guilford	NC	Solar	3.01	Intermediate/Peak
Facility 515	Macon	NC	Solar	1.92	Intermediate/Peak
Facility 516	Orange	NC	Solar	3.78	Intermediate/Peak
Facility 517	Rowan	NC	Solar	7.20	Intermediate/Peak
Facility 518	Rowan	NC	Solar	5.60	Intermediate/Peak
Facility 519	Alamance	NC	Solar	2.00	Intermediate/Peak
Facility 520	Cabarrus	NC	Engine Dynamometer	N/A	Intermediate/Peak
Facility 521	Durham	NC	Solar	4.30	Intermediate/Peak
Facility 522	Guilford	NC	Solar	2.70	Intermediate/Peak
Facility 523	Alamance	NC	Solar	3.00	Intermediate/Peak
Facility 524	Forsyth	NC	Solar	6.00	Intermediate/Peak
Facility 525	Durham	NC	Solar	3.36	Intermediate/Peak
Facility 526	Rutherford	NC	Solar	5.00	Intermediate/Peak
Facility 527	Rutherford	NC	Solar	3.68	Intermediate/Peak
Facility 528	Transylvania	NC	Solar	3.00	Intermediate/Peak
Facility 529	Rowan	NC	Solar	2.58	Intermediate/Peak
Facility 530	Cleveland	NC	Hydroelectric	600.00	Baseload
Facility 531	Winston-Salem	NC	Other*	750.00	Intermediate/Peak
Facility 532	Guilford	NC	Solar	1.80	Intermediate/Peak
Facility 533	Jackson	NC	Solar	9.00	Intermediate/Peak
Facility 534	Mebane	NC	Other*	400.00	Intermediate/Peak
Facility 535	Matthews	NC	Other*	1450.00	Intermediate/Peak
Facility 536	Huntersville	NC	Other*	3200.00	Intermediate/Peak
Facility 537	Mecklenburg	NC	Solar	33.12	Intermediate/Peak
Facility 538	Mecklenburg	NC	Solar	52.47	Intermediate/Peak
Facility 539	Jackson	NC	Solar	4.00	Intermediate/Peak
Facility 540	Mecklenburg	NC	Solar	8.80	Intermediate/Peak
Facility 541	Orange	NC	Solar	4.00	Intermediate/Peak
Facility 542	Mecklenburg	NC	Solar	2.70	Intermediate/Peak
Facility 543	Durham	NC	Solar	7.00	Intermediate/Peak
Facility 544	Mecklenburg	NC	Solar	7.60	Intermediate/Peak
Facility 545	Mecklenburg	NC	Solar	4.10	Intermediate/Peak
Facility 546	Orange	NC	Solar	1.20	Intermediate/Peak
Facility 547	Davie	NC	Solar	9.88	Intermediate/Peak
Facility 548	Mecklenburg	NC	Solar	2.00	Intermediate/Peak
Facility 549	Polk	NC	Solar	5.18	Intermediate/Peak
Facility 550	Orange	NC	Solar	3.00	Intermediate/Peak
Facility 551	Orange	NC	Solar	1.71	Intermediate/Peak
Facility 552	Durham	NC	Solar	1.20	Intermediate/Peak
Facility 553	Polk	NC	Solar	1.72	Intermediate/Peak
Facility 554	Mecklenburg	NC	Solar	18.06	Intermediate/Peak
Facility 555	Henderson	NC	Solar	2.50	Intermediate/Peak
Facility 556	RTP	NC	Other*	350.00	Intermediate/Peak
Facility 557	Forsyth	NC	Solar	1.94	Intermediate/Peak
Facility 558	Randolph	NC	Solar	2.30	Intermediate/Peak
Facility 559	Durham	NC	Solar	4.00	Intermediate/Peak
Facility 560	Stanly	NC	Solar	5.17	Intermediate/Peak

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC kW)	Designation
Facility 561	Gaston	NC	Solar	4.00	Intermediate/Peak
Facility 562	Forsyth	NC	Solar	4.30	Intermediate/Peak
Facility 563	Catawba	NC	Solar	3.00	Intermediate/Peak
Facility 564	Wilkes	NC	Solar	3.68	Intermediate/Peak
Facility 565	Rural Hall	NC	Other*	1050.00	Intermediate/Peak
Facility 566	Mecklenburg	NC	Solar	4.70	Intermediate/Peak
Facility 567	Jackson	NC	Solar	9.90	Intermediate/Peak
Facility 568	Franklin	NC	Solar	5.00	Intermediate/Peak
Facility 569	Mecklenburg	NC	Solar	2.50	Intermediate/Peak
Facility 570	Henderson	NC	Solar	4.00	Intermediate/Peak
Facility 571	Orange	NC	Solar	3.50	Intermediate/Peak
Facility 572	Guilford	NC	Solar	1.10	Intermediate/Peak
Facility 573	Guilford	NC	Solar	4.00	Intermediate/Peak
Facility 574	Mecklenburg	NC	Solar	5.00	Intermediate/Peak
Facility 575	Henderson	NC	Solar	0.76	Intermediate/Peak
Facility 576	Union	NC	Solar	1.00	Intermediate/Peak
Facility 577	Mecklenburg	NC	Solar	2.58	Intermediate/Peak
Facility 578	Alamance	NC	Solar	5.50	Intermediate/Peak
Facility 579	Stanly	NC	Solar	5.16	Intermediate/Peak
Facility 580	Union	NC	Solar	7.00	Intermediate/Peak
Facility 581	Union	NC	Solar	2.48	Intermediate/Peak
Facility 582	Macon	NC	Solar	5.94	Intermediate/Peak
Facility 583	Randolph	NC	Solar	4.00	Intermediate/Peak
Facility 584	Rowan	NC	Solar	6.45	Intermediate/Peak
Facility 585	Durham	NC	Solar	4.62	Intermediate/Peak
Facility 586	Wilkes	NC	Hydroelectric	200.00	Baseload
Facility 587	Iredell	NC	Solar	3.00	Intermediate/Peak
Facility 588	Iredell	NC	Engine Dynamometer	N/A	Intermediate/Peak
Facility 589	Henderson	NC	Solar	9.00	Intermediate/Peak
Facility 590	Iredell	NC	Solar	2.94	Intermediate/Peak
Facility 591	Transylvania	NC	Solar	3.00	Intermediate/Peak
Facility 592	Henderson	NC	Solar	3.44	Intermediate/Peak
Facility 593	Forsyth	NC	Landfill Gas	4750.00	Baseload
Facility 594	Durham	NC	Solar	5.00	Intermediate/Peak
Facility 595	Mecklenburg	NC	Solar	4.73	Intermediate/Peak
Facility 596	Mecklenburg	NC	Solar	10.80	Intermediate/Peak
Facility 597	Alamance	NC	Solar	3.44	Intermediate/Peak
Facility 598	Alamance	NC	Solar	2.40	Intermediate/Peak
Facility 599	Rutherford	NC	Solar	3.60	Intermediate/Peak
Facility 600	Alamance	NC	Solar	24.00	Intermediate/Peak
Facility 601	Orange	NC	Solar	2.58	Intermediate/Peak
Facility 602	Caswell	NC	Solar	2.82	Intermediate/Peak
Facility 603	Mecklenburg	NC	Solar	20.00	Intermediate/Peak
Facility 604	Orange	NC	Solar	2.40	Intermediate/Peak
Facility 605	Guilford	NC	Solar	5.46	Intermediate/Peak
Facility 606	Catawba	NC	Solar	2.58	Intermediate/Peak
Facility 607	McDowell	NC	Solar	1.02	Intermediate/Peak
Facility 608	Durham	NC	Solar	3.50	Intermediate/Peak
Facility 609	Cabarrus	NC	Solar	3.00	Intermediate/Peak
Facility 610	Orange	NC	Solar	2.00	Intermediate/Peak
Facility 611	Durham	NC	Solar	4.00	Intermediate/Peak
Facility 612	Henderson	NC	Solar	5.00	Intermediate/Peak
Facility 613	Alexander	NC	Solar	2.58	Intermediate/Peak
Facility 614	Mcdowell	NC	Solar	3.00	Intermediate/Peak
Facility 615	Guilford	NC	Solar	2.58	Intermediate/Peak
Facility 616	Cabarrus	NC	Solar	4500.00	Intermediate/Peak

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC kW)	Designation
Facility 617	Durham	NC	Solar	101.20	Intermediate/Peak
Facility 618	Guilford	NC	Solar	12.00	Intermediate/Peak
Facility 619	Forsyth	NC	Solar	10.00	Intermediate/Peak
Facility 620	Butner	NC	Other*	750.00	Intermediate/Peak
Facility 621	Davie	NC	Hydroelectric	1500.00	Baseload
Facility 622	Surry	NC	Solar	9.87	Intermediate/Peak
Facility 623	Forsyth	NC	Solar	4.00	Intermediate/Peak
Facility 624	Surry	NC	Solar	5.00	Intermediate/Peak
Facility 625	Orange	NC	Solar	8.60	Intermediate/Peak
Facility 626	Durham	NC	Solar	3.66	Intermediate/Peak
Facility 627	Durham	NC	Solar	2.04	Intermediate/Peak
Facility 628	Burke	NC	Solar	3.04	Intermediate/Peak
Facility 629	Iredell	NC	Solar	1.51	Intermediate/Peak
Facility 630	Rockingham	NC	Solar	4.73	Intermediate/Peak
Facility 631	Lincoln	NC	Hydroelectric	750.00	Baseload
Facility 632	Catawba	NC	Solar	4.41	Intermediate/Peak
Facility 633	Chatham	NC	Solar	3.84	Intermediate/Peak
Facility 634	Mecklenburg	NC	Solar	2.00	Intermediate/Peak
Facility 635	Orange	NC	Solar	5.00	Intermediate/Peak
Facility 636	Orange	NC	Solar	5.17	Intermediate/Peak
Facility 637	Alamance	NC	Solar	2.85	Intermediate/Peak
Facility 638	Orange	NC	Solar	9.00	Intermediate/Peak
Facility 639	Durham	NC	Solar	1.50	Intermediate/Peak
Facility 640	Transylvania	NC	Solar	3.36	Intermediate/Peak
Facility 641	RTP	NC	Other*	1825.00	Intermediate/Peak
Facility 642	Rockingham	NC	Solar	9.00	Intermediate/Peak
Facility 643	Forsyth	NC	Solar	6.00	Intermediate/Peak
Facility 644	Guilford	NC	Solar	21.40	Intermediate/Peak
Facility 645	Davidson	NC	Solar	15500.00	Intermediate/Peak
Facility 646	Transylvania	NC	Solar	6.00	Intermediate/Peak
Facility 647	Macon	NC	Solar	6.00	Intermediate/Peak
Facility 648	Orange	NC	Solar	9.24	Intermediate/Peak
Facility 649	Chatham	NC	Solar	4.41	Intermediate/Peak
Facility 650	Wake	NC	Solar	2.21	Intermediate/Peak
Facility 651	Catawba	NC	Solar	4.76	Intermediate/Peak
Facility 652	Orange	NC	Solar	4.00	Intermediate/Peak
Facility 653	Gaston	NC	Solar	1.14	Intermediate/Peak
Facility 654	Rockingham	NC	Solar	2.80	Intermediate/Peak
Facility 655	Swain	NC	Solar	5.00	Intermediate/Peak
Facility 656	Durham	NC	Solar	2.80	Intermediate/Peak
Facility 657	Durham	NC	Solar	5.00	Intermediate/Peak
Facility 658	Greensboro	NC	Other*	750.00	Intermediate/Peak
Facility 659	Greensboro	NC	Other*	250.00	Intermediate/Peak
Facility 660	Alamance	NC	Solar	8.60	Intermediate/Peak
Facility 661	Guilford	NC	Solar	2.15	Intermediate/Peak
Facility 662	Randolph	NC	Solar	20.00	Intermediate/Peak
Facility 663	Randolph	NC	Solar	52.00	Intermediate/Peak
Facility 664	Guilford	NC	Solar	5.00	Intermediate/Peak
Facility 665	Guilford	NC	Solar	175.00	Intermediate/Peak
Facility 666	Orange	NC	Solar	0.74	Intermediate/Peak
Facility 667	Henderson	NC	Solar & Wind	6.00	Intermediate/Peak
Facility 668	Mecklenburg	NC	Solar	4.60	Intermediate/Peak
Facility 669	Mecklenburg	NC	Solar	250.00	Intermediate/Peak
Facility 670	Catawba	NC	Solar	4.70	Intermediate/Peak
Facility 671	Catawba	NC	Solar	4.70	Intermediate/Peak
Facility 672	Orange	NC	Solar	4.00	Intermediate/Peak

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC kW)	Designation
Facility 673	Durham	NC	Solar	2.28	Intermediate/Peak
Facility 674	Polk	NC	Solar	6.00	Intermediate/Peak
Facility 675	Alamance	NC	Solar	1.90	Intermediate/Peak
Facility 676		NC	Solar	4.58	Intermediate/Peak
Facility 677	Mecklenburg	NC	Solar	2.58	Intermediate/Peak
Facility 678	Henderson	NC	Solar	1.94	Intermediate/Peak
Facility 679	Union	NC	Solar	4.30	Intermediate/Peak
Facility 680	Randolph	NC	Solar	3.98	Intermediate/Peak
Facility 681	Cabarrus	NC	Solar	4.05	Intermediate/Peak
Facility 682	Cabarrus	NC	Solar	4.00	Intermediate/Peak
Facility 683	Swain	NC	Solar	2.52	Intermediate/Peak
Facility 684	Rutherfordton	NC	Solar	2.80	Intermediate/Peak
Facility 685	Orange	NC	Solar	5.00	Intermediate/Peak
Facility 686	Mecklenburg	NC	Solar	4.95	Intermediate/Peak
Facility 687	Durham	NC	Solar	4.95	Intermediate/Peak
Facility 688	Orange	NC	Solar	1.48	Intermediate/Peak
Facility 689	Randolph	NC	Solar	4.00	Intermediate/Peak
Facility 690	Orange	NC	Solar	9.00	Intermediate/Peak
Facility 691	Orange	NC	Solar	9.00	Intermediate/Peak
Facility 692	Guilford	NC	Solar	3.01	Intermediate/Peak
Facility 693	Mecklenburg	NC	Solar	3.29	Intermediate/Peak
Facility 694	Burke	NC	Solar	2.58	Intermediate/Peak
Facility 695	Lincoln	NC	Solar	9.00	Intermediate/Peak
Facility 696	Orange	NC	Solar	3.80	Intermediate/Peak
Facility 697	Rutherford	NC	Hydroelectric	3600.00	Baseload
Facility 698	North Wilkesboro	NC	Other*	1250.00	Intermediate/Peak
Facility 699	Jackson	NC	Solar	5.00	Intermediate/Peak
Facility 700	Valdese	NC	Other*	600.00	Intermediate/Peak
Facility 701	Wilkesboro	NC	Other*	750.00	Intermediate/Peak
Facility 702	Yadkinville	NC	Other*	1200.00	Intermediate/Peak
Facility 703	Reidsville	NC	Other*	750.00	Intermediate/Peak
Facility 704	Mooresville	NC	Other*	750.00	Intermediate/Peak
Facility 705	Brevard	NC	Other*	1000.00	Intermediate/Peak
Facility 706	Guilford	NC	Solar	30.00	Intermediate/Peak
Facility 707	Cherokee	NC	Other*	12500.00	Intermediate/Peak
Facility 708	Mecklenburg	NC	Solar	18.00	Intermediate/Peak
Facility 709	Durham	NC	Solar	4.00	Intermediate/Peak
Facility 710	Catawba	NC	Solar	5000.00	Intermediate/Peak
Facility 711	North Wilkesboro	NC	Other*	155.00	Intermediate/Peak
Facility 712	Mecklenburg	NC	Solar	4.80	Intermediate/Peak
Facility 713	Union	NC	Solar	6.02	Intermediate/Peak
Facility 714	Orange	NC	Solar	20.00	Intermediate/Peak
Facility 715		NC	Landfill Gas	1059.00	Baseload
Facility 716	Durham	NC	Solar	112.00	Intermediate/Peak
Facility 717	Durham	NC	Solar	51.00	Intermediate/Peak
Facility 718	Durham	NC	Solar	4.00	Intermediate/Peak
Facility 719	Chatham	NC	Solar	2.70	Intermediate/Peak
Facility 720	Salisbury	NC	Other*	1500.00	Intermediate/Peak
Facility 721	Mecklenburg	NC	Solar	5.70	Intermediate/Peak
Facility 722	Mecklenburg	NC	Solar	4.00	Intermediate/Peak
Facility 723	Forsyth	NC	Solar	1.92	Intermediate/Peak
Facility 724	Mecklenburg	NC	Solar	27.47	Intermediate/Peak
Facility 725	Orange	NC	Solar	14.51	Intermediate/Peak
Facility 726	Winston-Salem	NC	Other*	3750.00	Intermediate/Peak
Facility 727	Winston-Salem	NC	Other*	3000.00	Intermediate/Peak
Facility 728	Winston-Salem	NC	Other*	3000.00	Intermediate/Peak

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC kW)	Designation
Facility 729	Winston-Salem	NC	Other*	500.00	Intermediate/Peak
Facility 730	Rowan	NC	Solar	150.00	Intermediate/Peak
Facility 731	Rockingham	NC	Solar	2.00	Intermediate/Peak
Facility 732	Iredell	NC	Solar	1.40	Intermediate/Peak
Facility 733	Cherokee	NC	Solar	8.20	Intermediate/Peak
Facility 734	Orange	NC	Solar	4.32	Intermediate/Peak
Facility 735	Watauga	NC	Landfill Gas	186.00	Baseload
Facility 736	Davie	NC	Solar	0.70	Intermediate/Peak
Facility 737	Winston-Salem	NC	Other*	2000.00	Intermediate/Peak
Facility 738	Wilkes	NC	Solar	2.85	Intermediate/Peak
Facility 739	Elkin	NC	Other*	500.00	Intermediate/Peak
Facility 740	Polk	NC	Solar	5.00	Intermediate/Peak
Facility 741	Transylvania	NC	Solar	0.65	Intermediate/Peak
Facility 742	Wilkes	NC	Wind	2.40	Intermediate/Peak
Facility 743	Wilkes	NC	Landfill Gas	70.00	Baseload
Facility 744	Guilford	NC	Solar	4.52	Intermediate/Peak
Facility 745	Cleveland	NC	Solar	2.50	Intermediate/Peak
Facility 746	Orange	NC	Solar	2.30	Intermediate/Peak
Facility 747	Orange	NC	Solar	5.00	Intermediate/Peak
Facility 748	Mecklenburg	NC	Solar	2.41	Intermediate/Peak
Facility 749	Macon	NC	Solar	3.00	Intermediate/Peak
Facility 750	Forsyth	NC	Solar	2.94	Intermediate/Peak
Facility 751	Orange	NC	Solar	2.00	Intermediate/Peak
Facility 752	Guilford	NC	Solar	4.80	Intermediate/Peak
Facility 753	Durham	NC	Solar	3.00	Intermediate/Peak
Facility 754	Jackson	NC	Solar	6.00	Intermediate/Peak
Facility 755	Orange	NC	Solar	4.00	Intermediate/Peak
Facility 756	Guilford	NC	Solar	3.00	Intermediate/Peak
Facility 757	Forsyth	NC	Solar	3.30	Intermediate/Peak
Facility 758	Forsyth	NC	Landfill Gas	2400.00	Baseload
Facility 759	Mecklenburg	NC	Solar	4.00	Intermediate/Peak
Facility 760	Union	NC	Solar	6.00	Intermediate/Peak
Facility 761	Davidson	NC	Solar	82.00	Intermediate/Peak
Facility 762	Transylvania	NC	Solar	4.00	Intermediate/Peak

Note: Data provided in Table H-3 reflects nameplate capacity for the facility.

Table H-4 Non-Utility Generation- South Carolina

SOUTH CAROLINA GENERATORS

Facility Name	City/County	State	Primary Fuel Type	Capacity (kW)	Designation
Facility 763	Cherokee	SC	Natural Gas	100000.00	Intermediate/Peak
Facility 764	Greenville	SC	Solar	21.00	Intermediate/Peak
Facility 765	Spartanburg	SC	Solar	15.00	Intermediate/Peak
Facility 766		SC	Solar	0.76	Intermediate/Peak
Facility 767	Anderson	SC	Solar	10.00	Intermediate/Peak
Facility 768	Greenville	SC	Hydroelectric	600.00	Baseload
Facility 769	Laurens	SC	Hydroelectric	6300.00	Baseload
Facility 770	Greenville	SC	Solar	1.94	Intermediate/Peak
Facility 771	Pickens	SC	Solar	2.35	Intermediate/Peak
Facility 772	Spartanburg	SC	Solar	94.08	Intermediate/Peak
Facility 773	Spartanburg	SC	Solar	0.76	Intermediate/Peak
Facility 774	Greenville	SC	Solar	2.15	Intermediate/Peak
Facility 775	Spartanburg	SC	Solar	5.52	Intermediate/Peak
Facility 776	Greenville	SC	Solar	1.68	Intermediate/Peak
Facility 777	York	SC	Solar	2.80	Intermediate/Peak
Facility 778	Lancaster	SC	Solar	5.00	Intermediate/Peak
Facility 779	Pickens	SC	Solar	11.00	Intermediate/Peak
Facility 780	Oconee	SC	Solar	3.60	Intermediate/Peak
Facility 781	Greenville	SC	Solar	1.80	Intermediate/Peak
Facility 782	Pickens	SC	Solar	42.00	Intermediate/Peak
Facility 783	Laurens	SC	Solar	6.00	Intermediate/Peak
Facility 784	Greenville	SC	Solar	5.00	Intermediate/Peak
Facility 785	Greenwood	SC	Other*	1500.00	Intermediate/Peak
Facility 786	Spartanburg	SC	Hydroelectric	1250.00	Baseload
Facility 787	Pickens	SC	Solar	4.50	Intermediate/Peak
Facility 788	Laurens	SC	Solar	0.76	Intermediate/Peak
Facility 789	Greenville	SC	Solar	2.28	Intermediate/Peak
Facility 790	Spartanburg	SC	Solar	3.01	Intermediate/Peak
Facility 791	Greenwood	SC	Solar	2.76	Intermediate/Peak
Facility 792	Spartanburg	SC	Solar	0.74	Intermediate/Peak
Facility 793	Greenville	SC	Solar	2.53	Intermediate/Peak
Facility 794	Spartanburg	SC	Solar	2.80	Intermediate/Peak
Facility 795		SC	Solar	N/A	Intermediate/Peak
Facility 796	York	SC	Solar	2.85	Intermediate/Peak
Facility 797	Pickens	SC	Solar	9.00	Intermediate/Peak
Facility 798	Greenville	SC	Solar	0.76	Intermediate/Peak
Facility 799	Oconee	SC	Solar	10.08	Intermediate/Peak
Facility 800	Spartanburg	SC	Engine Dynamometer	N/A	Intermediate/Peak
Facility 801	Greenville	SC	Solar	29.83	Intermediate/Peak
Facility 802	Greenville	SC	Solar	100.00	Intermediate/Peak
Facility 803	Greenville	SC	Solar	4.30	Intermediate/Peak
Facility 804	Spartanburg	SC	Solar	2.15	Intermediate/Peak
Facility 805	Laurens	SC	Solar	5.64	Intermediate/Peak
Facility 806	Spartanburg	SC	Solar	3.00	Intermediate/Peak
Facility 807	Spartanburg	SC	Landfill Gas	3200.00	Baseload
Facility 808	Greenville	SC	Solar	30.10	Intermediate/Peak
Facility 809		SC	Solar	5.16	Intermediate/Peak
Facility 810	Spartanburg	SC	Hydroelectric	1600.00	Baseload
Facility 811	Greenville	SC	Solar	49.00	Intermediate/Peak
Facility 812	Oconee	SC	Solar	56.70	Intermediate/Peak
Facility 813	Greenville	SC	Solar	4.30	Intermediate/Peak
Facility 814	York	SC	Solar	2.10	Intermediate/Peak
Facility 815	Spartanburg	SC	Solar	0.76	Intermediate/Peak
Facility 816	Spartanburg	SC	Solar	0.19	Intermediate/Peak
Facility 817	Oconee	SC	Solar	4.00	Intermediate/Peak
Facility 818	Laurens	SC	Solar	1.94	Intermediate/Peak
Facility 819	Pickens	SC	Solar	1.05	Intermediate/Peak

Facility Name	City/County	State	Primary Fuel Type	Capacity (kW)	Designation
Facility 820	York	SC	Solar	5.41	Intermediate/Peak
Facility 821	Greenville	SC	Solar	8.00	Intermediate/Peak
Facility 822	Greenville	SC	Solar	4.84	Intermediate/Peak
Facility 823	Pickens	SC	Solar	4.20	Intermediate/Peak
Facility 824	Pickens	SC	Solar	2.62	Intermediate/Peak
Facility 825	York	SC	Solar	2.99	Intermediate/Peak
Facility 826	Greenville	SC	Solar	5.89	Intermediate/Peak
Facility 827	Greenville	SC	Solar	3.36	Intermediate/Peak
Facility 828	Pickens	SC	Solar	4.00	Intermediate/Peak
Facility 829	Greenville	SC	Solar	2.94	Intermediate/Peak
Facility 830	Pickens	SC	Solar	15.60	Intermediate/Peak
Facility 831	Greenville	SC	Solar	1.94	Intermediate/Peak
Facility 832	Oconee	SC	Solar	4.73	Intermediate/Peak
Facility 833	Clinton	SC	Other*	447.00	Intermediate/Peak
Facility 834	Anderson	SC	Solar	3.44	Intermediate/Peak
Facility 835	Greenville	SC	Solar	1.30	Intermediate/Peak
Facility 836	Spartanburg	SC	Landfill Gas	1600.00	Baseload
Facility 837	Spartanburg	SC	Solar	3.85	Intermediate/Peak
Facility 838	Spartanburg	SC	Solar	0.86	Intermediate/Peak
Facility 839	Laurens	SC	Solar	8.60	Intermediate/Peak
Facility 840	Spartanburg	SC	Solar	2.85	Intermediate/Peak
Facility 841	Greenville	SC	Solar	3.82	Intermediate/Peak
Facility 842	Spartanburg	SC	Solar	6.00	Intermediate/Peak
Facility 843	Spartanburg	SC	Solar	3.78	Intermediate/Peak
Facility 844	Greenville	SC	Solar	1.04	Intermediate/Peak
Facility 845	Anderson	SC	Solar	6.14	Intermediate/Peak
Facility 846	Spartanburg	SC	Solar	0.74	Intermediate/Peak
Facility 847	Greenville	SC	Solar	14.00	Intermediate/Peak
Facility 848	Anderson	SC	Hydroelectric	3500.00	Baseload
Facility 849	Greenville	SC	Hydroelectric	2400.00	Baseload
Facility 850	Laurens	SC	Hydroelectric	1500.00	Baseload
Facility 851	Greenville	SC	Solar	3.01	Intermediate/Peak
Facility 852	Greenwood	SC	Solar	7.52	Intermediate/Peak
Facility 853	Anderson	SC	Hydroelectric	2020.00	Baseload
Facility 854	Anderson	SC	Hydroelectric	3300.00	Baseload
Facility 855	Pickens	SC	Solar	6.58	Intermediate/Peak
Facility 856	Greenville	SC	Solar	2.38	Intermediate/Peak
Facility 857	Spartanburg	SC	Solar	1.47	Intermediate/Peak
Facility 858	Greenville	SC	Solar	6.72	Intermediate/Peak
Facility 859	York	SC	Solar	2.50	Intermediate/Peak
Facility 860	Greenville	SC	Solar	3.01	Intermediate/Peak
Facility 861	Anderson	SC	Solar	2.38	Intermediate/Peak
Facility 862	Chester	SC	Solar	2.47	Intermediate/Peak
Facility 863	Greenville	SC	Solar	4.68	Intermediate/Peak
Facility 864	York	SC	Solar	0.70	Intermediate/Peak
Facility 865	Kershaw	SC	Other*	1875.00	Intermediate/Peak
Facility 866	Greenville	SC	Solar	19.40	Intermediate/Peak
Facility 867	Spartanburg	SC	Other*	500.00	Intermediate/Peak
Facility 868	Spartanburg	SC	Solar	2.20	Intermediate/Peak
Facility 869	Spartanburg	SC	Wind	1.20	Intermediate/Peak
Facility 870	Spartanburg	SC	Other*	2432.00	Intermediate/Peak
Facility 871	Spartanburg	SC	Hydroelectric	1000.00	Baseload
Facility 872	Greenville	SC	Solar	8.00	Intermediate/Peak
Facility 873	Greenville	SC	Solar	0.76	Intermediate/Peak
Facility 874	Spartanburg	SC	Solar	4.20	Intermediate/Peak
Facility 875	Greenville	SC	Solar	3.00	Intermediate/Peak
Facility 876	Greenville	SC	Solar	4.00	Intermediate/Peak

Facility Name	City/County	State	Primary Fuel Type	Capacity (kW)	Designation
Facility 877	Greenville	SC	Solar	5.16	Intermediate/Peak
Facility 878	York	SC	Solar	2.50	Intermediate/Peak
Facility 879	York	SC	Solar	7.00	Intermediate/Peak
Facility 880	Spartanburg	SC	Solar	1.52	Intermediate/Peak
Facility 881	York	SC	Solar	8.09	Intermediate/Peak
Facility 882	Greenville	SC	Solar	1.80	Intermediate/Peak
Facility 883	Anderson	SC	Solar	2.14	Intermediate/Peak
Facility 884	Greenville	SC	Solar	6.00	Intermediate/Peak
Facility 885	Greenville	SC	Solar	4.00	Intermediate/Peak
Facility 886	Greenville	SC	Solar	2.10	Intermediate/Peak
Facility 887	Anderson	SC	Solar	3.60	Intermediate/Peak

Note: Data provided in Table H-4 reflects nameplate capacity for the facility.

APPENDIX I: TRANSMISSION PLANNED OR UNDER CONSTRUCTION

This appendix lists the planned transmission line additions and discusses the adequacy of DEC's transmission system. The transmission additions are sub-divided into two (2) tables. Table I-1 lists the transmission line projects that DEC has agreed to construct as part of its merger commitments. Table I-2 lists the line projects that were planned to meet reliability needs. This appendix also provides information pursuant to the North Carolina Utility Commission Rule R8-62.

Table I-1: Duke/Progress Merger Mitigation Project

YEAR	PROJECT	CAPACITY
2014	Antioch 500/230 KV Transformer Upgrades	1680 MVA/Transformer

Table I-2: DEC Transmission Line Additions (Non merger related)

YEAR	PROJECT	CAPACITY
	NONE	

Rule R8-62: Certificates of environmental compatibility and public convenience and necessity for the construction of electric transmission lines in North Carolina.

(p) Plans for the construction of transmission lines in North Carolina (161 kV and above) shall be incorporated in filings made pursuant to Commission Rule R8-60. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(1) For existing lines, the information required on FERC Form 1, pages 422, 423, 424, and 425, except that the information reported on pages 422 and 423 may be reported every five years.

Please refer to the Company's FERC Form No. 1 filed with NCUC in April, 2013.

(p) Plans for the construction of transmission lines in North Carolina (161 kV and above) shall be incorporated in filings made pursuant to Commission Rule R8-60. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(2) For lines under construction, the following:

a. Commission docket number;
b. Location of end point(s);
c. length;
d. range of right-of-way width;
e. range of tower heights;
f. number of circuits;
g. operating voltage;
h. design capacity;
i. date construction started;
j. projected in-service date;

There are presently no plans for construction of any 161 kV and above transmission lines.

DEC 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 DEC transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability. DEC works with DEP, NCEMC and ElectriCities to develop an annual NC Transmission Planning Collaborative (NCTPC) plan for the DEC and DEP systems in both North and South Carolina. In addition, transmission planning is coordinated with neighboring systems including South Carolina Electric & Gas (SCE&G) and Santee Cooper under a number of mechanisms including legacy interchange agreements between SCE&G, Santee Cooper, DEP, and DEC.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with DEC's 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 DEC – 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.

Transmission planning and requests for transmission service and generator interconnection are interrelated to the resource planning process. DEC 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. Generator interconnection requests are studied in accordance with the Large and Small Generator Interconnection Procedures in the OATT.

SERC audits DEC every three years for compliance with NERC Reliability Standards. Specifically, the audit requires DEC to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the Company's annual compliance filing certifications. SERC conducted a NERC Reliability Standards compliance audit of DEC in May 2011. The scope of this audit included Transmission Planning Standards TPL-002-0.a and TPL- 003-0a. For both Standards, DEC received "No Findings" from the audit team.

DEC participates in a number of regional reliability groups to coordinate analysis of regional, sub-regional and inter-balancing authority 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 interconnected system 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.

Application of the practices and procedures described above have ensured DEC's transmission system is expected to continue to provide reliable service to its native load and firm transmission customers.

APPENDIX J: ECONOMIC DEVELOPMENT

Customers Served Under Economic Development

In the NCUC Order issued in Docket No. E-100, Sub 73 dated November 28, 1994, 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. 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) as of June 2013 is:

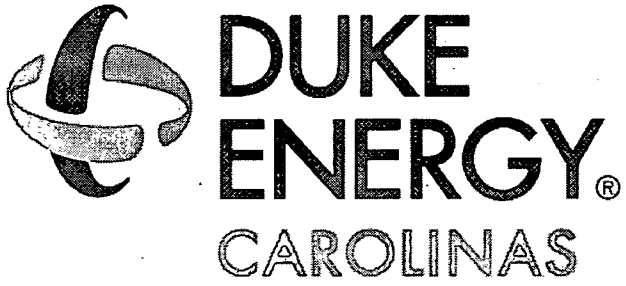
Rider EC:
134 MW for North Carolina
60 MW for South Carolina

Rider ER:
2 MW for North Carolina
0 MW for South Carolina

APPENDIX K: CROSS-REFERENCE OF IRP REQUIREMENTS

The following table cross-references IRP regulatory requirements for NC R8-60 in North Carolina and S.C. Code Ann. § 58-37-10 in South Carolina, and identifies where those requirements are discussed in the IRP.

Requirement	Location	Reference	Updated
15-year Forecast of Load, Capacity and Reserves	Ch 8, Tables 8.C & D	NC R8-60 (c) 1	Yes
Comprehensive analysis of all resource options	Ch 4, 5 & 8, App A	NC R8-60 (c) 2	Yes
Assessment of Purchased Power	Table H.1	NC R8-60 (d)	Yes
Assessment of Alternative Supply-Side Energy Resources	Ch 5, App B & D	NC R8-60 (e)	Yes
Assessment of Demand-Side Management	Ch 4, App D	NC R8-60 (f)	Yes
Evaluation of Resource Options	Ch 8, App A, C & F	NC R8-60 (g)	Yes
Short-Term Action Plan	Ch 9	NC R8-60 (h) 3	Yes
REPS Compliance Plan	Attachment	NC R8-60 (h) 4	Yes
Forecasts of Load, Supply-Side Resources, and Demand-Side Resources			
* 10-year History of Customers and Energy Sales	App C	NC R8-60 (i) 1(i)	Yes
* 15-year Forecast w & w/o Energy Efficiency	Ch 3 & App C	NC R8-60 (i) 1(ii)	Yes
* Description of Supply-Side Resources	Ch 6 & App A	NC R8-60 (i) 1(iii)	Yes
Generating Facilities			
* Existing Generation	Ch 2, App B	NC R8-60 (i) 2(i)	Yes
* Planned Generation	Ch 8 & App A	NC R8-60 (i) 2(ii)	Yes
* Non Utility Generation	Ch 5, App H	NC R8-60 (i) 2(iii)	Yes
Reserve Margins	Ch 7, 8, Table 8.D	NC R8-60 (i) 3	Yes
Wholesale Contracts for the Purchase and Sale of Power			
* Wholesale Purchased Power Contracts	App H	NC R8-60 (i) 4(i)	Yes
* Request for Proposal	Ch 9	NC R8-60 (i) 4(ii)	Yes
* Wholesale Power Sales Contracts	App C & H	NC R8-60 (i) 4(iii)	Yes
Transmission Facilities	Ch 2, 7 & App I	NC R8-60 (i) 5	Yes
Energy Efficiency and Demand-Side Management			
* Existing Programs	Ch 4 & App D	NC R8-60 (i) 6(i)	Yes
* Future Programs	Ch 4 & App D	NC R8-60 (i) 6(ii)	Yes
* Rejected Programs	App D	NC R8-60 (i) 4(iii)	Yes
* Consumer Education Programs	App D	NC R8-60 (i) 4(iv)	Yes
Assessment of Alternative Supply-Side Energy Resources			
* Current and Future Alternative Supply-Side Resources	Ch 5, App F	NC R8-60 (i) 7(i)	Yes
* Rejected Alternative Supply-Side Resources	Ch 5, App F	NC R8-60 (i) 7(ii)	Yes
Evaluation of Resource Options (Quantitative Analysis)	App A	NC R8-60 (i) 8	Yes
Levelized Bus-bar Costs	App F	NC R8-60 (i) 9	Yes
Smart Grid Impacts	App D	NC R8-60 (i) 10	Yes
Legislative and Regulatory Issues	App G		Yes
Greenhouse Gas Reduction Compliance Plan	App G		Yes
Other Information (Economic Development)	App J		Yes



The Duke Energy Carolinas

N.C. Renewable Energy & Energy Efficiency Portfolio Standard (NC REPS) Compliance Plan

October 15, 2013

NC REPS Compliance Plan
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I. INTRODUCTION

Duke Energy Carolinas, LLC (Duke Energy Carolinas or the Company) submits its annual Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS or REPS) Compliance Plan (Compliance Plan) in accordance with N.C. Gen. Stat. § 62-133.8 and North Carolina Utilities Commission (the Commission) Rule R8-67(b). This Compliance Plan, set forth in detail in Section II and Section III, provides the required information and outlines the Company's projected plans to comply with NC REPS for the period 2013 to 2015 (the Planning Period). Section IV addresses the cost implications of the Company's REPS Compliance Plan.

In 2007, the North Carolina General Assembly enacted Session Law 2007-397 (Senate Bill 3), codified in relevant part as N.C. Gen. Stat. § 62-133.8, in order to:

(1) Diversify the resources used to reliably meet the energy needs of consumers in the State;
(2) Provide greater energy security through the use of indigenous energy resources available within the State;
(3) Encourage private investment in renewable energy and energy efficiency; and
(4) Provide improved air quality and other benefits to energy consumers and citizens of the State.

As part of the broad policy initiatives listed above, Senate Bill 3 established the NC REPS, which requires the investor-owned utilities, electric membership corporations or co-operatives, and municipalities to procure or produce renewable energy, or achieve energy efficiency savings, in amounts equivalent to specified percentages of their respective retail megawatt-hour (MWh) sales from the prior calendar year.

Duke Energy Carolinas seeks to advance these State policies and comply with its REPS obligations through a diverse portfolio of cost-effective renewable energy and energy efficiency resources. Specifically, the key components of Duke Energy Carolinas' 2013 Compliance Plan include: (1) introduction of energy efficiency programs that will generate savings that can be counted towards the Company's REPS obligation; (2) purchases of renewable energy certificates (RECs); (3) continued operations of company-owned renewable facilities; and (4) research studies to enhance the Company's ability to comply with its REPS obligations in the future. The Company believes that these actions yield a diverse portfolio of qualifying resources and allow a flexible mechanism for compliance with the requirements of N.C. Gen. Stat. § 62-133.8.

In addition, the Company has undertaken, and will continue to undertake, specific regulatory and operational initiatives to support REPS compliance, including: (1) submission of regulatory applications to pursue reasonable and appropriate renewable energy and energy efficiency initiatives in support of the Company's REPS compliance needs; (2) solicitation, review, and analysis of proposals from renewable energy suppliers offering RECs and diligent pursuit of the most attractive opportunities, as appropriate;

and (3) development and implementation of administrative processes to manage the Company's REPS compliance operations, such as procuring and managing renewable resource contracts, accounting for RECs, safely interconnecting renewable energy suppliers, reporting renewable generation to the North Carolina Renewable Energy Tracking System (NC-RETS), and forecasting renewable resource availability and cost in the future.

The Company believes these actions collectively constitute a thorough and prudent plan for compliance with NC REPS and demonstrate the Company's commitment to pursue its renewable energy and energy efficiency strategies for the benefit of its customers.

II. REPS COMPLIANCE OBLIGATION

Duke Energy Carolinas calculates its NC REPS Compliance Obligations[3] in 2013, 2014, and 2015 based on interpretation of the statute (N.C. Gen. Stat. § 62-133.8), the Commission's rules implementing Senate Bill 3 (Rule R8-67), and subsequent Commission orders, as applied to the Company's actual or forecasted retail sales in the Planning Period, as well as the actual and forecasted retail sales of those wholesale customers for whom the Company is supplying REPS compliance. The Company's wholesale customers for which it supplies REPS compliance services are Rutherford Electric Membership Corporation, Blue Ridge Electric Membership Corporation, City of Dallas, Forest City, City of Concord, Town of Highlands, and the City of Kings Mountain (collectively referred to as Wholesale or Wholesale Customers)[4]. Table 1 below shows the Company's retail and Wholesale customers' REPS Compliance Obligation.

[3] For the purposes of this Compliance Plan, Compliance Obligation is more specifically defined as the sum of Duke Energy Carolinas' native load obligations for both the Company's retail sales and for wholesale native load priority customers' retail sales for whom the Company is supplying REPS compliance. All references to the respective Set-Aside requirements, the General Requirements, and REPS Compliance Obligation of the Company include the aggregate obligations of both Duke Energy Carolinas and the Wholesale Customers. Also, for purposes of this Compliance Plan, all references to the compliance activities and plans of the Company shall encompass such activities and plans being undertaken by Duke Energy Carolinas on behalf of the Wholesale Customers.

[4] For purposes of this Compliance Plan, Retail Sales is defined as the sum of Duke Energy Carolinas retail sales and the retail sales of the wholesale customers for whom the company is supplying REPS compliance.

Table 1: Duke Energy Carolinas' NC REPS Compliance Obligation

Compliance Year	Previous Year DEC Retail Sales (MWh)	Previous Year Wholesale Retail Sales (MWhs)	Total Retail Sales for REPS Compliance (MWhs)	Solar Set-Aside (RECs)	Swine Set-Aside (RECs)	Poultry Set-Aside (RECs)	REPS Requirement (%)	Total REPS Compliance Obligation (RECs)
2013	54,555,907	4,006,605	58,562,512	40,994	40,994	75,678	3%	1,756,875
2014	55,232,870	3,928,975	59,161,845	41,413	41,413	313,682	3%	1,774,855
2015	55,756,164	3,987,615	59,743,779	83,641	83,641	405,824	6%	3,584,627

Note: Obligation is determined by prior-year MWh sales. Thus, retail sales figures for compliance years 2014 and 2015 are estimates.

As shown in Table 1, the Company's requirements in the Planning Period include the solar energy resource requirement (Solar Set-Aside), swine waste resource requirement (Swine Set-Aside), and poultry waste resource requirement (Poultry Set-Aside). In addition, the Company must also ensure that, in total, the RECs that it produces or procures, combined with energy efficiency savings, is an amount equivalent to 3% of its prior year retail sales in compliance years 2013 and 2014, and 6% of its prior year retail sales in compliance year 2015. The Company refers to this as its Total Obligation. For clarification, the Company refers to its Total Obligation, net of the Solar, Swine, and Poultry Set-Aside requirements, as its General Requirement.

III. REPS COMPLIANCE PLAN

In accordance with Commission Rule R8-67b(1)(i), the Company describes its planned actions to comply with the Solar, Swine, and Poultry Set-Asides, as well as the General Requirement below. The discussion first addresses the Company's efforts to meet the Set-Aside requirements and then outlines the Company's efforts to meet its General Requirement in the Planning Period.

A. SOLAR ENERGY RESOURCES

Pursuant to N.C. Gen. Stat. § 62-133.8(d), the Company must produce or procure solar RECs equal to a minimum of 0.07% of the prior year total electric energy in megawatt-hours (MWh) sold to retail customers in North Carolina in 2013 and 2014, rising to a minimum of 0.14% in 2015.

Based on the Company's actual retail sales in 2012, the Solar Set-Aside is approximately 40,994 RECs in 2013. Based on forecasted retail sales, the Solar Set-Aside is projected to be approximately 41,413 RECs and 86,641 RECs in 2014 and 2015, respectively.

The Company's plan for meeting the Solar Set-Aside in the Planning Period is consistent with its plan from the previous year, as described in further detail below.

1. Solar Photovoltaic Distributed Generation (PVDG) Program

The Duke Energy PVDG Program, approved by the Commission in 2009[5], refers to solar installations across multiple sites, totaling approximately ten (10) megawatts (DC) of installed capacity. The Company continues to operate these facilities in support of our REPS compliance obligations, and the facilities remain an integral part of the Company's renewable portfolio.

2. Solar PPAs and Solar REC Purchase Agreements

Duke Energy Carolinas has executed multiple solar REC purchase agreements with third parties for the purchase of solar RECs. These agreements include contracts with multiple in-state and out-of-state counterparties to procure solar RECs from both photovoltaic (PV) and solar water heating installations. Additional details with respect to the REC purchase agreements are set forth in Exhibit A.

3. Review of Company's Solar Set-Aside Plan

The Company has made and continues to make reasonable efforts to meet the Solar Set-Aside requirement in the Planning Period, and remains confident that it will be able to comply with this requirement. Therefore, the Company sees minimal risk in meeting the Solar Set-Aside and will continue to monitor the development and progress of solar initiatives and take appropriate actions as necessary.

B. SWINE WASTE-TO-ENERGY RESOURCES

Pursuant to N.C. Gen. Stat. § 62-133.8(e), for calendar years 2013 and 2014, at least 0.07% of prior year total retail electric energy sold in aggregate by utilities in North Carolina must be supplied by energy derived from swine waste. In 2015, at least 0.14% of prior year total retail electric energy sold in aggregate by utilities in North Carolina must be supplied by energy derived from swine waste. The Company's Swine Set-Aside is estimated to be 40,994 RECs in 2013, 41,413 RECs in 2014, and 83,641 RECs in 2015.

In spite of Duke Energy Carolinas' active and diligent efforts to secure resources to comply with its Swine Set-Aside requirements, the Company has been unable to secure sufficient volumes of RECs to meet its pro-rata share of the swine set-aside requirements in 2013. The Company remains actively engaged in seeking additional resources and continues to make every reasonable effort to comply with the swine waste set-aside requirements. The Company's ability to comply in 2014 and 2015 remains highly uncertain and subject to multiple variables, particularly relating to counterparty achievement of projected delivery requirements and commercial operation milestones. Additional details with respect to

[5] See *Order Granting Certificate of Public Convenience and Necessity Subject to Conditions*, Docket No. E-7, Sub 856 (May 2009).

the Company's compliance efforts and REC purchase agreements are set forth in Exhibit A and the Company's tri-annual progress reports, filed confidentially in Docket E-100 Sub113A.

Due to its expected non-compliance in 2013, the Company will submit a motion to the Commission for approval of a request to relieve the Company from compliance with the swine-waste requirements until calendar year 2014 by delaying the compliance obligation for a one year period.

C. POULTRY WASTE-TO-ENERGY RESOURCES

Pursuant to N.C. Gen. Stat. § 62-133.8(f) and as amended by NCUC *Order on Pro Rata Allocation of Aggregate Swine and Poultry Waste Requirements and Motion for Clarification* in Docket E-100, Sub113, for calendar years 2013, 2014, and 2015, at least 170,000 MWh, 700,000 MWh, and 900,000 MWh, respectively, of the prior year total electric energy sold to retail electric customers in the State or an equivalent amount of energy shall be produced or procured each year from poultry waste, as defined per the Statute and additional clarifying Orders. As the Company's retail sales share of the State's total retail megawatt-hour sales is approximately 45%, the Company's Poultry Set-Aside is estimated to be 75,678 RECs in 2013, 313,682 RECs in 2014, and 405,824 in 2015.

In spite of Duke Energy Carolinas' active and diligent efforts to secure resources to comply with its Poultry Set-Aside requirements, the Company has been unable to secure sufficient volumes of RECs to meet its pro-rata share of the poultry set-aside requirements in 2013 and 2014. The Company remains actively engaged in seeking additional resources and continues to make every reasonable effort to comply with the poultry waste set-aside requirements. The Company's ability to comply in 2015 remains highly uncertain and subject to multiple variables, particularly relating to counterparty achievement of projected delivery requirements and commercial operation milestones. Additional details with respect to the Company's compliance efforts and REC purchase agreements are set forth in Exhibit A and the Company's tri-annual progress reports, filed confidentially in Docket E-100 Sub113A.

Due to its expected non-compliance in 2013, the Company will submit a motion to the Commission for approval of a request to relieve the Company from compliance with the poultry-waste requirements until calendar year 2014 by delaying the compliance obligation for a one year period.

D. GENERAL REQUIREMENT RESOURCES

Pursuant to N.C. Gen. Stat. § 62-133.8, Duke Energy Carolinas is required to comply with its Total Obligation in 2013 and 2014 by submitting for retirement a total volume of RECs equivalent to 3% of retail sales in North Carolina in the prior year, rising to 6% of retail sales in 2015: approximately 1,756,875 RECs in 2013, 1,774,855 RECs in 2014, and 3,584,627 RECs in 2015. This requirement, net of the Solar, Swine, and Poultry Set-Aside requirements, is estimated to be 1,599,213 RECs in 2013,

1,378,364 RECs in 2014, and 3,011,555 in 2015.[6] The various resource options available to the Company to meet the General Requirement are discussed below, as well as the Company's plan to meet the General Requirement with these resources.

1. Energy Efficiency

During the Planning Period, the Company plans to meet 25% of the Total Obligation EE savings, which is the maximum allowable amount under N.C. Gen. Stat. § 62-133.7(b)(2)c. This will be accomplished by utilizing EE savings from the Company's Commission-approved programs which began in 2009. Because the Company's first General Requirement began in 2012, EE savings was banked during the years 2009-2011 for future use. The Company will also continue to develop and offer its customers new and innovative EE programs in the future that will deliver savings and count towards its future NC REPS requirements.

Please refer to Appendix D, for descriptions of the Company's Energy Efficiency programs.

Pursuant to Commission Rule R8-67b(1)(iii), the Company has attached a list of those EE measures that it plans to use toward REPS compliance, including projected impacts, as Exhibit B.

2. Hydroelectric Power

Duke Energy Carolinas plans to use hydroelectric power from three sources to meet the General Requirement in the Planning Period: (1) Duke-owned hydroelectric stations that are approved as renewable energy facilities; (2) Wholesale Customers' Southeastern Power Administration (SEPA) allocations; and (3) hydroelectric generation suppliers whose facilities have received Qualifying Facility (QF or QF Hydro) status. The Company has received Commission approval for ten of its hydroelectric stations as renewable energy facilities. The Company continues to evaluate the use of the RECs generated by these facilities to meet the General Requirements of Duke Energy Carolinas' Wholesale Customers, pursuant to N.C. Gen. Stat. § 62-133.8(c)(2)c and 62-33.8(c)(2)d. Wholesale Customers may also bank and utilize hydroelectric resources arising from their full allocations of SEPA. When supplying compliance for the Wholesale Customers, the Company will ensure that hydroelectric resources do not comprise more than 30% of each Wholesale Customers' respective compliance portfolio, pursuant to N.C. Gen. Stat. § 62-133.8(c)(2)c. In 2012, the Company also received Commission approval for a new, incremental capacity addition at another of its hydrofacilities, Bridgewater. The Company intends to apply RECs generated by this facility toward the General Requirements of Duke Energy Carolinas' retail customers. In addition, the Company is purchasing RECs from multiple QF Hydro facilities in the Carolinas and will use RECs from these facilities toward

[6] If the Commission grants relief from the 2013 swine-waste and poultry-waste obligations, the Company's Total Obligation would not changed but its General Requirement would increase as the Swine and Poultry Set Asides would not be netted against the Total Obligation in compliance year 2013.

General Requirements of Duke Energy Carolinas' retail customers. Please see Exhibit A for more information on each of these contracts.

3. Biomass Resources

Duke Energy Carolinas plans to meet a portion of the General Requirement through a variety of biomass resources, including landfill gas to energy, combined-heat and power, and direct combustion of biomass fuels. The Company is purchasing RECs from multiple biomass facilities in the Carolinas, including landfill gas to energy facilities and biomass-fueled combined heat and power facilities, all of which qualify as renewable energy facilities. Please see Exhibit A for more information on each of these contracts.

Duke Energy Carolinas notes, however, that reliance on direct-combustion biomass has decreased in long-term planning horizons. This reduction is in part due to continued uncertainties around the developable potential of such resources in the Carolinas and the projected availability of other forms of renewable resources to offset the need for biomass.

4. Wind

Duke Energy Carolinas plans to meet a portion of the General Requirement with RECs from wind facilities. As discussed in the Company's 2013 IRP, the Company believes it is reasonable to expect that land-based wind will be developed in both North and South Carolina in the next decade. However, in the short-term, extension of the federal tax subsidy available to new wind generation facilities remains uncertain. While the company expects to rely upon wind resources for our REPS compliance effort, the extent and timing of that reliance will likely vary commensurately with changes to supporting policies and prevailing market prices. The Company also has observed that opportunities may 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.

5. Use of Solar Resources for General Requirement

Duke Energy Carolinas plans to meet a portion of the General Requirement with RECs from solar facilities. As discussed in the Company's 2013 IRP, the Company views the downward trend in solar equipment and installation costs over the past several years as a positive development. Additionally, new solar facilities also benefit from generous supportive federal and state policies that are expected to be in place through the middle of this decade. While uncertainty remains around possible alterations or extensions of policy support, as well as the pace of future cost declines, the Company fully expects solar resources to contribute to our compliance efforts beyond the solar set-aside minimum threshold for NC REPS during the Planning Period.

6. Review of Company's General Requirement Plan

The Company has contracted for or otherwise procured sufficient resources to meet its General Requirement in the Planning Period. Based on the known information available at the time of this filing, the Company is confident that it will meet this General Requirement during the Planning Period and submits that the actions and plans described herein represent a reasonable and prudent plan for meeting the General Requirement.

E. SUMMARY OF RENEWABLE RESOURCES

The Company has evaluated, procured, and/or developed a variety of types of renewable and energy efficiency resources to meet its NC REPS requirements within the compliance Planning Period. As noted above, several risks and uncertainties exist across the various types of resources and the associated parameters of the NC REPS requirements. The Company continues to carefully monitor opportunities and unexpected developments across all facets of its compliance requirements. Duke Energy Carolinas submits that it has crafted a prudent, reasonable plan with a diversified balance of renewable resources that will allow the Company to comply with its NC REPS obligation over the Planning Period.

IV. COST IMPLICATIONS OF REPS COMPLIANCE PLAN

A. CURRENT AND PROJECTED AVOIDED COST RATES

The current avoided cost rates represent the annualized avoided cost rates in Schedule PP-N (NC), Distribution Interconnection, approved in the Commission's *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, issued in Docket No. E-100, Sub 127 (July 27, 2011). The projected avoided cost rates represent the annualized avoided cost rates proposed by the Company in Docket No. E-100, Sub 136.

Table 2: Annualized Capacity and Energy Rates (cents per kWh)

	2013 (Current)	2014 (Projected)	2015 (Projected)
Variable Rate	5.48¢	4.94¢	4.94¢
5 Year	5.63¢	5.15¢	5.15¢
10 Year	6.28¢	5.48¢	5.48¢
15 Year	6.63¢	5.80¢	5.80¢

B. PROJECTED TOTAL NORTH CAROLINA RETAIL AND WHOLESALE SALES AND YEAR-END NUMBER OF CUSTOMER ACCOUNTS BY CLASS

The tables below reflect the inclusion of the Wholesale Customers in the Compliance Plan.

Table 3: Retail Sales for Retail and Wholesale Customers

	2012 (Actuals)	2013	2014
Retail MWh Sales	54,555,907	55,232,870	55,756,164
Wholesale MWh Sales	4,006,605	3,928,975	3,987,615
Total MWh Sales	58,562,512	59,161,845	59,743,779

Note: The MWh sales reported above are those applicable to REPS compliance years 2013 – 2015, and represent actual MWh sales for 2012, and projected MWh sales for 2013 and 2014, respectively.

Table 4: Retail and Wholesale Year-end Number of Customer Accounts

	2012 (Actuals)	2013	2014	2015
Residential Accts	1,625,359	1,634,116	1,647,527	1,666,206
General Accts	253,030	258,407	262,960	267,090
Industrial Accts	5,069	5,254	5,263	5,256

Note: The number of accounts reported above are those applicable to the cost caps for compliance years 2013 – 2015, and represent the actual number of accounts for year-end 2012, and the projected number of accounts for year-end 2013 through 2015.

C. PROJECTED ANNUAL COST CAP COMPARISON OF TOTAL AND INCREMENTAL COSTS, REPS RIDER AND FUEL COST IMPACT

Projected compliance costs for the Planning Period are presented in the cost tables below by calendar year. The cost cap data is based on the number of accounts as reported above.

Table 5: Projected Annual Cost Caps and Fuel Related Cost Impact

	2013	2014	2015
Total projected REPS compliance costs	$ 32,969,472	$ 46,126,516	$ 50,567,253
Recovered through the Fuel Rider	$ 24,690,757	$ 33,996,739	$ 35,985,121
Total incremental costs (REPS Rider)	$ 8,278,714	$ 12,129,777	$ 14,582,132
Total Including GRT and Regulatory Fee	$ 8,575,016	$ 12,563,910	$ 15,104,036
Projected Annual Cost Caps (REPS Rider)	$ 63,600,083	$ 64,543,124	$ 106,425,364

EXHIBIT A

Duke Energy Carolinas, LLC's 2013 REPS Compliance Plan
Duke Energy Carolinas' Renewable Resource Procurement from 3rd Parties
(signed contracts)

[BEGIN CONFIDENTIAL]

Resource Supplier	Contract Duration	Estimated RECs		
		2013	2014	2015
Solar Resources				
	5 years *			
	20 Years *			
	10 Years			
	5 Years			
	5 Years *			
	5 Years			
	5 Years *			
	15 Years			
	20 Years *			
	15 Years *			
	20 Years *			
Total Solar REC Purchases				

Resource Supplier	Contract Duration	Estimated RECs		
		2013	2014	2015
Biomass Resources				
	20 Years*			
	20 Years*			
	20 Years*			
	20 Years*			
	10 Years*			
	20 Years*			
	10 Years*			
	10 Years*			
	9 Years*			
	20 Years*			
	15 Years*			
	15 Years*			
	15 Years*			
Total Biomass REC Purchases				
Poultry Waste to Energy Resources				
	10 Years			
	20 Years*			
Total Poultry REC Purchases				
Swine Waste to Energy Resources				
	10 Years			
	10 Years			
	20 Years			
	20 Years			
	20 Years			
	20 Years			
Total Swine REC Purchases				

Resource Supplier	Contract Duration	Estimated RECs		
		2013	2014	2015
Hydro Electric Resources				
		2013	2014	2015
[redacted]	5 years*	[redacted]		
	5 Years*			
	5 Years*			
	5 Years*			
	5 Years*			
	5 Years*			
	5 Years*			
	5 Years*			
	5 Years*			
	8 Years*			
	8 Years*			
	8 Years*			
	8 Years*			
	5 Years*			
	5 Years*			
	5 Years*			
	5 Years*			
	5 years*			
Total Hydro Purchases				

* Indicates bundle purchase of RECs and energy, as opposed to REC-only purchase.

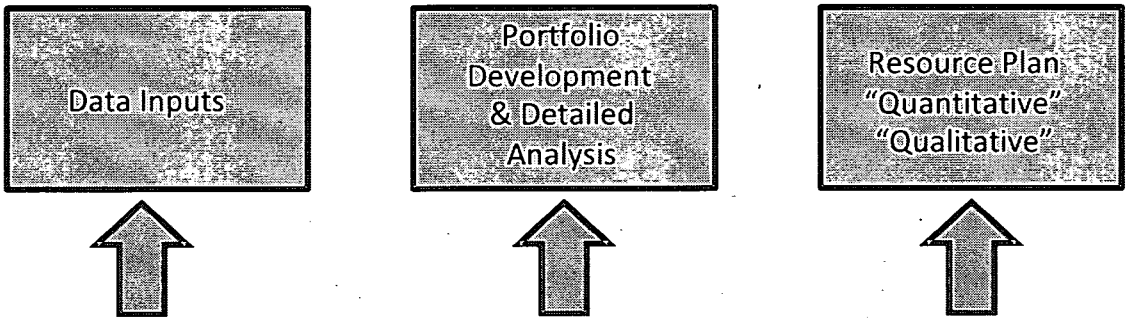
[END CONFIDENTIAL]

EXHIBIT B

Duke Energy Carolinas, LLC's 2013 REPS Compliance Plan
Duke Energy Carolinas, LLC's EE Programs and Projected REPS Impacts

Forecasted Annual Energy Efficiency Impacts for the REPS Compliance Planning Period 2013, 2014, 2015 (MWh)			
	2013	2014	2015
Residential Programs			
Residential Energy Assessments	4,935	4,116	4,116
Smart Saver® for Residential Customers	48,562	37,080	39,667
Low Income Energy Efficiency and Weatherization Assistance	1,842	1,842	1,832
Energy Efficiency Education Program for Schools	5,318	5,297	5,297
Appliance Recycle	30,429	34,868	34,868
Residential Neighborhood Low Income Program	8,454	7,655	7,017
My Home Energy Report	101,110	1,508	3,061
Sub Total	200,650	92,366	95,858
Non Residential Programs			
Smart Saver® for Non-Res Customers	213,697	223,834	235,026
Sub Total	213,697	223,834	235,026
Total	414,346	316,200	330,885

Exhibit Hager - 2
IRP Process



- Load Forecast
- Fuel Price Forecasts
- Existing Generation
- Energy Efficiency
- Demand Response
- Renewable Resources
- New Generation
- Environmental Legislation

- Generation Alternative Screening
- Expansion Plan Modeling
- Minimization of Revenue Requirements

- Fuel Diversity
- Environmental Footprint
- Flexibility
- Rate Impact

Exhibit Hager - 3
Total Retail Load without EE

Load Forecast without Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWh)
2014	18,443	17,718	93,566
2015	18,875	18,132	95,762
2016	19,328	18,553	98,023
2017	19,780	18,961	100,356
2018	20,231	19,376	102,773
2019	20,717	19,789	105,027
2020	21,067	20,143	106,904
2021	21,417	20,495	108,749
2022	21,776	20,842	110,634
2023	22,143	21,195	112,522
2024	22,525	21,563	114,471
2025	22,901	21,925	116,405
2026	23,280	22,299	118,371
2027	23,655	22,660	120,327
2028	24,017	23,015	122,243

Exhibit Hager – 3
Total Retail Load with EE

Load Forecast with Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWh)
2014	18,332	17,654	92,943
2015	18,691	18,009	94,721
2016	19,053	18,359	96,475
2017	19,398	18,685	98,226
2018	19,741	18,979	100,032
2019	20,117	19,304	101,678
2020	20,359	19,571	102,948
2021	20,598	19,834	104,187
2022	20,848	20,093	105,469
2023	21,104	20,359	106,748
2024	21,378	20,640	108,089
2025	21,643	20,913	109,418
2026	21,922	21,206	110,825
2027	22,209	21,496	112,294
2028	22,496	21,790	113,769

Exhibit Hager - 4

2014 Capacity by Fuel Type

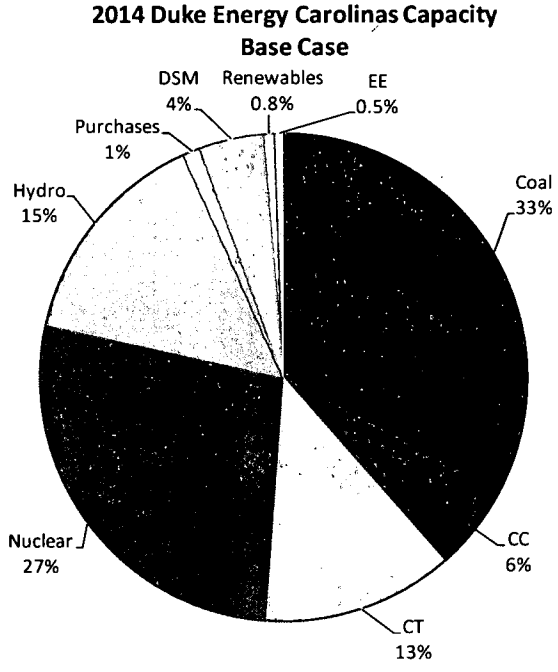


Exhibit Hager - 5

Joint Planning Scenario

Duke Energy Carolinas and Duke Energy Progress Base Case Combined Resource Plans		
Year	**Resource**	**MW**
2014	-	-
2015	-	-
2016	-	-
2017	New CC	680
2018	Fast Start CT / VC Summer Nuclear	126 / 66 / 46
2019	New CC / New CC	843 / 843
2020	VC Summer Nuclear	66 / 46
2021	New CC	843
2022	New CC / New CT	843 / 403
2023	-	-
2024	New Nuclear	1117
2025	-	-
2026	New Nuclear	1117
2027	New CT	403
2028	-	-

Delays 1 year

Delays 2 years & Need changes to CT

Delays 1 year

Duke Energy Carolinas and Duke Energy Progress Joint Planning Scenario Resource Plan		
Year	**Resource**	**MW**
2014	-	-
2015	-	-
2016	-	-
2017	-	-
2018	Fast Start CT / New CC / VC Summer Nuclear	126 / 680 / 66 / 46
2019	New CC	843
2020	VC Summer Nuclear	66 / 46
2021	New CC / New CT	843 / 403
2022	New CC	843
2023	New CT	403
2024	New Nuclear	659 / 458
2025	-	-
2026	New Nuclear	659 / 458
2027	-	-
2028	-	-

Outside Study Period

Exhibit Hager - 6

RFP Refreshed Bid Analysis Results

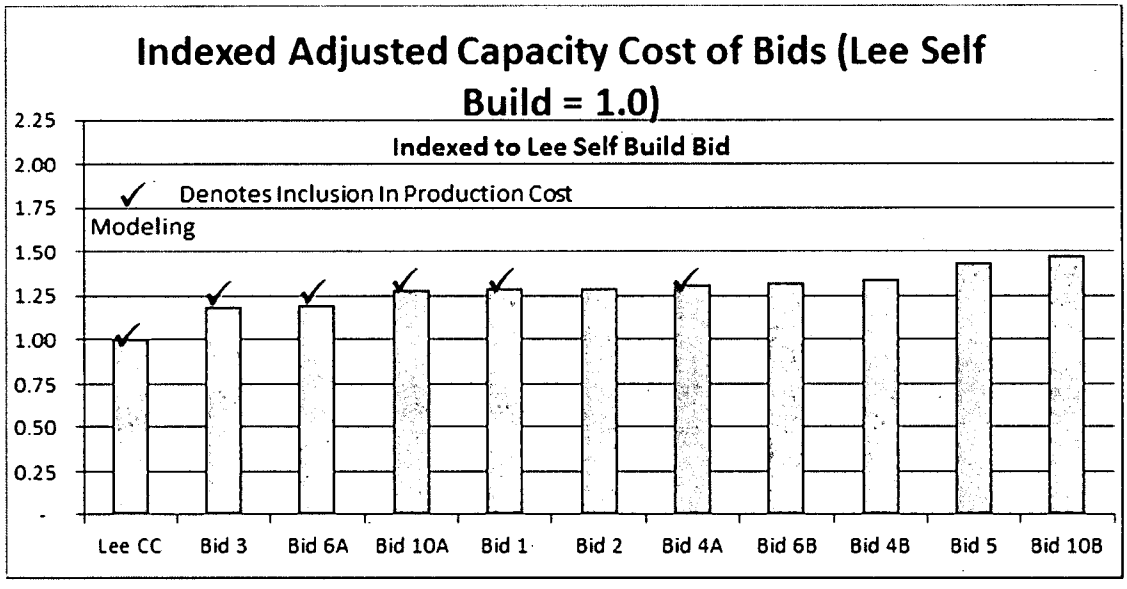
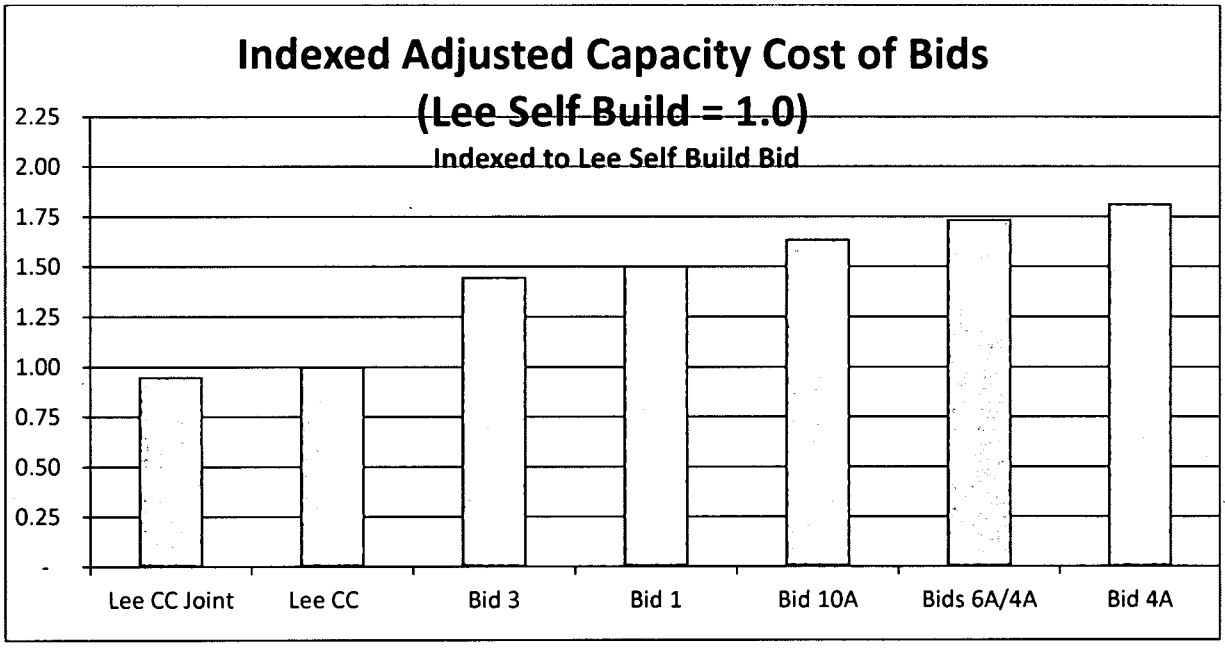


Exhibit Hager - 7

RFP Phase 2 Analysis Results



Scope of Services for Duke Energy Carolinas Power Supply RFP

Engineer shall work collaboratively with Client to:

1. Review the Scope of the RFP

2. Review RFP Product Specifications

3. Duke will provide an email distribution list of RFP recipients

4. Create and manage a specific web site for the RFP
   - The web site will enable potential bidders to download the RFP and Exhibits, email questions to the Engineer, provide useful links to other web sites and view questions and answers from other potential bidders. This task is to also include the creation of a private email address for access only by the Engineer for use in all communications between the Engineer and potential bidders.

5. Manage the entire RFP process to meet the Edgar Standards described in FERC Docket No. ER05-121-000
   - The Engineer shall independently manage the RFP.
   - The Engineer shall receive the Notices Of Intent to Bid and notify the Client of the number of potential responders.
   - The Engineer shall distribute the RFP
   - The Engineer shall assist Duke as an initial point of contact for questions regarding the RFP.
   - The Engineer shall draft responses to RFP questions for Client's review and approval. Duke affiliates will not be permitted to bid in this RFP.

6. Receive the RFP Responses and open the proposals in private
   - Upon receipt of the various responses, the Engineer will provide proposals to the Client for evaluation by the Client.
   - Engineer to forward copies of bid proposal packages to the Client immediately as received. .

7. Evaluate the RFP
   - The Engineer will provide assistance to Client through the evaluation process by obtaining further information if needed from the bidders.
   - The Engineer will meet/conference (as needed) with the Client and review the Client's assumptions, inputs, internal bid and models and then the evaluation and short list of bidders.
   - The Engineer will participate in conference calls or meetings with short list bidders to ensure all bidders are treated fairly.
   - The Engineer's report on the evaluation process shall be developed independently

8. The Engineer shall provide notifications to the short list and losing bidders.

Optional Scope of Services for Duke Energy Carolinas Project- Power Supply RFP (at additional cost)

9. Selection of Winning Bidders
   - The Engineer shall assist Client as requested in the negotiations of the winning bids if needed.

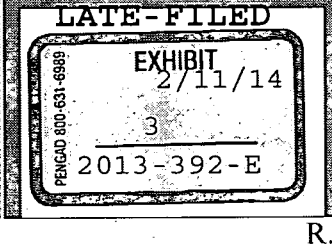
10. Execution of Contracts with Winning Bidder(s)
   - The Engineer is not expected to have a role in this process, but will be available if requested.

11. Defense of Process
   - The Engineer shall be expected to provide testimony before the applicable regulatory bodies, if necessary, both during and beyond the term of this agreement.

Late Filed Exhibit 3

2012

Duke Energy Carolinas 2012 Generation Reserve Margin Study



Astrape Consulting
8/17/2012

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Executive Summary

The reserve margin study performed by Astrape Consulting was requested by Duke Energy Carolinas in response to North Carolina Utilities Commission Order dated October 26, 2011 in Docket No. E -100, Sub 128. The Order requires DEC to perform a comprehensive reserve margin study and include it as part of its 2012 biennial IRP report.

The optimal planning reserve margin for Duke Energy is based on providing an acceptable level of physical reliability and minimizing economic costs to customers. Customers generally expect power to be available 24 hours a day, 365 days a year, but it is economically unreasonable for a load serving entity to maintain enough reserves to meet this expectation. From a physical reliability perspective, Loss of Load Expectation (LOLE) decreases as reserve margin increases. The most common physical metric used in the industry is to target a system reserve margin that meets the one day in 10 year standard which is interpreted as one firm load shed event every 10 years (LOLE = 0.1). A firm load shed event occurs when load plus spinning reserves is greater than available capacity and all options including market purchases and demand response have been exhausted. This results in unserved energy for a firm customer. From an economic perspective, as planning reserve margin increases, the total cost of reserves increases while the costs related to reliability events decline. The economic optimum is defined as the point where the cost of additional reserves plus the cost of reliability events on customers is minimized. For this study, reserve margin is defined as the following:

- Reserve Margin = (Resources – Demand) / Demand
  - Demand is the Average Summer System Peak Load and has not been reduced by Demand Response
  - Resources are defined based on summer ratings and include Demand Response
  - The solar capacity within the study was given a 50% capacity credit while wind was given a 15% capacity credit (consistent with the 2011 IRP)

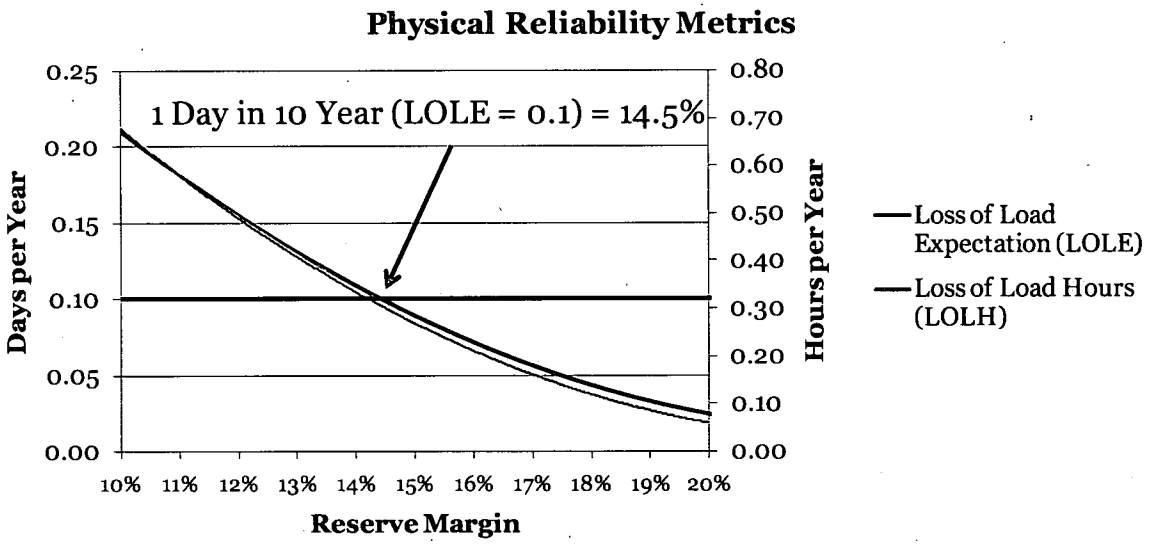
Astrape Consulting has taken a stochastic approach in modeling the uncertainty of weather, economic load growth, unit availability, hydro availability, and transmission availability for emergency tie assistance. Utilizing a multi-area reliability model called SERVM (Strategic Energy and Risk Valuation Model), over 1 million yearly simulations were performed at various reserve margins to calculate the physical reliability metrics and corresponding expected reliability costs. The physical metrics and reliability costs were used to determine an optimal planning reserve margin.

From an economic perspective, the study defines the capacity costs as the annual carrying costs associated with the marginal resource which for this study is a new natural gas combustion turbine. The study defines reliability energy costs as any energy costs the system experiences above the dispatch cost of the marginal resource. These costs include the dispatch of expensive peaking resources such as oil CTs, net imports of expensive market purchases during capacity shortages, and the societal cost of unserved energy.

Summary of Results and Key Insights

The reserve margin that results in 1 day in 10 year LOLE (0.1 days per year) is 14.5% as shown in Figure ES1. Loss of load hours (LOLH) approaches 0.30 hours per year at the 14.5% reserve margin.

Figure ES1. Physical Reliability Metrics



In resource adequacy simulations, firm load shed events are sensitive to inputs due to their infrequent nature. Weather diversity, transmission availability, neighbor reserve levels, and emergency hydro assumptions can shift the 0.1 LOLE reserve margin by several percentage points as shown in the sensitivity section of the report. As an example, emergency hydro assumptions impacted Duke's system LOLE substantially. If the portion of the 1,100 MW hydro capacity that is designated as emergency capacity is available to be used a few hours a month, then the target LOLE reserve margin shifts from 14.50% to 11.25%. This emergency designated block varies by year and month, but during drought conditions, it represents 700-750 MW of unavailable capacity as seen in 2007 and 2008. From a planning perspective, it is difficult to assess the availability of this capacity during drought conditions, and given experience in recent drought years such as 2007 and 2008, it is not prudent to expect this capacity to be available during peak conditions. However, by approaching resource adequacy planning from a more holistic perspective, the target reserve margin is not as sensitive to individual inputs. For this reason, we recommend assessing the economics in addition to the physical reliability metrics. This allows planners

to not only assess the comprehensive benefits of incremental capacity, it also allows for better calibration of physical reliability metrics.

The economic reliability assessment which balances the costs and benefits of incremental capacity is seen in Figure ES2 which demonstrates that the long-term minimum cost reserve margin is 14%. As reserve margin increases, the CT carrying costs rise and the reliability energy costs made up of production costs above a CT, net imports above a CT, and expected unserved energy decrease. Between 14% and 16%, the flatness of the curve indicates that there is not a significant cost impact to being slightly above the minimum cost point. Since resource additions are too large to perfectly target a reserve margin, some years will inevitably result in reserve margins that are higher than the average economic optimum. The expected financial impact of these additions is not substantial, since the capacity above the weighted average target also brings some financial benefit. For example, the annual expected difference in cost between the 14% reserve margin and 16% reserve margin is only $9 million and can provide substantial risk benefit.

Figure ES2. Minimum Weighted Average Cost Reserve Margin

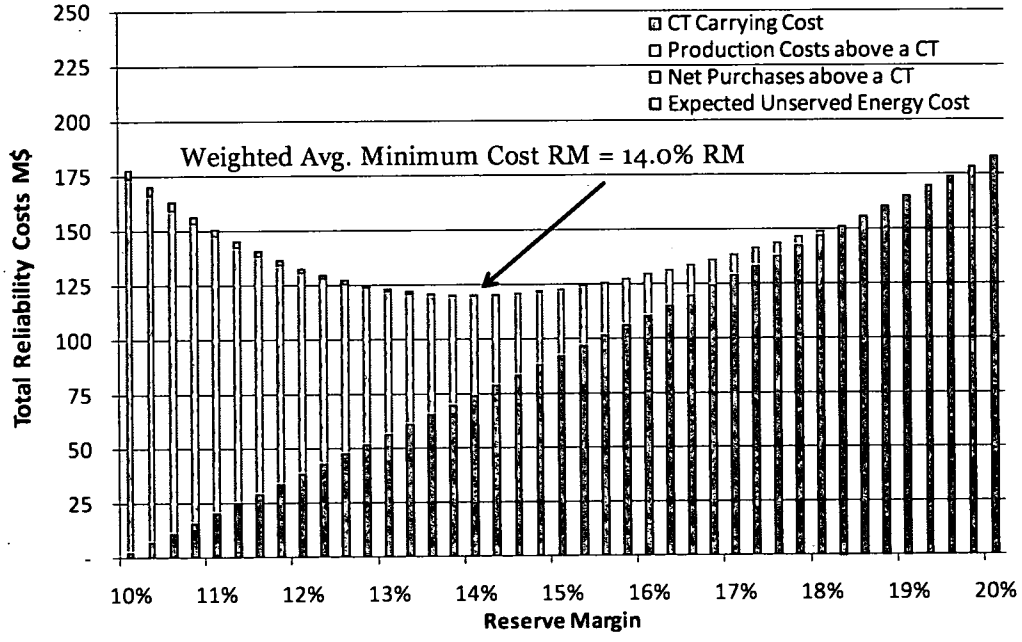
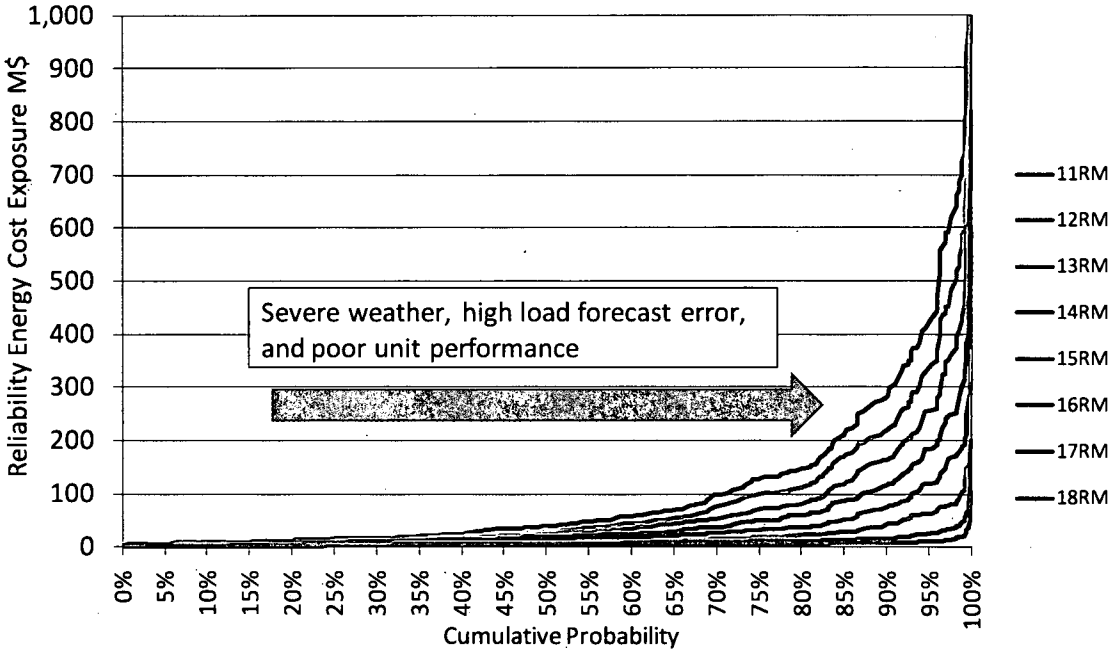


Figure ES3 demonstrates the distribution of reliability energy costs seen in Figure ES2 at each reserve margin level. It should be noted that even at the economic optimum reserve margin of 14% there is still potential for high reliability cost years due to abnormal weather, economic growth, or poor unit performance in the region as shown in the following figure. At a 14% reserve margin, there is a 5% chance that reliability energy costs could exceed $185 million in any given year and a 1% chance that it could exceed $303 million.

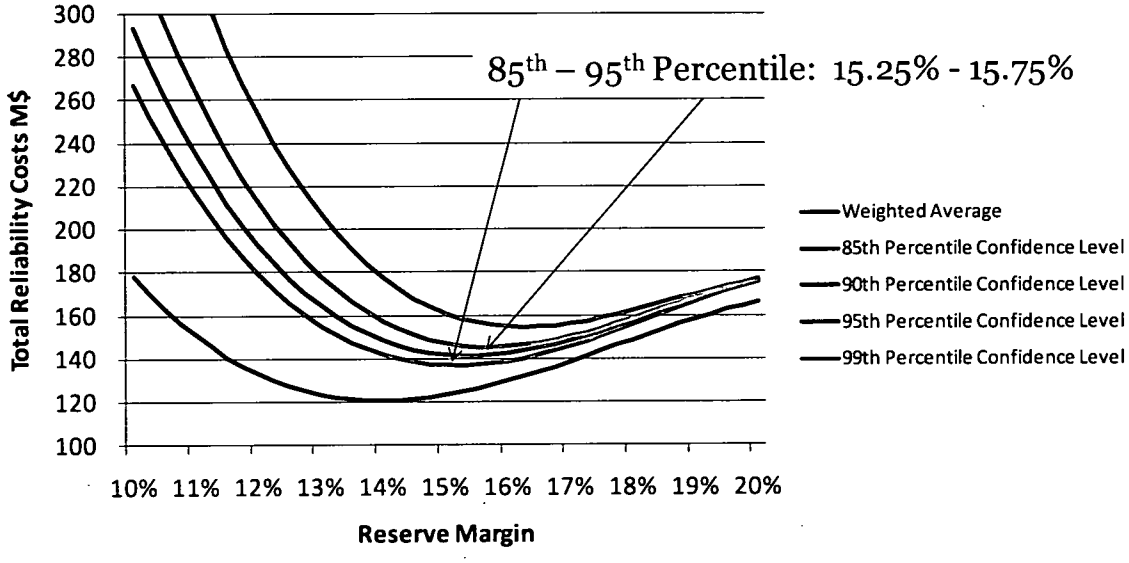
Figure ES3. Distribution of Reliability Energy Costs



Next we examined the optimal economic reserve margin recognizing the different risk profile of energy costs and capacity costs. By comparing capacity costs to reliability energy costs during years with extreme weather or poor unit performance as seen in Figure ES3, we assessed the tail benefit of additional capacity. The reliability energy costs seen in Figure ES3 were taken at different confidence levels (85%, 90%, 95%, and 99% probabilities) and added to the fixed capacity costs at each reserve margin to form the confidence level curves in Figure ES4. This assessment showed that in 10% of all scenarios, Duke

Energy would receive an economic benefit by adding efficient natural gas turbines up to a reserve margin of 15.50%. This is shown by the 90% confidence level curve in Figure ES4. As stated previously, when we review the weighted average curve in the same figure we can see that by adding capacity to achieve a 16% reserve margin versus a 14% reserve margin, average annual costs only increase by $9 million, but the additional capacity acts as an insurance product to customers. In fact, 10% of the time customers would see their cost exposure decrease by at least $70 million in any given year as seen in Figure ES3.

Figure ES4. Optimal Reserve Margins over a Range of Confidence Intervals



Recommendation

Astrape recommends that Duke set its absolute minimum reserve margin at the 14.5% LOLE target (LOLE = 0.1) and recommends a target of 15.50% based on the 90% confidence level economic target. Since capacity is added in large blocks to take advantage of economies of scale, the actual reserve margin will often be somewhat higher than the target threshold of 15.5%. As shown in the charts and data above, a reserve margin target in the range of 14.5% to 16% produces similar total customer costs whether at the low end or high end of the range. To accommodate large resource additions such as

nuclear, coal, or even larger combined cycle resources, the reserve margin would likely rise above the top end of the reserve margin range. However, the additional production cost and economy of scale benefits provided by such resources would likely justify their addition. Therefore, the recommended target reserve margin of 15.50% with a range of 14.5% to 16% should not be considered absolute as all resource decisions should be made on a case-by-case basis.

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III. Input Assumptions

A. Study Year

The selected study year is 2016. The year 2016 was chosen because it is three to four years into the future which is indicative of the amount of time needed to permit and construct a new generating facility. By looking three to four years out, this study reflects a longer term optimal reserve margin. Lower economic load forecast error as well as surrounding market conditions could potentially allow the company to carry slightly lower reserves in the short term.

Although 2016 was selected for the base case simulations, the SERVM simulation results should apply for the 3 to 5 year period following 2016 assuming that resource mixes and market structures do not change drastically over that term. To that end, several sensitivities were run to reflect changes in the market that could occur in this time period as well as a look at a 2023 Study Year.

B. Load Modeling

Table 1. 2016 Load Forecast

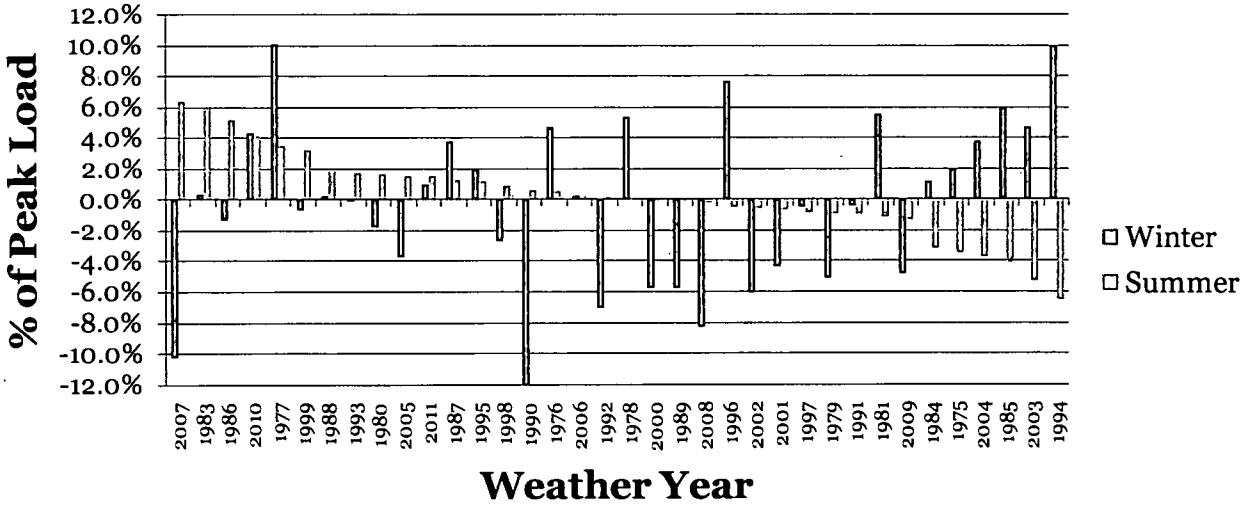
Month	Energy (MWh)	Peak Load (MW)
January	9,163,558	18,891
February	8,191,438	18,033
March	7,845,982	16,797
April	7,311,837	14,012
May	7,885,201	16,407
June	9,015,082	18,675
July	9,509,029	19,476
August	9,595,229	19,075
September	8,256,070	17,595
October	7,486,890	14,687
November	7,541,890	16,048
December	8,669,874	17,756

Table 1 displays the peak and energy forecasts for 2016 under normal weather conditions. The company is expected to have a winter peak of 18,891 MW and a summer peak of 19,476 MW. All values include the reduction for energy efficiency but exclude any other DSM reductions.

To model the effects of weather uncertainty, 37 historical weather years were developed to reflect the impact of weather on load. A neural network program was used to develop relationships between weather observations and load based on the last five years of historical weather and load. Different relationships were built for each month of the year using hourly temperature, time of day, day of week, 8 hour prior temperature, 24 hour prior temperature, 48 hour prior temperature, and heating and cooling degree hours.

These relationships were then applied to the last 37 years of weather to develop 37 load shapes for 2016. Equal probabilities were given to each of the 37 load shapes in the simulation. Figure 1 ranks all weather years by peak summer load for the system. In the most severe weather conditions, the summer peak can be approximately 6% higher than the peak under normal weather conditions and 10% for the winter. The reason for the larger variation in winter loads is the larger variation of temperature versus normal weather of 10 to 13 degrees whereas in the summer maximum variation versus normal weather is only 6 degrees.

Figure 1. Peak Load Variability Vs. Normal Weather



The difference in frequency of high load periods during winter versus summer can be seen in Figure 2. The duration of high load is far less in the winter causing the summer to have higher reliability risk. So despite higher variation in winter peak loads, sustained high loads in the summer cause the majority of reliability events.

Figure 2. Frequency of High Load Hours for Winter and Summer

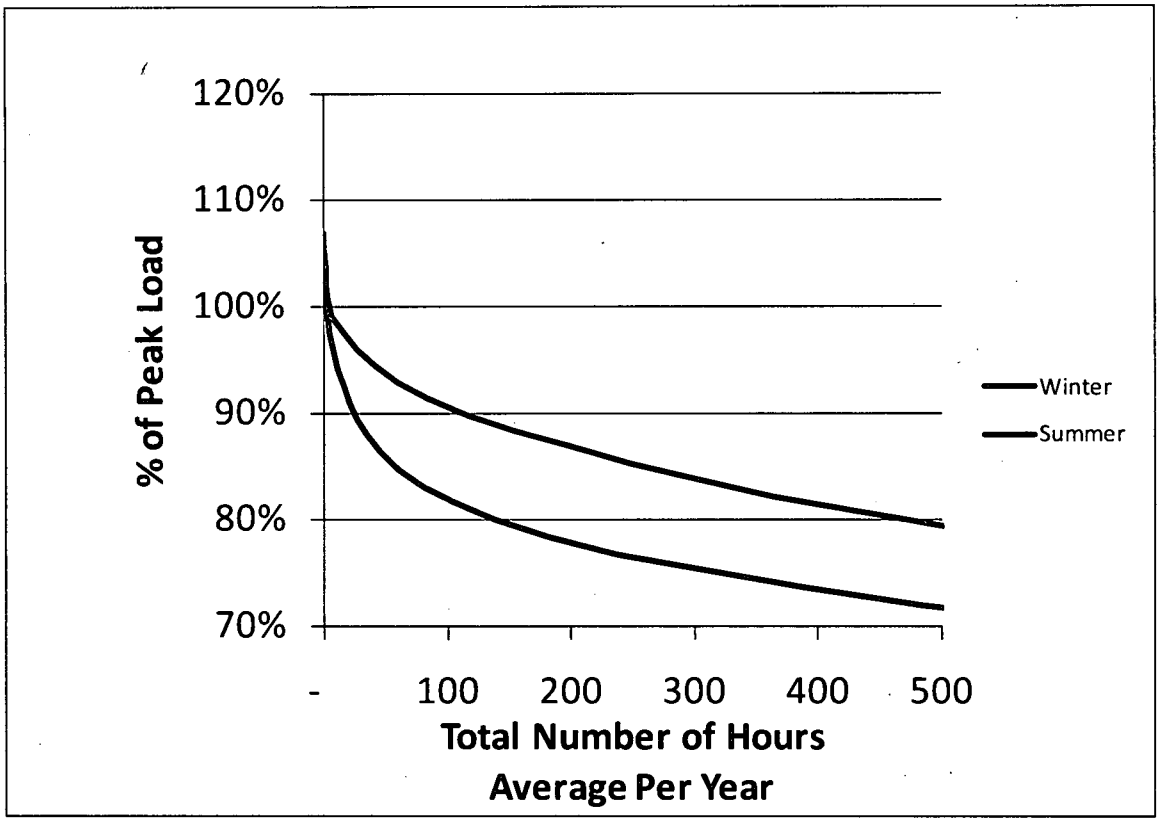


Table 2 summarizes the combined summer and winter peaks by weather year. The table shows that recent years including 2007 and 2010 were among the most severe summers.

Table 2. 2016 Peak Load Rankings for All Weather Years

Summer Peaks

Max	20,721	6.40%
Forecast	19,476	

Winter Peaks

Max	20,798	10.1%
Forecast	18,891	

Rank	Year	Peak	Versus Forecast (%)	Rank	Year	Peak	Versus Forecast (%)
1	2007	20,721	6.4%	1	1977	20,798	10.1%
2	1983	20,634	5.9%	2	1982	20,798	10.1%
3	1986	20,485	5.2%	3	1994	20,778	10.0%
4	2010	20,289	4.2%	4	1996	20,347	7.7%
5	1977	20,156	3.5%	5	1985	20,015	5.9%
6	1999	20,106	3.2%	6	1981	19,944	5.6%
7	1988	19,856	2.0%	7	1978	19,902	5.4%
8	1993	19,808	1.7%	8	2003	19,790	4.8%
9	1980	19,789	1.6%	9	1976	19,777	4.7%
10	2005	19,777	1.5%	10	2010	19,713	4.3%
11	2011	19,772	1.5%	11	1987	19,614	3.8%
12	1987	19,729	1.3%	12	2004	19,605	3.8%
13	1995	19,702	1.2%	13	1995	19,259	1.9%
14	1998	19,645	0.9%	14	1975	19,254	1.9%
15	1990	19,600	0.6%	15	1984	19,121.20	1.2%
16	1976	19,583	0.6%	16	2011	19,082	1.0%
17	2006	19,533	0.3%	17	1983	18,950	0.3%
18	1992	19,517	0.2%	18	2006	18,947	0.3%
19	1978	19,492	0.1%	19	1988	18,934	0.2%
20	2000	19,462	-0.1%	20	1993	18,884	0.0%
21	1989	19,461	-0.1%	21	1991	18,823	-0.4%
22	2008	19,429	-0.2%	22	1997	18,801	-0.5%
23	1996	19,388	-0.4%	23	1999	18,761	-0.7%
24	2002	19,362	-0.6%	24	1986	18,650	-1.3%
25	2001	19,345	-0.7%	25	1980	18,561	-1.7%
26	1997	19,317	-0.8%	26	1998	18,383	-2.7%
27	1979	19,300	-0.9%	27	2005	18,192	-3.7%
28	1991	19,288	-1.0%	28	2001	18,068	-4.4%
29	1981	19,247	-1.2%	29	2009	17,969	-4.9%
30	2009	19,225	-1.3%	30	1979	17,929	-5.1%
31	1984	18,859	-3.2%	31	2000	17,809	-5.7%
32	1975	18,797	-3.5%	32	1989	17,807	-5.7%
33	2004	18,750	-3.7%	33	2002	17,745	-6.1%
34	1985	18,670	-4.1%	34	1992	17,551	-7.1%
35	2003	18,446	-5.3%	35	2008	17,325	-8.3%
36	1994	18,202	-6.5%	36	2007	16,953	-10.3%
37	1982	17,849	-8.4%	37	1990	16,130	-15%

From an annual energy perspective, the following table shows the top 10 highest weather years. Table 3 shows that 2010 had energy consumption 5% higher than normal as both winter and summer seasons were severe. The second highest weather year was only 2.5% higher than average energy.

Table 3. Weather Years Ranked by Total Energy

Annual Energy
Top 10

Max	106,073,456	5.0%
Forecast	101,065,715	

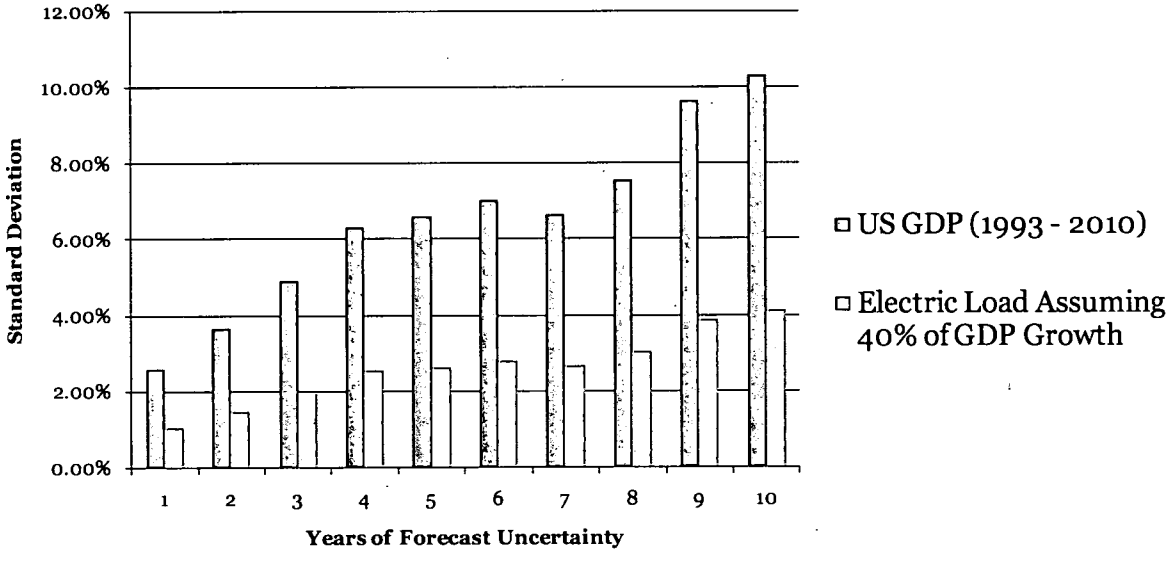
Rank	Year	Peak	Versus Forecast (%)
1	2010	106,073,456	5.0%
2	1977	103,627,852	2.5%
3	1993	103,014,691	1.9%
4	1980	102,568,028	1.5%
5	1987	102,319,099	1.2%
6	1978	102,300,173	1.2%
7	1986	102,249,879	1.2%
8	2007	102,241,193	1.2%
9	1981	102,065,451	1.0%
10	1988	101,879,158	0.8%

C. Load Forecast Error

An analysis was performed using the historical Congressional Budget Office four year prior forecasts of GDP and comparing those forecasts to actual data from 1993 – 2010. Comparing how well GDP was predicted four years in advance provides insight into the economic uncertainty that should be applied to utility loads. The chart below shows the standard deviation of historical GDP forecast error for forecasting one to ten years in advance. As expected, the standard deviation of forecast error increases as the number of years increase. Based on discussions with Duke, electric load is assumed to grow at about 40% of GDP growth. Assuming four year forecast error, standard deviation for load forecast error

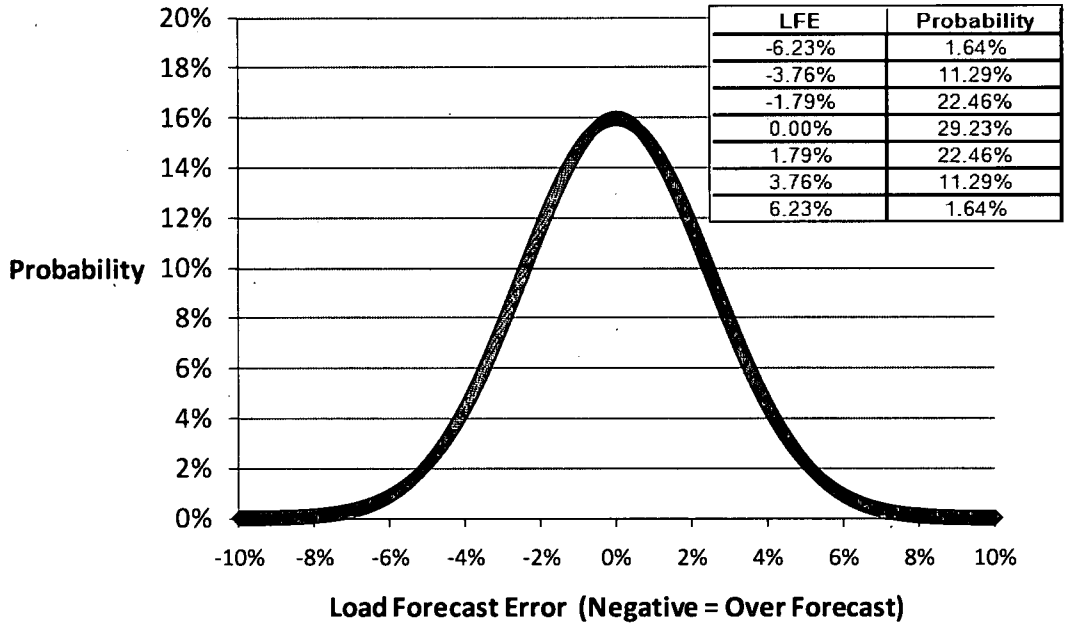
uncertainty for utility load is 2.5% as shown in the following figure. If lead times for new generation changed substantially, then the standard deviation used to develop the economic load forecast error would need to be adjusted accordingly. However, it is unlikely that typical generation resources can be installed and brought in-service in less than three to four years given the time needed for environmental and regulatory approvals, construction, and startup testing.

Figure 3. Standard Deviation of GDP forecast error (1 to 10 Year Projections)



Astrape also performed a comparison of the company's historical four year prior forecasts to actual weather normalized load. Astrape observed that in recent years there was a tendency to over forecast given the economic downturns seen in the last decade. However, the standard deviation of load forecast error was 3.34%, which was in the range of the CBO study. The company and Astrape determined that using 2.5% was a reasonable value for the standard deviation and Astrape developed a normal distribution as shown in the following Figure 4. The continuous distribution was converted into a discrete distribution with the 7 points shown for use in determining discrete scenarios to be modeled. As an example of how to interpret the economic uncertainty data, there is a 1.64% chance that load will be 6.23% greater than forecasted.

Figure 4. Load Forecast Error



LFE	Probability
-6.23%	1.64%
-3.76%	11.29%
-1.79%	22.46%
0.00%	29.23%
1.79%	22.46%
3.76%	11.29%
6.23%	1.64%

SERVM utilized each of the 37 weather years and applied each of these seven load forecast error points to create 259 different load scenarios.

D. Resources

The resources and seasonal capacities for the 2016 study are shown in the following tables.

Table 4. Nuclear Resource Capacities (MW)

Unit Name	January	July
Catawba 1	891	857
Catawba 2	881	847
McGuire 1	900	844
McGuire 2	900	844
Oconee 1	875	856
Oconee 2	875	856
Oconee 3	875	856
Totals	6,196	6,196

Table 5. Baseload and Intermediate Resource Capacities (MW)

Unit Name	January	July
Allen 1	167	162
Allen 2	167	162
Allen 3	270	261
Allen 4	282	276
Allen 5	275	266
Belews Creek 1	1135	1110
Belews Creek 2	1135	1110
Cliffside 5	562	556
Cliffside 6	825	825
Marshall 1	380	380
Marshall 2	380	380
Marshall 3	658	658
Marshall 4	660	660
Buck CC	508	500
Buck CC Duct	120	120
Dan River CC	508	500
Dan River CC Duct	120	120
CPL SOR A	2	2
CPL SOR D	3	3
CPL SOR E	2	2
NUG	26	26
Totals	8,185	8,079

Retired by 2016
Buck 3
Buck 4
Buck 5
Buck 6
Cliffside 1
Cliffside 2
Cliffside 3
Cliffside 4
Dan River 1
Dan River 2
Dan River 3
Riverbend 4
Riverbend 5
Riverbend 6
Riverbend 7

Table 6. Peaking Resource Capacities (MW)

Unit Name	January	July
Lee 1 NG	100	100
Lee 2 NG	100	102
Lee 3 NG	170	170
Lee CT1	41	41
Lee CT2	41	41
Lincoln CT1	93	79.2
Lincoln CT2	93	79.2
Lincoln CT3	93	79.2
Lincoln CT4	93	79.2
Lincoln CT5	93	79.2
Lincoln CT6	93	79.2
Lincoln CT7	93	79.2
Lincoln CT8	93	79.2
Lincoln CT9	93	79.2
Lincoln CT10	93	79.2
Lincoln CT11	93	79.2
Lincoln CT12	93	79.2
Lincoln CT13	93	79.2
Lincoln CT14	93	79.2
Lincoln CT15	93	79.2
Lincoln CT16	93	79.2

Unit Name	January	July
MillCreek CT1	92	74
MillCreek CT2	92	74
MillCreek CT3	92	74
MillCreek CT4	92	74
MillCreek CT5	92	74
MillCreek CT6	92	74
MillCreek CT7	92	74
MillCreek CT8	92	74
Rockingham CT1	165	165
Rockingham CT2	165	165
Rockingham CT3	165	165
Rockingham CT4	165	165
Rockingham CT5	165	165
Anson Hamlet CT	4	4
CPL Peaking CT	2	2
IRP CT 1	900	740
IRP CT 2*	0	740

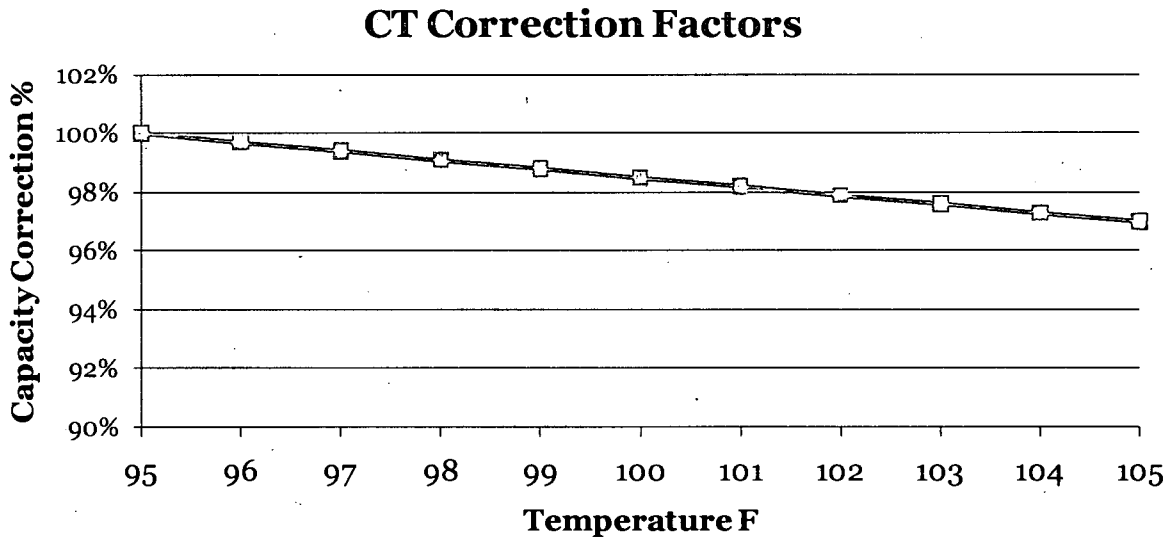
Retired by 2016
Buck CT1
Buck CT2
Buck CT3
Buzzard Roost CT1
Buzzard Roost CT2
Buzzard Roost CT3
Buzzard Roost CT4
Buzzard Roost CT5
Buzzard Roost CT6
Buzzard Roost CT7
Buzzard Roost CT8
Buzzard Roost CT9
Buzzard Roost CT10
Dan River CT1
Dan River CT2
Riverbend CT1
Riverbend CT2
Riverbend CT3
Riverbend CT4

Totals	4,410	4,628

*IRP CT 2 is in service in June, 2016

All summer ratings in the previous tables are based on 95 degree F. On an hourly basis, SERVM can adjust the capacity of each resource based on the historical hourly temperature for the weather year being modeled. Because the maximum output of peaking units degrades as temperatures increase, the derating multipliers in Figure 5 were utilized to derate the units above 95 F. The multipliers were developed based on the Duke CT fleet which assumes a degradation of 0.3% of capacity per degree. This ensures correlation of capacity output with load since both are highly dependent on the hourly temperature.

Figure 5. Summer Rating Capacity Multipliers



The hydro portfolio is modeled in segments that include Run of River (ROR), Scheduled (Peak Shaving), and Emergency Capacity. The Run of River segment is dispatched as base load capacity providing its designated capacity every hour of the year. The scheduled hydro is used for shaving the daily peak load but also includes minimum flow requirements. If included, the emergency capacity is used only to prevent firm load shed and the model allows the emergency mode to "borrow" energy from the future dispatch of the scheduled hydro portion with the constraint that the energy amount is enough for only a few hours. Typically hydro resources are not able to be dispatched at their nameplate capacity during peak hours due to water constraints or river flow requirements as seen in 2008. By modeling the hydro resources in these three segments, the model captures the appropriate amount of capacity dispatched during peak periods. See the confidential Appendix for the details regarding hydro capacities.

Figure 6 shows the total breakdown of scheduled versus emergency hydro based on the last 37 years of weather. Out of the total 1,100 MW of capacity owned by the company, only 442 MW on average is dispatched during peak periods. During drought years, less than 390 MWs are dispatched on peak in specific months. For this reason, the use of emergency hydro was not included in the base case results due to recent experience, but a sensitivity was performed that included the additional emergency hydro capacity which could be utilized for a few hours per month.

Figure 6. Scheduled Capacity versus Emergency Capacity

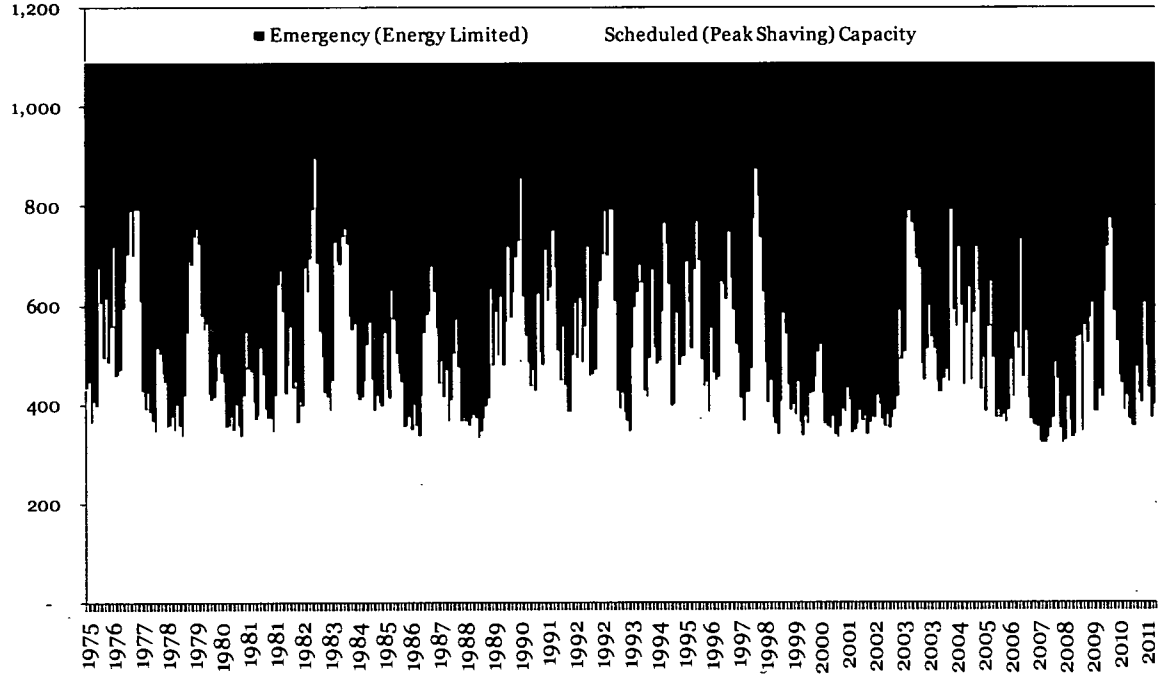


Figure 7 demonstrates the variation of hydro energy by weather year which is input into the model. The drought shown in 2001, 2007, and 2008 is captured in the reliability model.

Figure 7. Hydro Energy by Weather Year

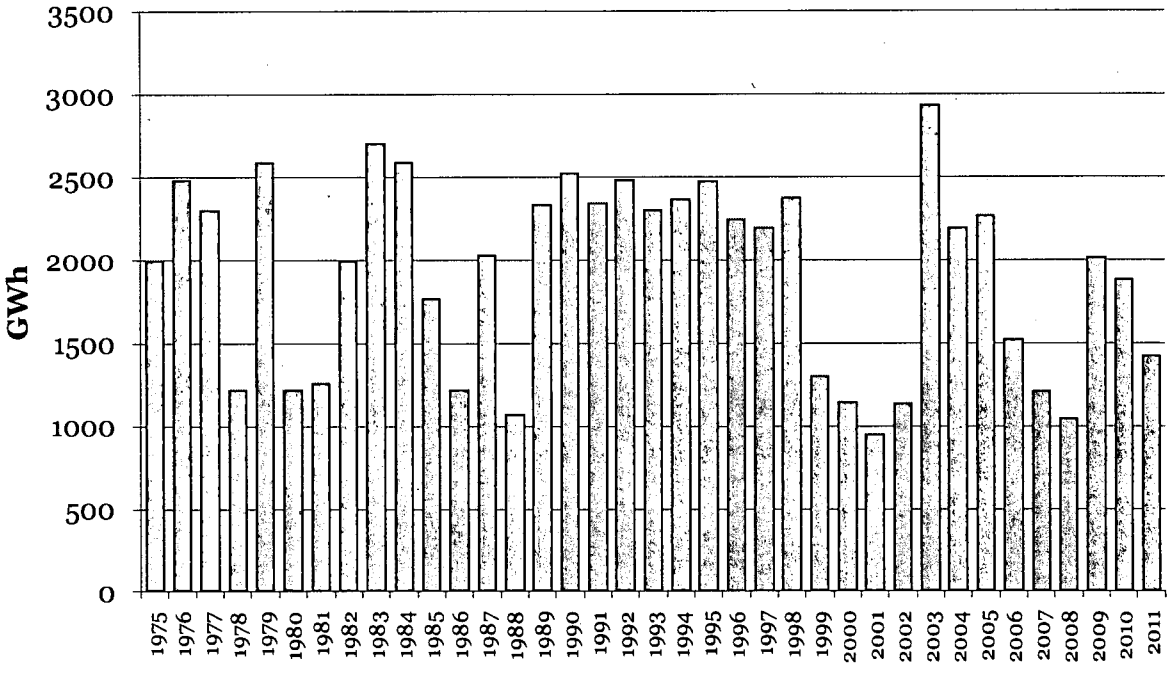


Figure 8 compares actual history of the dispatch level of the hydro resources for a 2008 and 2009 as a percentage of time versus how the model dispatches the resources. The figure demonstrates the drought conditions that were seen in 2008 and also shows that the model is capturing a realistic dispatch of the hydro resources.

Figure 8. Hydo Dispatch Calibration: Percent of Time above Capacity Threshold

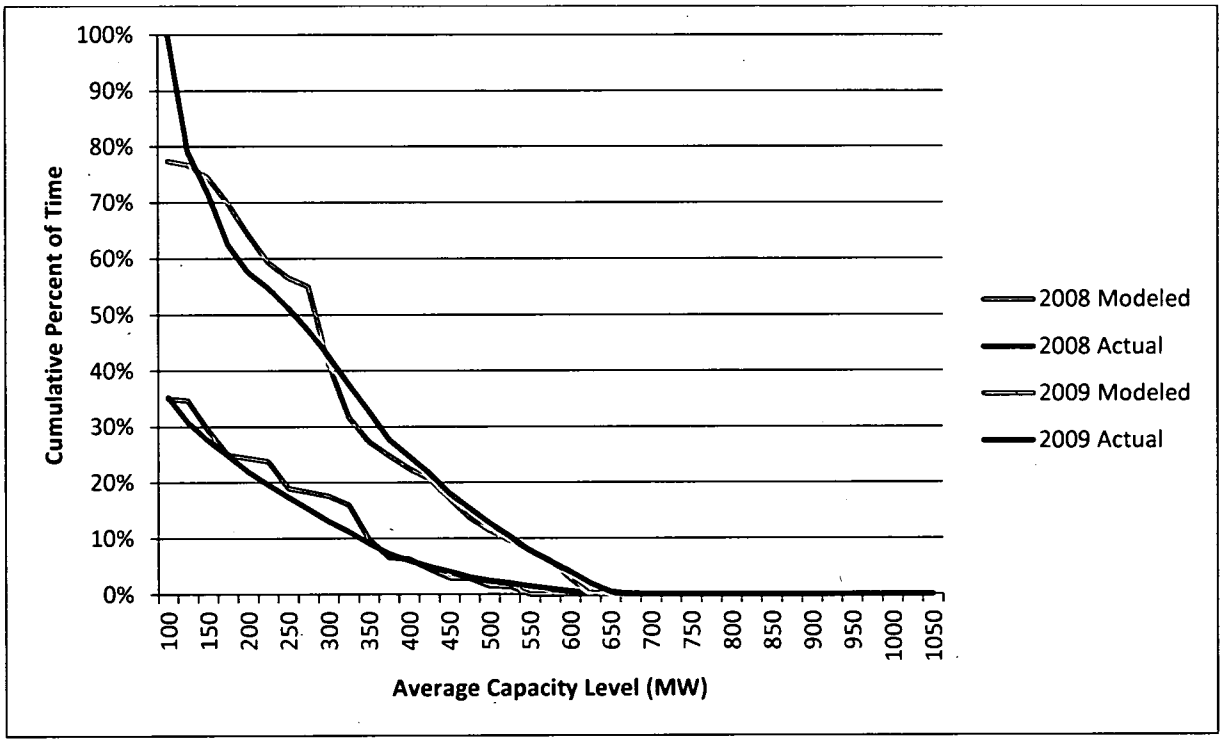


Table 7. Pump Storage Resources

Unit Name	January	July	Reservoir Capacity (MWh)	Reservoir Generating Hours
Bad Creek	1360	1360	33,030	24
Jocasse	780	780	57,540	74
Total	2140	2140		

Pumping for pumped storage occurs anytime energy is available. During constrained periods, pumped storage resources are given dispatch priority to maintain a maximum level in the storage ponds. During less constrained periods, the dispatch order is switched so that the energy is used before CT's are dispatched. SERVM uses any excess capacity to fill up the ponds including economic purchases from the

market. In actual practice, this process may be performed slightly differently to minimize production cost during off-peak periods. However, the model architecture is appropriate for reliability modeling, because it is always economic to build up the reservoirs of storage units with any generating asset available if that is what is required to have the units available to operate to avoid unserved energy.

Table 8. Renewable Resources

Unit Name	January	July
Solar – Nameplate Capacity	49	49
Wind – Nameplate Capacity	318	318
Landfill Gas	32	32
Poultry_PPA	14	14
Biomass_PPA	134	134
Totals	547	547

For reserve margin calculations, Solar capacity is given a 50% capacity credit and wind capacity is assumed to have a 15% capacity credit. For these resources, an 8760 hourly generation shape was used. The average summer and winter shapes are shown in Figure 9 and Figure 10. For each day, SERVM draws a daily shape from all the days in the month. Because historical data is unavailable, this random draw is used for all weather years.

Figure 9. Solar Profile

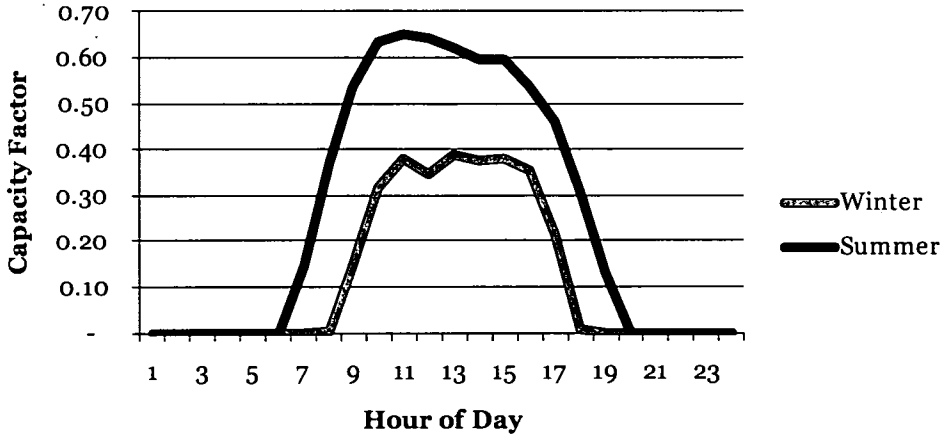
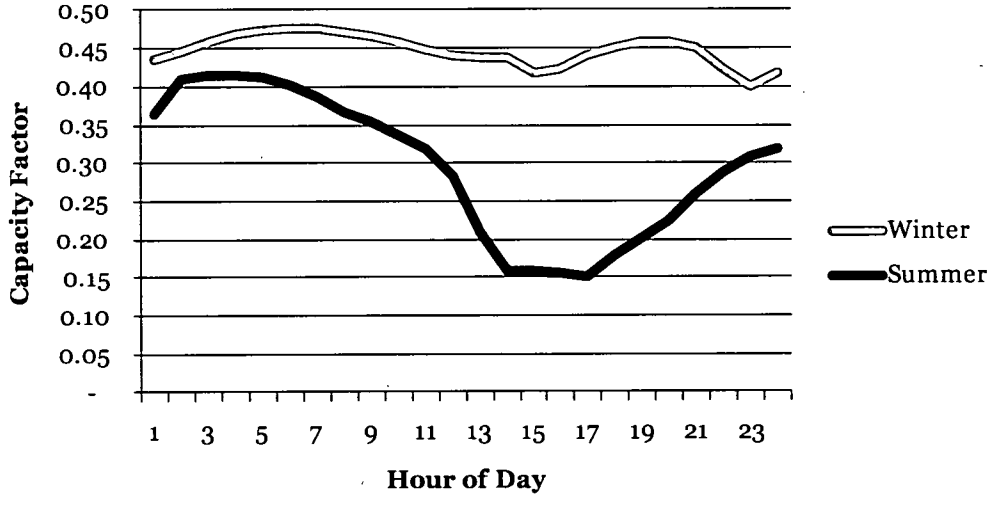


Figure 10. Wind Profile



E. Unit Outage Data

Unlike typical production cost models, SERVM does not use an EFOR for each unit as an input. Instead, historical GADS data events are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. For this RM Study, 2007-2011 GADS events were entered into SERVM. The events are entered using the following variables:

Full Outage Modeling
Time-to-Repair Hours
Time-to-Fail Hours

Partial Outage Modeling
Partial Outage Time-to-Repair Hours
Partial Outage Derate Percentage
Partial Outage Time-to-Fail Hours

Maintenance Outages
Maintenance Outage Percentage - % of full outages that are maintenance outages. SERVM uses this percentage and allows units to remain online until the following weekend if they are needed in the short term.

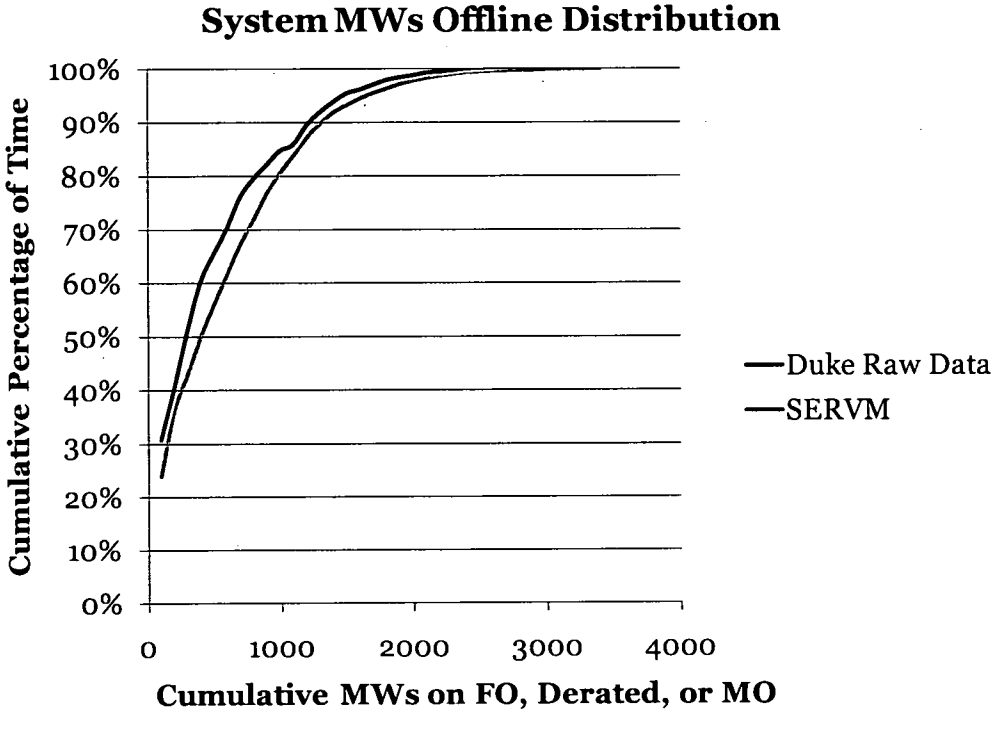
For example purposes, assume that from 2007 – 2011, Allen 1 had 15 full outage events and 30 partial outage events reported in the GADs data. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data along with the other variables listed above. These multiple Time-to-Repair and Time-to-Fail distributions are used by SERVM. Because typically there is an improvement in EFOR across the summer, the data is typically broken up into seasons resulting in a set of Time-to-Repair and Time-to-Fail inputs for summer, off peak, and winter based on history. Assume Allen 1 is online in hour 1 of the simulation. SERVM will randomly draw a Time-to-Fail value from the distribution provided for both full outages and partial outages. The unit will run for that amount of time before failing. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new

Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture.

Unit Outage Calibration

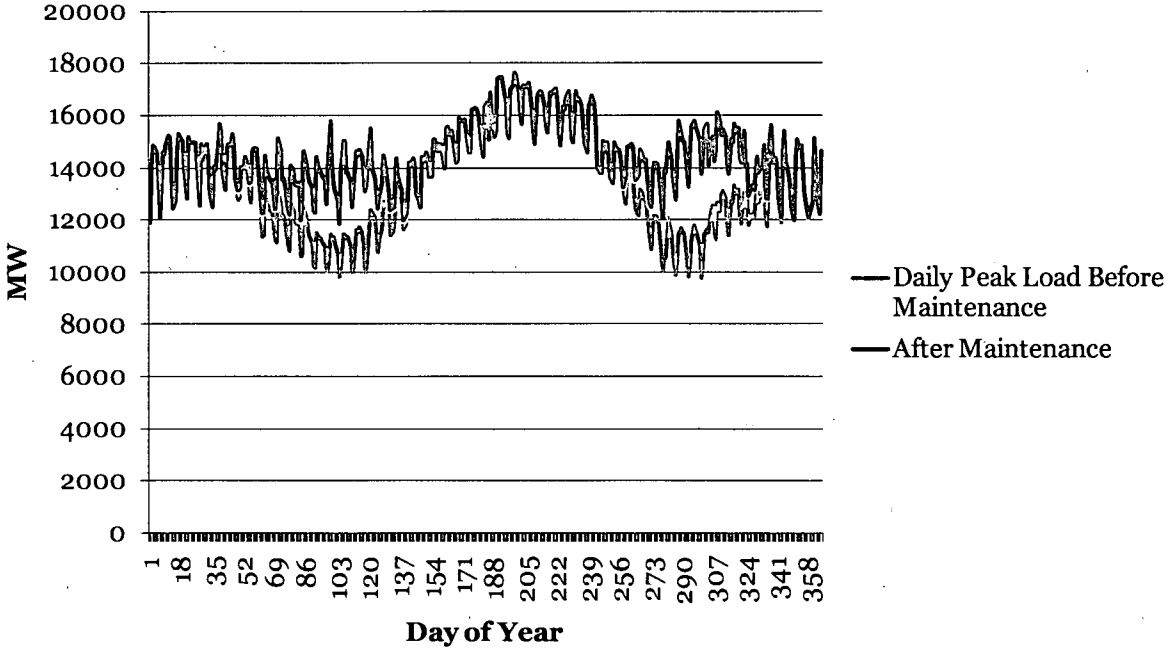
The critical aspect of unit performance modeling for a reliability study is the cumulative MW offline distribution. Most reliability problems are due to significant coincident outages. Figure 11 shows the distribution of outages for Duke Energy. The model has been calibrated to ensure this distribution is captured. Based on the data in the figure 10, the company may have 1,000 MW of capacity offline in 15% of all the hours. This equates to approximately 5% in reserve margin unavailable. System and individual outage rates are located in the confidential Appendix of this report. System and individual outage rates are located in the confidential Appendix of this report.

Figure 11. System Capacity Offline as a Percentage of Time



To capture the impact of planned maintenance, the 2016 maintenance schedule was modeled which removes capacity during the shoulder months of the year. Figure 12 shows that when planned maintenance is assumed in the shoulder months that the resulting load level between winter and shoulder periods is relatively flat.

Figure 12. Daily Peak Load Plus Planned Maintenance Requirement



F. Demand Response

A total of 987 MWs of demand response were modeled in the simulation. Energy efficiency (EE) was directly removed from load in the simulation while the resources in Table 9 were modeled as resources to be called upon given a reliability event. SERVM takes into account the constraints on demand response and dispatches accordingly. These constraints include a maximum number of hours per year, hours per day, days per week, and shadow dispatch price for the resources to be called.

Table 9. Demand Response Summary

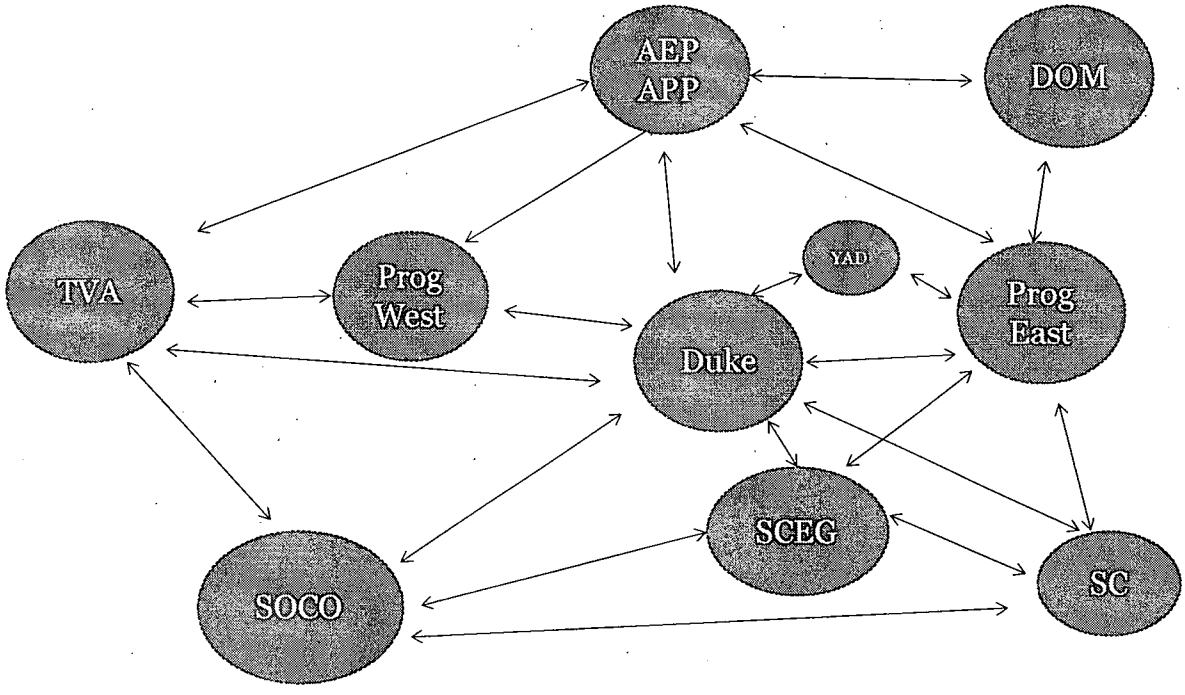
Unit Name	January Capacity	July Capacity	Hours Per Year Limit	Hours Per Day Limit	Days Per Week Limit
PowerManager	0	432	100	10	7
PowerShare0/5	8	9	40	8	7
PowerShare5/5	8	9	40	8	3
PowerShare10/5	8	9	40	8	3
PowerShare15/5	8	9	40	8	3
PowerShare_Mand	381	381	100	10	7
PowerShare_Generator	14	14	100	10	7
PowerShare_IS	111	110	150	10	7
PowerShare_SG	16	16	8760	24	7
Total	552	987			

G. Multi Area Modeling

The surrounding market must play a significant role in resource adequacy even for a utility the size of Duke Energy Carolinas. If several large generators are offline due to outage during peak season, it is likely that the company would depend on market purchases from surrounding regions.

The market representation used in SERVM was developed through consultation with Duke Energy Staff, EIA forms, Company Integrated Resource Plans (IRP), and reviews of NERC resource adequacy assessments. The base case level of reserves for neighbors is based on target reserve margins for surrounding neighbors. Using this methodology ensures that the company is not leaning on an external market more than is reasonable. Figure 13 shows the topology used for the region.

Figure 13. Regional Topology



Each neighbor's hourly loadshape was modeled based on historical hourly temperature data similarly to the Duke load. By using hourly weather, load diversity was captured for each neighboring area. Diversity of peak load is important to understand especially when examining physical reliability metric results. Table 10 shows the average diversity for summer months across all 37 years for each area. These values represent the percentage reduction from peak load that the neighbor is on average experiencing when Duke is experiencing its peak load. To ensure that Duke was not overstating the expectation of weather diversity and therefore available capacity from neighbors, Astrape believed it was prudent to cap the weather diversity in any given peak hour at 3%. A sensitivity assuming no weather diversity was simulated to understand the impact that weather diversity has on lowering the target reserve margin.

Table 10. Neighbor Diversity Factors

	Summer Diversity
SOCO	1.5%
AEP	1.7%
Dominion	1.9%
TVA	1.5%
SCEG	1.3%
Santee Cooper	1.3%
Progress East	1.2%
Progress West	3.3%

Table 11 displays a capacity and load summary of each of the neighbors including its current target reserve margin. The reserve margin calculations in this table assume that the interruptible capacity is included as a resource. While it is recognized that the region currently contains more capacity than these targets, it is not prudent to expect these additional reserves to be available long term. Outage rates for neighboring units were developed using existing Progress and Duke resources sorted by unit type and capacity size. Hydro resources reflect similar dispatch to the Progress and Duke hydro portfolios.

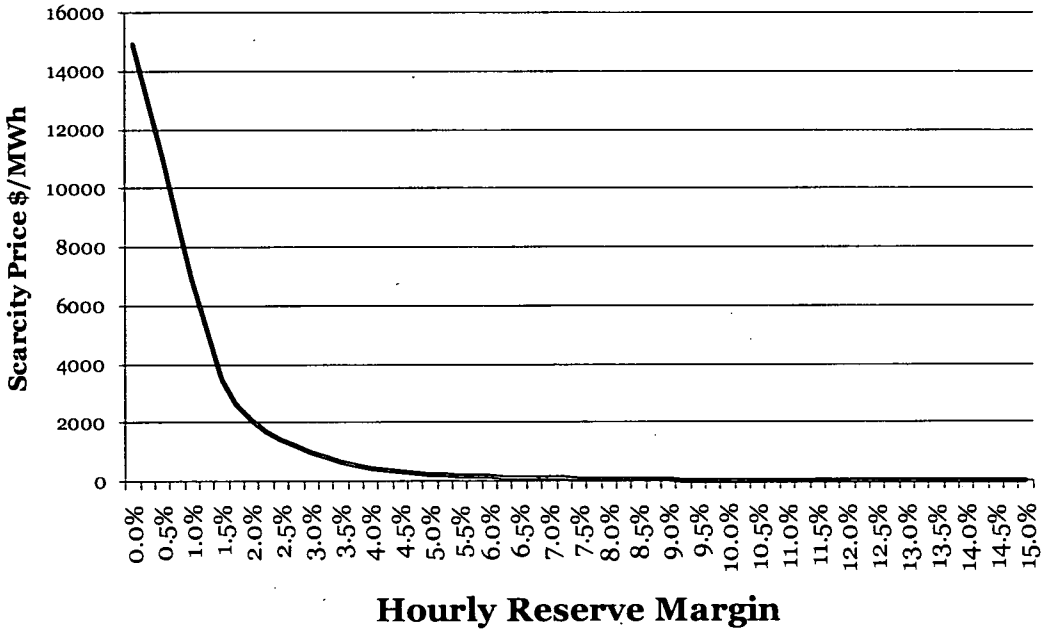
Table 11. Neighbor Capacity, Load, and Target Reserve Margin

	Progress	Southern Company	Santee Cooper	SCE&G	TVA	AEP_APP	DOM	Yadkin
Nuclear	3,563	6,895	318	2,066	7,832	0	3,501	
Coal and CC*	6,899	37,247	3,974	2,547	19,618	6,155	10,347	
Peaking	4,243	8,943	780	322	5,450	450	4,135	
Hydro	335	2,379	457	240	4,254	554	318	215
Pump Storage	0	1,186	0	576	1,739	238	3,003	
Interruptible	932	2,600	424	225	1,500	0	230	
Total Summer Capacity	15,972	59,249	5,953	5,976	40,393	7,397	21,534	215
Summer Peak Load	13,835	51,101	5,155	5,138	35,000	6,372	18,686	
Summer Reserve Margin	15.4%	15.9%	15.5%	16.3%	15.4%	16.1%	15.2%	

*includes renewable capacity

The costs of market purchases were calibrated using Duke Energy historical purchases and other market pricing data from the southeast region. As shown in Figure 14, scarcity pricing is based on the shortage in the specific region. As the excess capacity approaches zero, the price of capacity approaches the cost of unserved energy. Such an event is rare but can occur as a function of severe weather, poor unit performance, and significant load forecast error.

Figure 14. Scarcity Pricing Model



Available Transmission Capacity and TRM

The import capability is made up of Available Transmission Capability (ATC) and Transmission Reliability Margin (TRM). ATC is the non firm hourly transmission expected to be available in the market place while TRM is the portion of the transmission system that is held back for reliability needs. TRM is a fixed number while ATC is highly volatile. Due to its highly volatile nature, ATC is represented as a distribution to capture hours when there is little capacity to hours when there is abundance. The distributions used in SERVM are based on historical hours in 2011 during peak periods. It should be noted that these limits do not represent the amount of generation available from neighbors but only serve as the import constraint. Given these constraints, it is expected that the limiting factor will be generation availability from neighbors rather than transmission. However, transmission capability will be

a critical sensitivity in the final analysis. See the appendix for details regarding the values used for ATC and TRM.

H. Carrying Cost of Capacity

The cost of carrying incremental reserves was based on the capital cost, fixed O&M, and estimated transmission upgrades of four Advanced CTs with a total summer rating of 740 MW. The cost assumptions were based on estimates provided by Duke Energy. The appendix displays the characteristics and costs of the four CT site used to develop the capacity costs and the avoided and levelized costs by year.

I. Operating Reserve Requirements

Duke provides 500 MW of spinning reserves and 600 MWs of total operating reserves which was implemented into the model.

J. Cost of Unserved Energy

Unserved energy costs were derived based on information from national studies completed for the Department of Energy in 2003 and 2009. The national studies were compilations of other surveys performed by utilities over the last two decades. The national study split the customer classes into residential, small commercial and industrial, and large commercial and industrial. The 2009 study shows higher costs for commercial and industrial consumers compared to 2003. We expect that the costs of outages have risen rapidly in recent history for commercial and industrial customers due to the impact of technology; however both Duke and Astrape questioned the $92.16/kWh values shown in the 2009 Study for Small C&I. Given the magnitude of the values seen in both studies, Astrape and Duke determined that $15,000/MWh was a reasonable base case assumption Due to the infrequent nature of unserved energy; the sensitivity results demonstrate that this assumption is not the main driver of the results.

Table 12. Unserved Energy Costs

	Class Breakdown %	2003 DOE Study 2003$/kWh	2009 DOE Study 2008$/kWh	2003 DOE Study 2016$/kWh	2009 DOE Study 2016$/kWh
Residential	35%	1.15	1.10	1.45	1.27
Small C&I	37%	26.00	79.90	32.79	92.16
Large C&I	28%	15.00	23.80	18.92	27.45
Weighted Average $/kWh				17.93	42.23
Average of Studies $/kWh				30.08	

V. Simulation Methodology

Since most reliability events are high impact, low probability events, a large number of scenarios must be considered. Deterministic selection of extreme events will not give an accurate representation of the operation of any system during such an event, nor would it be possible to estimate a distribution of when such events could occur. For Duke Energy, SERVM utilized 37 years of historical weather and load shapes, 7 points of economic load growth forecast error, and 400 iterations of unit outage draws to represent the full distribution of realistic scenarios. The number of yearly simulation cases equals 37 weather years * 7 load forecast errors * 10 reserve margin levels = 2590 total cases. For each of these cases, 400 iterations of unit outage draws are performed which means over one million yearly simulations were completed for the analysis. From this analysis, expected reliability costs can be calculated and compared to the cost of adding additional reserves.

A. Case Probabilities

An example of probabilities given for each case is shown in Table 13. It is assumed that each weather year is given equal probability and each weather year is multiplied by the probability of each load forecast error point to calculate the case probability.

Table 13. Case Probability Example

Weather Year	Weather Year Probabilitiy	Load Forecast Error	Load Forecast Error Probability	Total Case Probability (Weather Yr Prob x LFE Prob)
1975	2.70%	-6.23%	1.64%	0.0443%
1975	2.70%	-3.76%	11.29%	0.3051%
1975	2.70%	-1.79%	22.46%	0.6070%
1975	2.70%	0.00%	29.23%	0.7900%
1975	2.70%	1.79%	22.46%	0.6070%
1975	2.70%	3.76%	11.29%	0.3051%
1975	2.70%	6.23%	1.64%	0.0443%
1976	2.70%	-6.23%	1.64%	0.0443%
1976	2.70%	-3.76%	11.29%	0.3051%
1976	2.70%	-1.79%	22.46%	0.6070%
1976	2.70%	0.00%	29.23%	0.7900%
1976	2.70%	1.79%	22.46%	0.6070%
1976	2.70%	3.76%	11.29%	0.3051%
1976	2.70%	6.23%	1.64%	0.0443%

For this study, reliability costs are defined as the following:

1) Carrying Cost of Reserves + Production costs above that of a CT + Imports above the cost of a CT + Expected Unserved Energy Costs - Sales above that of a CT

These components are calculated for each of the above cases and weighted based on probability to calculate an expected reliability cost for the year.

B. Reserve Margin and Capacity Margin Definition

For this study, reserve margin is defined as the following:

- Reserve Margin = (Resources – Demand) / Demand
  - Demand is the Average Summer System Peak Load and has not been reduced by Demand Response
  - Resources are defined based on summer ratings and include Demand Response
  - The solar capacity within the study was given a 50% capacity credit while wind was given a 15% capacity credit (consistent with the 2011 IRP)

VI. Base Case Results

A. Physical Reliability Results

From a physical reliability standpoint, Figure 15 shows LOLE in events per year and LOLH in hours per year for the base case. The one day in 10 year standard (LOLE = 0.1 events per year) falls at a 14.5% summer reserve margin and the LOLH is approximately 0.30 hours per year for that level of reserves. Figure 16 displays expected unserved energy (EUE) at varying levels of reserves. At the 14.5% reserve margin level, EUE is 170 MWh. As demonstrated in the additional sensitivities, physical reliability metrics are sensitive to input assumptions such as weather diversity, transmission availability, neighbor reserve levels, and emergency hydro assumptions.

Figure 15. Base Case LOLE and LOLH

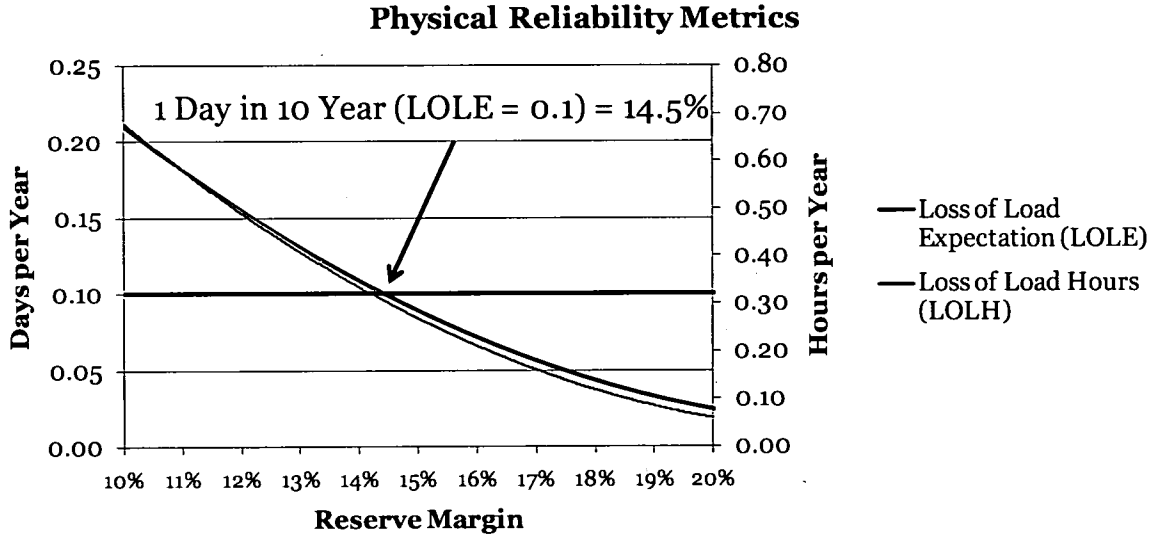
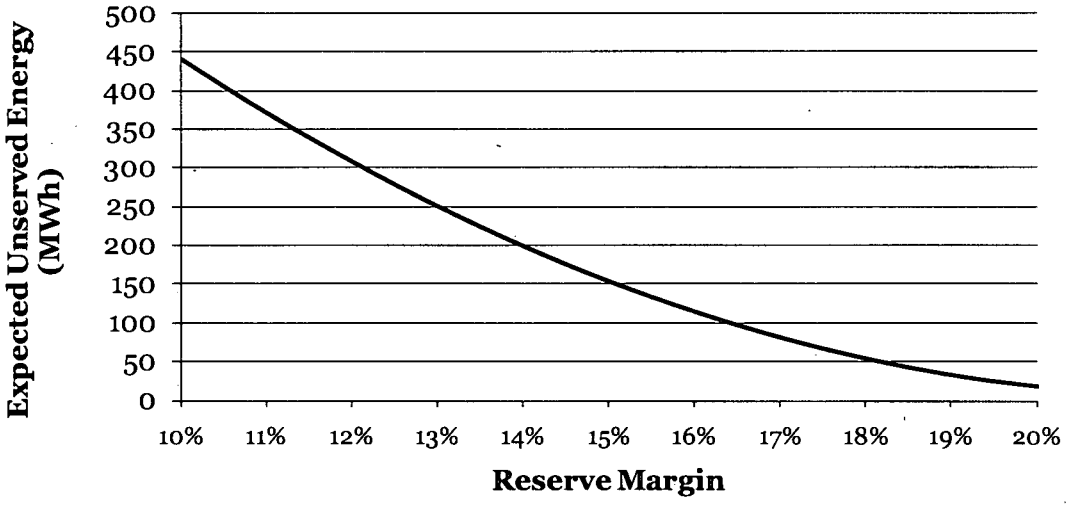


Figure 16. EUE

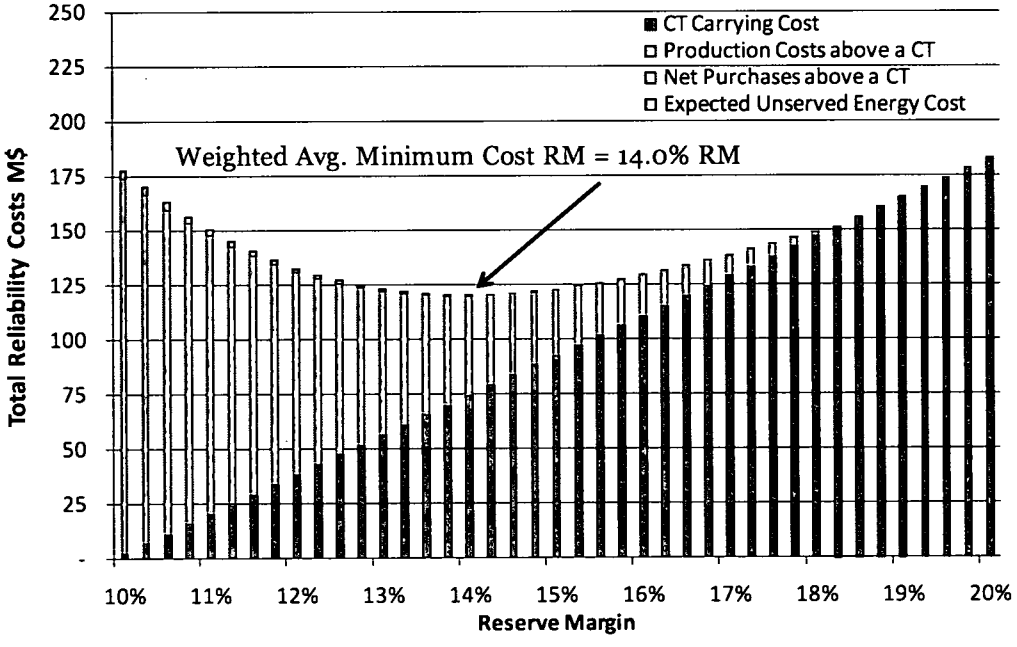


B. Economic Results

As previously discussed, physical reliability metrics only provide guidance for meeting a few peak load hours over a multi-year study period, and are therefore difficult to calibrate. To supplement the information provided by the base case LOLE analysis, economic reliability metrics were taken into consideration. Economic reliability costs include all costs from the next highest cost resource after a marginal CT all the way to the economic impact of shedding firm load. Since additional capacity will have some benefits in every year, this type of analysis is easily calibrated to actual practice and then allows accurate extrapolation to extreme scenarios. The base case economic results are shown in Figure 17. Based on these results, the long-term minimum cost reserve margin based on the weighted average of all results is 14%. As reserve margin increases, reliability energy costs (Production cost above a CT, net reliability imports above a CT, and cost of unserved energy) decrease while CT carrying cost increases. The flatness of the curve between 14% and 16% should be noted. Since resource additions are too large to perfectly target a reserve margin, some years will inevitably result in reserve margins that are higher

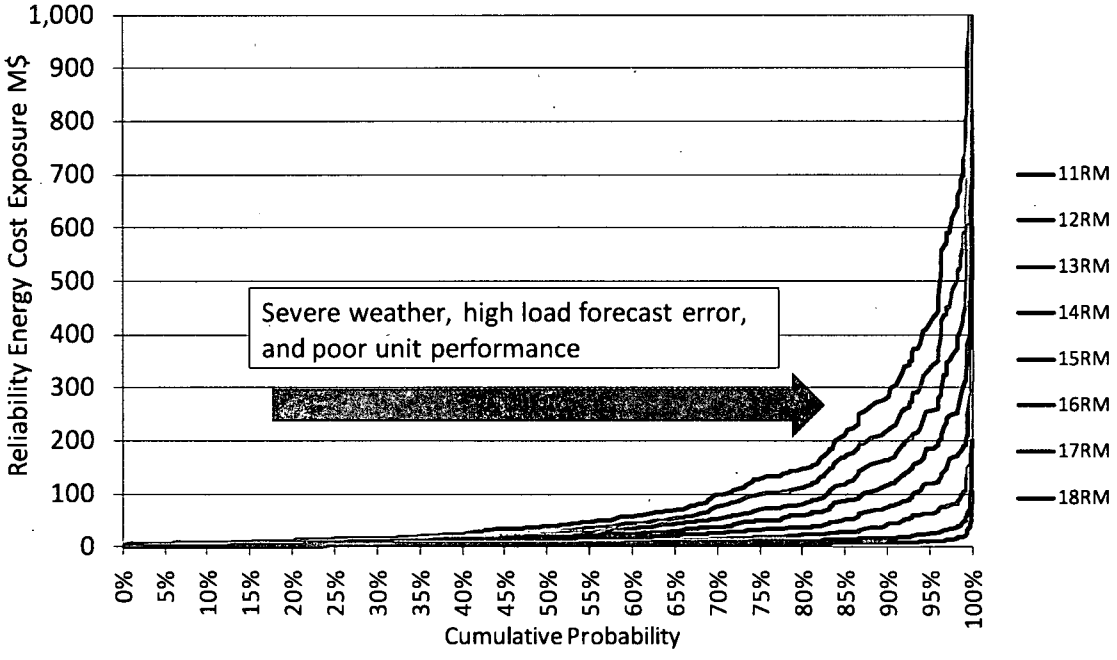
than the average economic optimum. The expected financial impact of these additions to the total system cost is not substantial, since the capacity above the weighted average target also brings some financial benefit. For example, the annual expected difference in cost between the 14% reserve margin and 16% reserve margin is only $9 million and the higher level of reserves may provide risk benefits.

Figure 17. Base Case Weighted Average Economic Reserve Margin



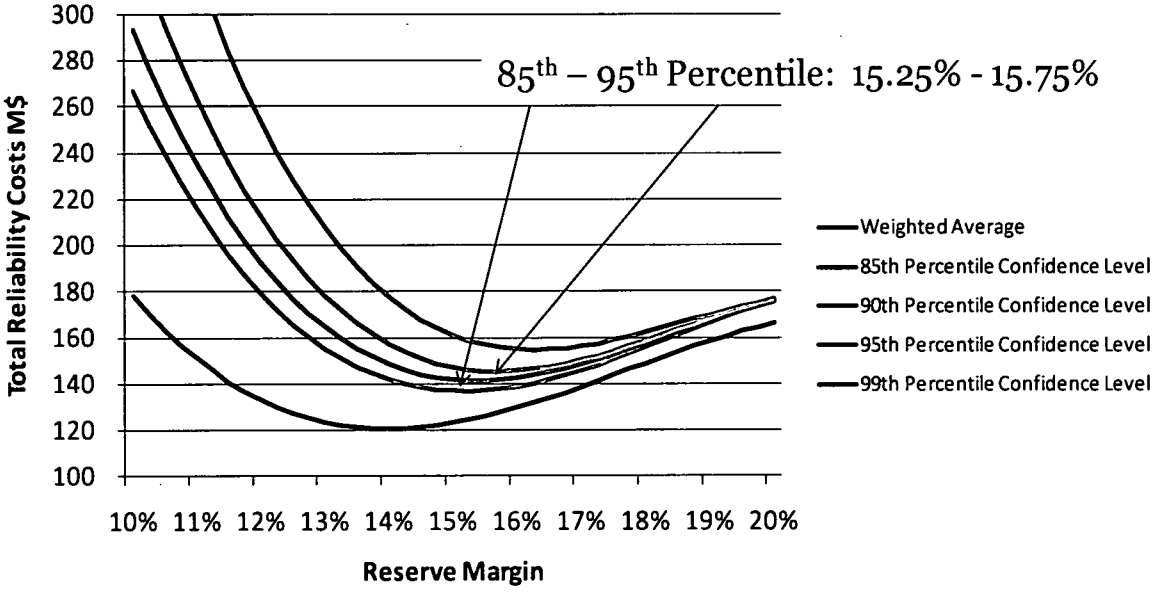
The previous figure represents the weighted average cost exposure and does not illustrate the high cost outcomes that can occur at each reserve margin level. While CT costs are mostly fixed, reliability energy costs are volatile dependent on the weather, load forecast error, or unit performance in a given year, so other confidence levels should be reviewed. While over a 30 year period this may be the optimal reserve margin, any single year can have significant risk at a 14% reserve margin level. Figure 18 shows the reliability energy costs on a probability weighted basis. At a 14% reserve margin, there is a 5% chance that reliability energy costs could exceed $185 million in any given year and a 1% chance that it could exceed $303 million.

Figure 18. Base Case Reliability Cost Exposure Distribution



Next we examined the optimal economic reserve margin recognizing the different risk profile of energy costs and capacity costs. By comparing capacity costs to reliability energy costs during years with extreme weather or poor unit performance as seen in Figure 18, we assessed the tail benefit of additional capacity. The reliability energy costs seen in Figure 18 were taken at different confidence levels (85%, 90%, 95%, and 99% probabilities) and added to the fixed capacity costs at each reserve margin to form the confidence level curves in Figure 19. This assessment showed that in 10% of all scenarios, Duke Energy would receive an economic benefit by adding efficient natural gas turbines up to a reserve margin of 15.50%. This is shown by the 90% confidence level (probability) curve in Figure 19. As we review the weighted average curve in the same figure we can see that by adding capacity to achieve a 16% reserve margin versus a 14% reserve margin, average annual costs only increase by $9 million, but the additional capacity acts as an insurance product to customers. In fact, 10% of the time customers would see their cost exposure decrease by at least $70 million as seen in Figure 18.

Figure 19. Risk Adjusted Reserve Margins



VII. Sensitivity Analysis

The following sensitivities were performed on the base case to only understand the movement in target reserve margins for both physical and economic metrics.

- Include Emergency Hydro: Allows the full nameplate capacity of the hydro fleet to be dispatched during peak periods.
- No Weather Diversity: All neighbors were given the same load shape as Duke to force all neighbors to peak at the same time.
- 50% ATC: The distributions of ATC were reduced by 50% to understand how transmission was impacting the base case results.
- Island Case: Duke is modeled as an island with no outside assistance.
- +2% Neighbor RM Level: The capacity of all neighbors was increased by a 2% reserve margin.
- +50% System EFOR: The EFOR for all Duke resources was increased by 50%.

- Marginal Resource Cost: +/- 25%: The capacity costs for the marginal resource was varied by +/-25%.
- EUE Cost: The cost of unserved energy was varied from $5,000/MWh to $25,000/MWh.
- 2023 Study Year: The study year was moved from 2016 to 2023. Load growth and generation expansion were included for each region and escalation in all economic factors such as the cost of EUE, scarcity pricing, and fuel prices was included for this sensitivity.

Table 14 shows the results of each sensitivity simulated. It is seen that the 0.1 LOLE reserve margin is more sensitive to key assumptions than the weighted average economic case. As discussed previously, this occurs because LOLE is impacted by only a few hours while economics looks at the broader economic impact of all costs above the costs of a CT.

The results show that LOLE is very sensitive to emergency hydro assumptions, weather diversity, and neighbor assistance while the economic results were more stable. Allowing the emergency hydro to be available during all peak periods decreases the LOLE target RM by 3.25% to 11.25% while the economic results were unchanged. Excluding weather diversity shifted the LOLE target up by 3.75 percentage points and the economic target up by 1 percentage point. Dividing the ATC distributions in half had a 1 percentage point impact on the LOLE target and a 2.5 percentage impact on economic results. The ATC sensitivity impacted transmission availability for every hour and so impacted the economic results more than LOLE. However, this sensitivity still indicates that even if substantial changes were to occur to the transmission system (loss of 50% of hourly available transmission capacity), target reserve margins would not need to shift dramatically. Increasing neighbor reserve levels by 2% shifted the LOLE target down by 3.75 percentage points and the economic target down by 0.75 of a percentage point. The island sensitivity should be seen purely as an academic exercise demonstrating the level of reserves the company would carry if it had no outside assistance. If Duke was a stand- alone utility, then it would need to carry reserves of 23.25%. In studying the year 2023, the target only changed slightly. It is expected that a long

term reserve margin study should evaluate an optimal target three to five years in the future and therefore 2023 would need to be reviewed again in the 2018 to 2020 time frame.

Regarding the Economic Sensitivities, the cost of unserved energy had little impact on the overall results since firm load shed events are so rare, however, the cost assumed for the marginal CT resource moved the economic reserve margin by approximately +/- .75 of a percentage point. As the marginal resource cost increases, the economic target decreases.

Table 14. Sensitivities

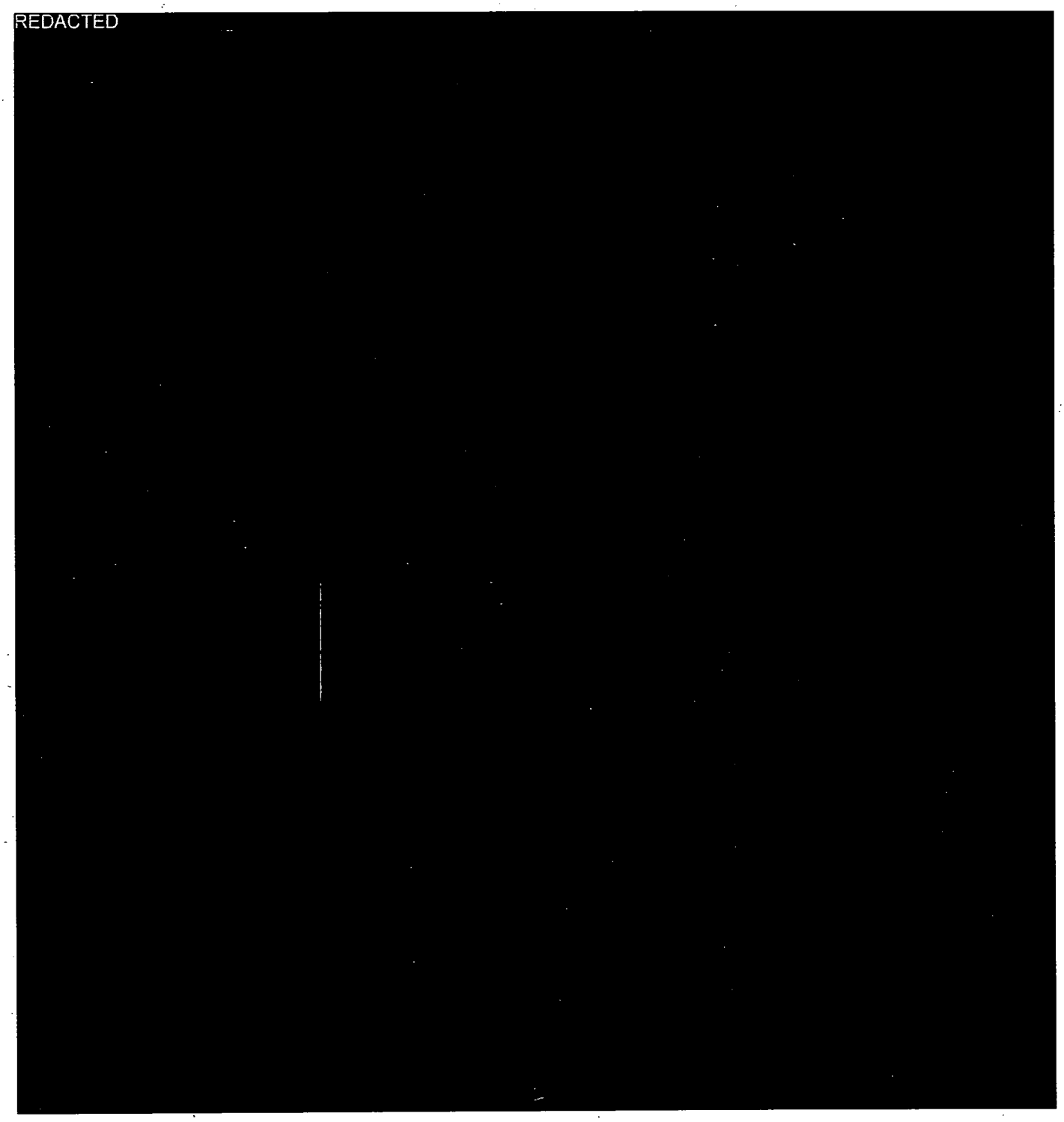
	Physical	Economics	
	LOLE: 1 in 10 Standard Target RM	Weighted Average Target RM	90% Target RM
Base Case	14.50%	14.00%	15.50%
Include Emergency Hydro	11.25%	14.00%	15.50%
No Weather Diversity	18.25%	15.00%	16.75%
50% ATC	15.50%	16.50%	17.50%
Island Case	23.25%		
+2% Neighbor RM	10.75%	13.25%	15.25%
+50% System EFOR	16.75%	16.25%	17.50%
2023 Study Year	14.25%	14.00%	15.75%
EUE Cost: $25,000/MWh		14.00%	15.75%
EUE Cost: $5,000/MWh		13.75%	15.25%
Marginal Resource Cost: +25%		13.25%	14.75%
Marginal Resource Cost: -25%		14.75%	16.00%

VIII. Conclusions/Recommendations

Astrape recommends that Duke set its absolute minimum reserve margin at the 14.5% LOLE target (LOLE = 0.1) and recommends a target of 15.50% based on the 90% confidence level economic target. Since capacity is added in large blocks to take advantage of economies of scale, the actual reserve margin will often be somewhat higher than the target of 15.5%. As shown in the charts and data above, a reserve margin target in the range of 14.5% to 16% produces similar total customer costs whether at the low end or high end of the range. To accommodate large resource additions such as nuclear, coal, or even larger combined cycle resources, the reserve margin would likely rise above the top end of the reserve margin range. However, the additional production cost and economy of scale benefits provided by such resources would likely justify their addition. Therefore, the recommended target reserve margin of 15.50% with a range of 14.5% to 16% should not be considered absolute as all resource decisions should be made on a case-by-case basis.

The results should be reviewed periodically as there are shifts in generation mix, DSM, intermittent resource penetration, or load shape that could impact results. Provided that the results are greatly impacted by regional reserve margins, it is also recommended that Duke keep a close eye on the surrounding market. Short term capacity decisions should also be reviewed on a case-by-case basis. Since physical capacity changes can rarely be implemented inside a 3-year window, the cost of any procurement should be weighed against the distribution of reliability events and the distribution of reliability costs associated with not purchasing the capacity. Even in cases when Duke is below its minimum target reserve margin, economic and physical reliability metrics may suggest not procuring additional capacity. Or an analysis may suggest purchasing more capacity than is needed to achieve the minimum target.

VIX. Confidential Appendix



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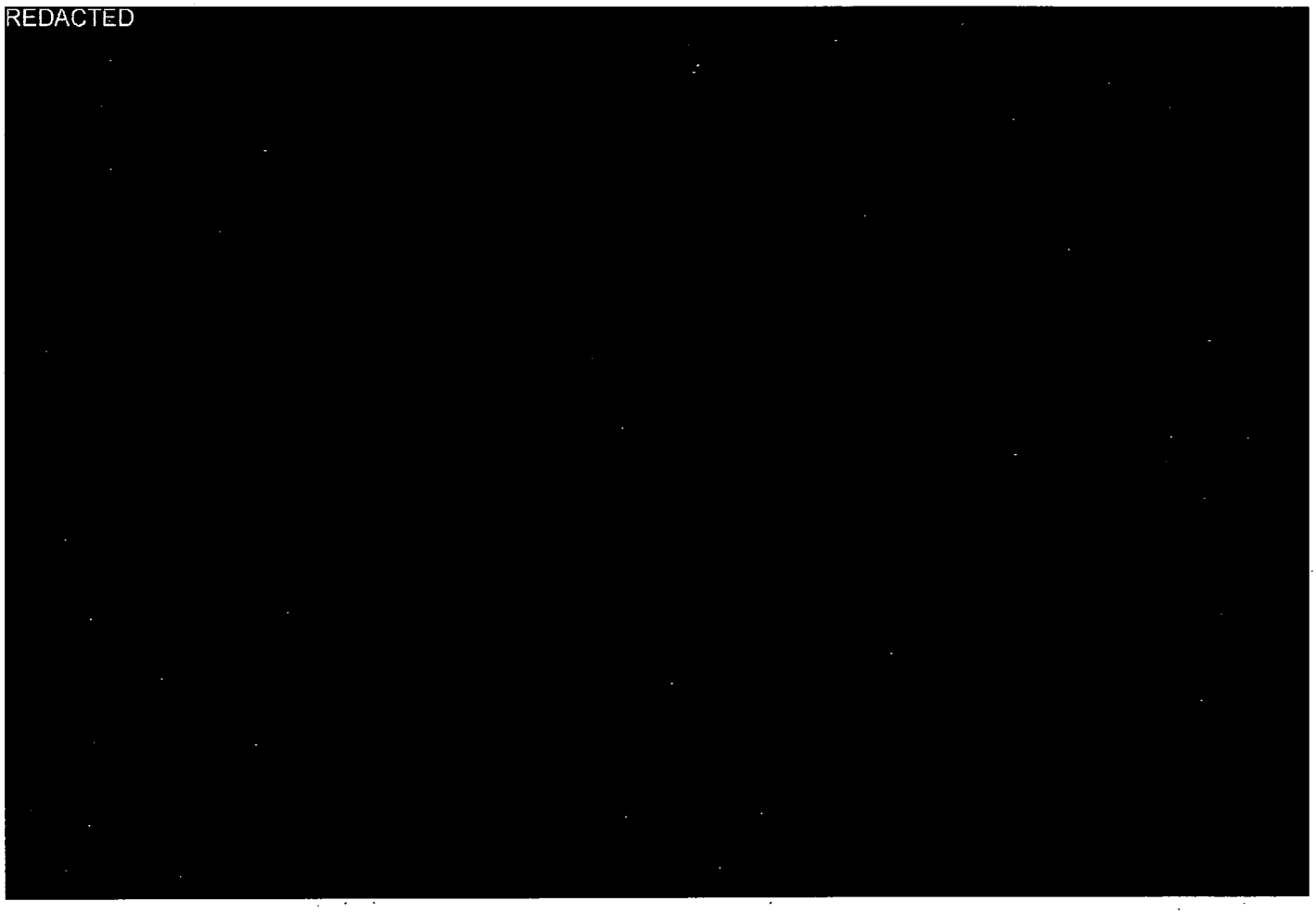

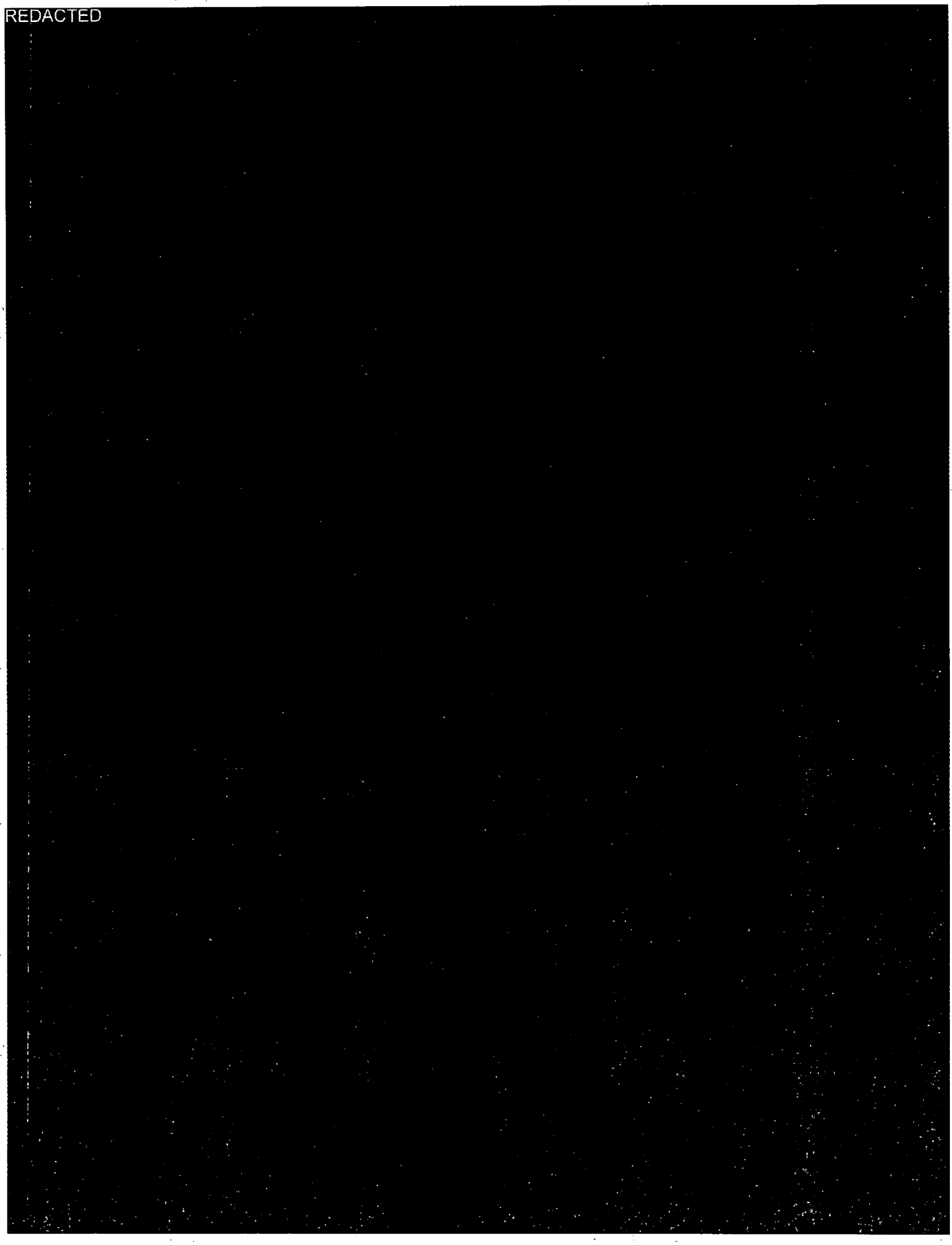
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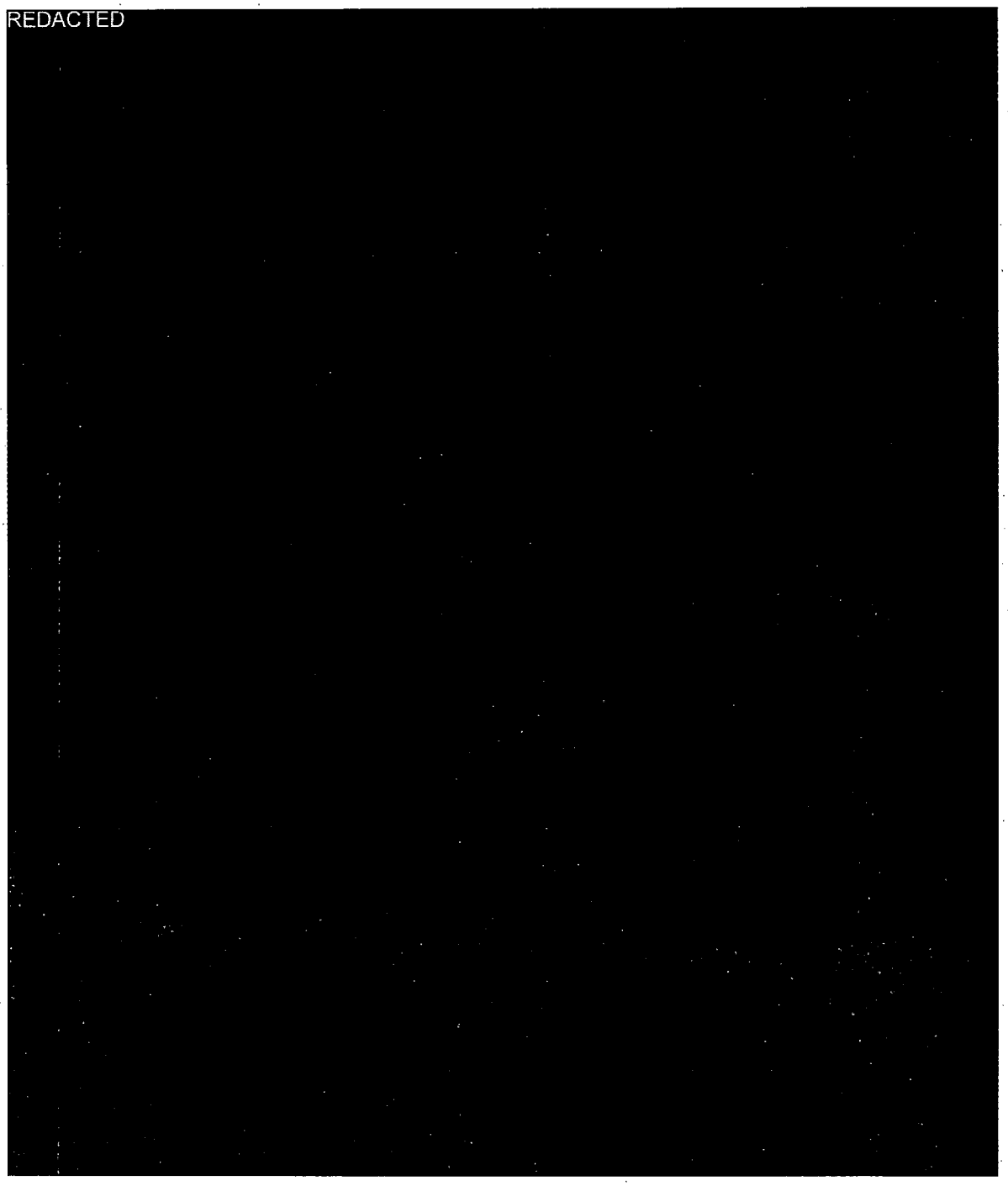

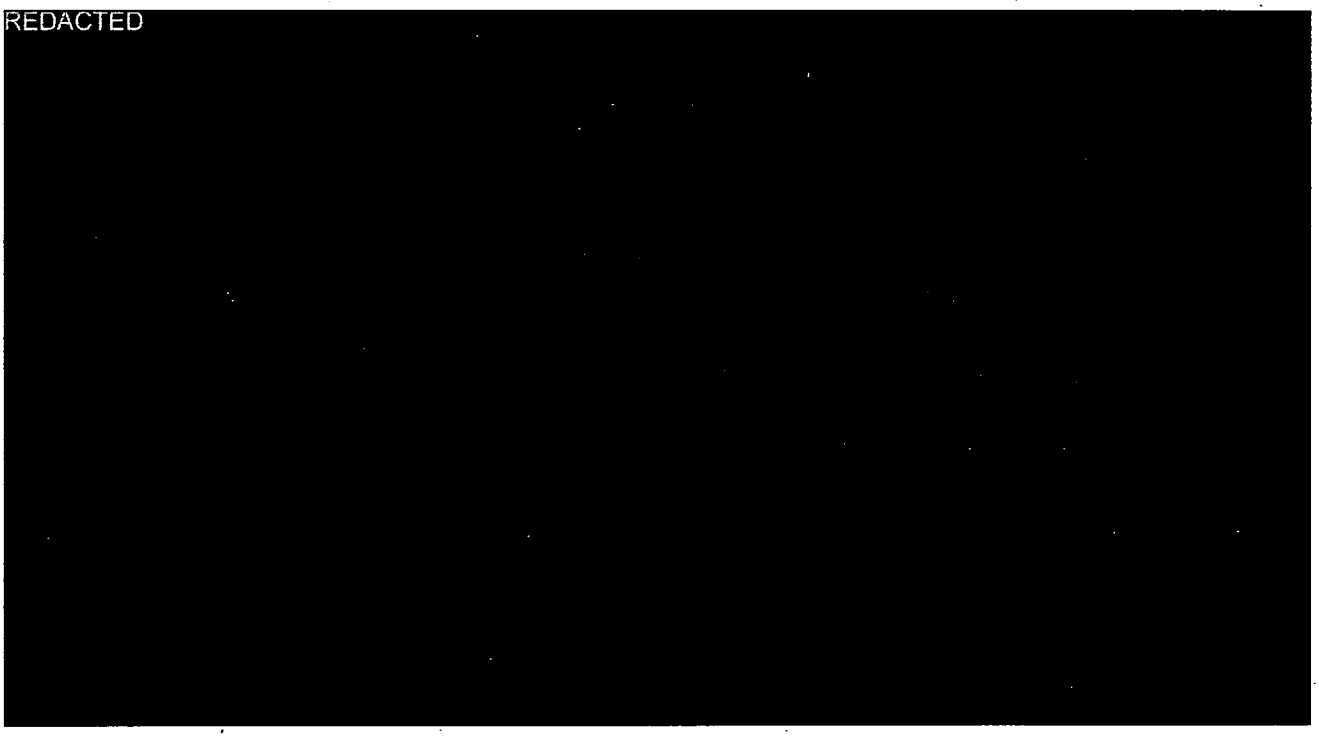
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NEW GENERATION SITING STUDY - 2011

DUKE ENERGY, CAROLINAS

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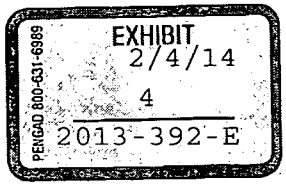

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EXECUTIVE SUMMARY

The Duke Energy Carolinas 2011 Integrated Resource Plan (IRP) identified a need for approximately 650 MW of combustion turbine generation in the 2016 – 2017 time frame. This study was commissioned to identify potential sites for new simple cycle and combined cycle generation in this time frame. Current modeling indicates that there will be a total need for 900 - 1200 MW by 2018.

Twelve sites including brown field, green field, Duke-owned, and non-Duke-owned sites were identified for study based on previous siting studies. Information was gathered on all sites and evaluated based on agreed upon criteria by the evaluation team.

Existing Duke Energy, Carolinas generation sites provide the best opportunities to plan, permit, engineer and construct in a relatively short time frame. Based on the information gathered in this phase of the study Lee is clearly the best site for combined cycle generation, however there may be water constraints especially if he existing station remains in service. The Lee site provides optionality over all other brown field sites considered in that the space available at Lee affords the opportunity to develop up to 1200 MW of generation and could be phased in simple cycle and combined cycle combinations.

Should simple cycle be preferred, Rockingham and Lincoln are good options for large scale generation. An alternate strategy could be employed where simple cycle generation is distributed throughout the system in 200 MW blocks which could include Buck, Riverbend and Buzzard Roost. Additional study will be required to determine the best simple cycle site.

I. SCOPE OF STUDY

The study was commissioned to initiate site selection for nominal 650 MW combined cycle and 650 MW simple cycle combustion turbine plants for Duke Energy, Carolinas. This scope of the study included:

- Identification of candidates sites
- Development of site selection evaluation criteria.
- Collection and documentation of criteria data for each candidate site.
- Site mapping on aerial photography showing existing facilities, potential power plant location, relevant utility infrastructure and land ownership.
- Recommendations for consideration of each site for further study.

II. BACKGROUND

In March of 2005, a Duke Power Siting Team completed a comprehensive New Generation Siting Study which provided the basis for the selection of the Cliffside site for the installation of new base load coal generation. This study also served as the basis for a combustion turbine combined cycle siting analysis in 2007 that led to the selection of Buck and Dan River for new intermediate combustion turbine combined cycle plants. In 2008 a new study effort resulted in the selection of Rockingham as the site for new simple cycle generation. This project was subsequently cancelled.

The Duke Energy Carolinas 2011 Integrated Resource Plan (IRP) identified the need for either natural gas fired simple cycle or combined cycle generation in the 2016-2017 time frame. This study is the first phase in the site selection process to address that need. Much of the work from the 2005 New Generation Siting Study served as basis for this study.

III. EVALUATION CRITERIA

Evaluation criteria were developed from past siting studies and updated with input from the siting study team.

Land Availability

Land availability is a critical siting issue as existing Duke owned property is most preferred and properties not owned by Duke and currently under multiple ownerships is least preferred.

Cultural and Land Use

Preferred sites will have minimal cultural, archeological, historical and population impacts. The specific data collected to evaluate this criterion are:

- Town within one (1) mile
- Population within one (1) mile
- Public lands within one (1) mile
- Compatibility with Land Use Plan
- Zoning Constraints
- Number of National Register Historical Sites within two (2) kilometer perimeter of site
- Archeological Resources
- Sensitive Species

Gas Availability

Available natural gas supply is critical to siting natural gas fired generation. The specific data collected to evaluate this criterion are:

- Distance to Pipeline
- Accessibility to Pipeline
- Operating Condition of Pipeline
- Multiple Pipelines Available
- Local Distribution Company (LDC) impacts

Water Availability

Water available in sufficient quantities for cooling tower makeup is necessary for efficient combined cycle generation. It is less critical for simple cycle facilities but sufficient water for combustor water injection to allow for dual fuel capability is strongly preferred. In addition the ability to revise or develop a new NPDES permit for discharge is strongly preferred over zero liquid discharge from a cost and efficiency standpoint. The specific data collected to evaluate this criterion are:

- Public water availability
- Well Water availability
- River Access
- Distance to River
- Ease of wastewater permitting

Transmission

Transmission considerations include the cost of tying into existing transmission, avoidance of transmission congestion and the benefit to the stability of the existing transmission system. At this stage of the siting study, it was determined to limit the transmission study effort, so information was collected based on current knowledge of the sites and the transmission systems.

Ease of Air Permitting

The ability to offset emissions to avoid Prevention of Significant Deterioration (PSD) and New Source Review (NSR) significantly benefits the permitting process, resulting in approximately a one-year reduction in the permitting duration.

Ozone non-attainment areas can significantly add to the cost of simple cycle generation because a hot SCR may be required.

Proposed MACT legislation may allow for a one-year extension of existing coal plants should new generation be built on the same site. This could provide a cost benefit for existing coal plant sites planned for shutdown in the 2016 – 2017 time frame.

Additional information collected for air permitting consideration include proximity to Class I Areas, adequate space for fence line modeling and airspace within one (1) mile radius.

Constructability

Constructability aspects considered include:

- Land available for permanent plant location
- Land available for laydown and parking
- Potential soil issues
- Rail availability for major equipment delivery
- Heavy Haul Road
- Terrain impact on cut and fill and site work.

Proximity to Existing Duke Facilities

Plants co-located on existing plant sites offer the benefit for potential resource sharing.

Time Constraints

This study considers new generation to achieve Commercial Operation in the 2016 – 2017 time frame. This time frame may eliminate some existing coal plant sites that are currently planned for shutdown in 2015 if there is not enough land available for the new plant site including with laydown and parking.

IV. SITES STUDIED

The sites listed below were considered in this siting study. All of these sites have been considered in previous siting studies. The site identification used in previous studies is shown in parenthesis. All sites are shown geographically relative to the main gas and transmission lines in Figure IV-1.

- Rockingham County
- Buck (NC-8-2)
- Dan River (NC-11)
- Lee (SC-1)
- Riverbend (NC-5)
- Allen
- Lincoln
- Mill Creek Plantation
- Perkins (NC-7-3)
- NCEMC (NC- 7-1)
- Cherokee County (SC-6)
- Chester County

Buzzard Roost was not considered in this study because it has been evaluated in the past as a poor site for large scale generation due to its remote location, limited transmission infrastructure and distance from the main Transco gas line.

V. SITE EVALUATION

V.1 Rockingham County

Description

Rockingham County is an existing Duke Energy, Carolinas simple cycle site located on NC-65, approximately 7 miles west of Reidsville. The site currently has five (5) Westinghouse 501F dual fuel combustion turbines. A new black start emergency diesel generator for the northern region is currently being commissioned at the site.

This site was selected in the 2008 Site Selection Study for a 640 MW simple cycle site. The land adjacent to the existing site was purchased for the new installation. The project progressed to the point of a Preliminary CPCN but was subsequently cancelled. An aerial photograph of the site showing the existing generation along with an overlay of the planned additional simple cycle generation is shown in Figure V-1.

Evaluation

Information collected for the evaluation is presented in Table V-1.

This site was demonstrated to be the best selection for simple cycle in the 2008 study. Land is available for permanent facilities as well as laydown and parking. There are no significant cultural/land use limitations. Heavy haul would be via road from the nearest rail siting but there was precedence from the original construction of the existing site. Being co-located with an existing Duke Energy site provides benefits in shared services.

From a transmission standpoint, this site benefits the northern region voltage collapse issue but would likely dictate significant costs in transmission upgrades.

The county has been designated as attainment for ozone by the North Carolina but must be approved by the EPA. If not approved it could potentially be a significant capital and operating cost issue for simple cycle due to LAER requirement leading to hot SCR on simple cycle. The Transco main gas line passes through the site.

The site is not a candidate for combined cycle generation due to lack of river water supply and space constraints.

Recommendation

Despite negative factors of transmission costs and possible LAER requirement, Rockingham provides sufficient benefits to be considered for new simple cycle generation in the 2016 – 2017 time frame.

V.2 Buck (NC-8-2)

Description

Buck is an existing Duke Energy, Carolinas coal plant site and combined cycle site located in Rowan County approximately 6 miles northeast of downtown Salisbury. Units 5 and 6 at the existing coal plant are planned for shutdown at the end of 2014. The combined cycle site went commercial in the fall of 2012.

This site was selected in the 2007 Site Selection Study for a 620 MW combined cycle site which subsequently came to fruition. An aerial photograph of the site showing the existing generation along with an overlay of potential blocks for combined cycle and simple cycle generation are shown in Figures V-2.1 and V-2.2.

Evaluation

Information collected for the evaluation is presented in Table V-2.

The best location for new generation at Buck is in the main laydown yard for the combined cycle plant construction, east of the combined cycle site. As can be seen in Figures V-2.1 and V-2.2, the blocks required for either simple cycle or combined cycle exceed the available land in this area and infringe on the heron rookery buffer zone. The power block layouts could be adjusted to use some additional land south of the proposed location in the area of the existing fuel oil storage tank and fuel oil unloading area. It should be noted that these areas have a high potential for soil contamination which would likely add to the cost and schedule of the project. The existing fuel oil tank could be used for fuel oil for a new dual fuel simple cycle plant.

Space is limited for new laydown for a new combined cycle plant until Units 5 and 6 are shutdown. At that time the coal pile area could potentially be used for laydown. The parking area for the combined cycle construction could be used for new construction, however, it is somewhat remote from the proposed power block site and the high voltage transmission in the space makes it less than ideal for laydown requiring crane lifts. There may be adequate laydown and parking for addition of simple cycle generation prior to shutting down the coal units by utilizing the old combustion turbine area as well as the laydown area at the plant entrance.

The site location would make the tie-in to the existing switchyard challenging without taking up significantly more space. The additional generation could also dictate significant upgrades to the transmission system.

The main Transco gas line is 9 miles away. The addition of another supply line would be a significant cost. There may be alternatives to lessen the impact through addition of a compression station at the site. Either option will exacerbate the space and layout issues prior to the shutdown of Units 5 and 6.

The site will likely be non-attainment for ozone for the Charlotte area which could be a significant capital and operating cost issue for simple cycle due to LAER requirement leading to hot SCR on simple cycle.

The Yadkin River provides an adequate source for makeup water and should not pose any significant issues for a revised NPDES for discharge.

Being co-located with an existing Duke Energy site provides benefits in shared services. From a transmission standpoint, this site benefits the northern region voltage collapse issue but would likely dictate significant costs in transmission upgrades.

Recommendation

Buck is not a good candidate for 650 MW simple cycle or combined cycle generation in the 2016 – 2017 time frame. It may be a candidate for smaller simple cycle generation in that time frame. After the shutdown of Units 5 and 6 there may be more opportunities to develop the site for additional power generation.

V.3 Dan River (NC-11)

Description

Dan River is an existing Duke Energy, Carolinas coal plant site with a new combined cycle plant being constructed for commercial operation in 2012. The site is located in the city of Eden, North Carolina in Rockingham County. The coal plant consisting of three units is scheduled to be shut down in the spring of 2012. Units 1 and 2 emissions were used for PSD avoidance netting for the new combined cycle plant.

This site was selected in the 2007 Site Selection Study for a 620 MW combined cycle site which subsequently came to fruition. An aerial photograph of the site showing the existing generation along with an overlay of potential blocks for combined cycle and simple cycle generation are shown in Figures V-3.1 and V-3.2.

Evaluation

Information collected for the evaluation is presented in Table V-3.

The best location for new generation at Dan River is in the construction warehouse, laydown yard and parking area for the combined cycle plant construction, north of the combined cycle site currently under construction. This terrain in this area falls off to the east and the south so significant fill may be required. The area of the existing coal pile and old combustion turbine units was also considered, however, space is limited in this area, experience has shown that there could be significant soil contamination, and the coal pile sits on rock which could make construction of undergrounds extremely challenging.

Laydown and parking could be made available with the use of the combined cycle laydown on the east ash landfill as well potential development of laydown areas on the west ash landfill and the existing coal pile area. There is additional contiguous land available to the east of the site which is currently includes a large warehouse/industrial complex which is currently for lease.

The site location would make the tie-in to the existing switchyard challenging without taking up significantly more space. The additional generation could also dictate significant upgrades to the transmission system. It may require a tie to the 230 kV system as opposed to the 100 kV system that the new combined cycle plant is tied. The location does benefit the northern region voltage collapse issue.

The main Transco gas line is 3 miles away the addition of another supply line would be a moderate cost. There may be alternatives to lessen the impact through addition of a compression station at the site.

The county has been designated as attainment for ozone by the North Carolina but must be approved by the EPA. If not approved it could potentially be a significant capital and operating cost issue for simple cycle due to LAER requirement leading to hot SCR on simple cycle. The Transco main gas line passes through the site.

The Dan River provides an adequate source for makeup water and should not pose any significant issues for a revised NPDES for discharge.

Being co-located with an existing Duke Energy site provides benefits in shared services.

Recommendation

Although there are challenges that may drive capital costs beyond acceptable levels, at this time there are no fatal flaws that would dictate that Dan River is not a candidate for 650 MW simple cycle or combined cycle generation. Therefore it should be considered for future study.

V.4 Lee (SC-1)

Description

Lee is an existing Duke Energy, Carolinas coal plant site located in Anderson County South Carolina approximately 2.5 miles from Williamston, South Carolina. The coal plant consisting of three units is scheduled to be converted to natural gas firing. The site also contains two simple cycle gas-fired LM6000 unit designed as backup for the Oconee Nuclear Station.

This site has been identified in previous studies as an ideal site for new generation but was not selected due to the need for voltage support in the northern region as well as a desire to save the Lee site for large scale generation in the future. An aerial photograph of the site showing the existing generation along with an overlay of potential block for combined cycle generation is shown in Figures V-4.

Evaluation

Information collected for the evaluation is presented in Table V-4.

The best location for new generation at Lee is south of the plant entrance road. This area is convenient to the main Transco gas line as well as the Broad River.

Ample laydown and parking could be made available in the same area as well as north of the plant entrance road.

The site is conveniently located to the 100 kV transmission system on site and the 500 kV system within in miles of the site. A tie to the 500 kV system is preferable for long-term large scale generation and would likely require minimal transmission system upgrades but could have a significant substation and tie-in cost.

The main Transco gas line runs south of the site approximately one (1) miles away.

Rail service is provided on site by CSX.

Currently the South Carolina Department of Health and Environmental Control (DHEC) plans to propose Anderson County as attainment for ozone but there is some risk that the EPA may not approve. If the site is non-attainment for ozone there could be a significant capital and operating cost issue for simple cycle due to LAER requirement leading to hot SCR on simple cycle.

The Saluda River may provide an adequate source for makeup water but poses challenges especially if the existing station remains in operation. There should not be any significant issues for a revised or new NPDES for discharge.

Recommendation

The Lee site offers flexibility for large scale combustion turbine based generation in simple cycle, combined cycle or phased simple cycle to combined cycle configurations. Therefore it should be considered for future study for both simple cycle and combined cycle. The site requires further study to evaluate the water supply issue as well as transmission right-of-way to the 525 kV system.

V.5 Riverbend (NC-5)

Description

Riverbend is an existing Duke Energy, Carolinas coal plant site located in Gaston County North Carolina on the Catawba River. The coal plant is scheduled to be shut down at the end of 2014. The site also contains old simple cycle peaking units.

This site has not been strongly considered in previous studies because of its proximity to Charlotte and the potential opposition from the residential areas surrounding the plant. Due to concerns about the loss of the existing generation from the plant's coal units impact on the transmission system there was renewed interest in adding new generation. In 2010 an internal study determined that the location of the plant would not be a fatal flaw to adding new generation but that the actual quantifiable benefit to the transmission system is relatively small.

An aerial photograph of the site showing the existing generation along with an overlay of two potential block options for combined cycle generation is shown in Figures V-5.

Evaluation

Information collected for the evaluation is presented in Table V-5.

Until the existing coal plant is retired the only available location for new generation at Riverbend is east of the existing ash basin. This area abuts against property owned by Mountain Island II LLC to the east which is currently under consideration for a new charter school site. Vehicle access, laydown and parking would also be limited prior to the coal plant retirement.

As an alternate after the coal plant is retired, the existing coal pile area could potentially be used for a new simple cycle or combined cycle site. Existing coal handling equipment would require demolition. This location requires a fair amount of site work and demolition but has the following advantages:

- Proximity to existing intake canal.
- Proximity to existing switchyards.
- Construction traffic would not pass Stonewater Bay subdivision.
- Less construction and commissioning noise in residential areas.
- Existing turbine floor could be used for indoor storage.
- Existing administrative offices could be used for construction offices
- Ash basin could be closed and covered as planned and used as laydown.
- Space east of ash basins is available for additional laydown.
- Area north of intake canal could be leased or purchased for parking or laydown.

The new plant would tie into the existing 100 kV system on site which would be a benefit to the Charlotte load pocket. Minimal upgrades would be required with the exception of overdutied breakers in the region.

The main Transco gas line is 6 miles away and a PSNC lateral runs through to the Riverbend site. The existing lateral does not have sufficient capacity to serve 650 MW of new generation at the site.

The timing of the permitting relative to the retirement of the existing coal plant is critical to PSD avoidance. Declining capacity factors impact the highest two of five year baseline look back period. The site is non-attainment for ozone which could be a significant capital and operating cost issue for simple cycle due to LAER requirement leading to hot SCR on simple cycle.

The Catawba River provides adequate source for makeup water and should not pose any significant issues for a revised NPDES for discharge.

The site's location near the Lincoln CT site provides benefits in shared services.

Recommendation

The best simple cycle configuration may be smaller aeroderivitive units that can provide the benefit of relatively low heat rate relative to most Duke Energy simple cycle units and be more applicable to SCR controls due to lower exhaust gas temperatures than large frame gas turbines.

Application of combined cycle will be largely dependent on the timing of the shutdown of the existing coal plant for space availability and emission netting purposes.

A significant amount of additional study is required to determine if new generation can be sited on the Riverbend site. The study should include evaluation of community acceptance, incorporation into retirement of existing coal-fired generation, soil and underground utility studies, and cost estimate to prepare the site for new generation.

V.6 Allen

Description

Allen is an existing Duke Energy, Carolinas coal plant site located in Gaston County North Carolina on the Catawba River.

This site has not been strongly considered in previous studies because of the lack of existing natural gas infrastructure and the distance and route to the main Transco line relative to other potential Duke brownfield sites.

An aerial photograph of the site showing the existing generation along with an overlay of potential block for combined cycle generation is shown in Figures V-6.

Evaluation

Information collected for the evaluation is presented in Table V-6.

The most suitable location for new generation at Allen is south of the existing plant entrance road. This area would require significant site work to deal with existing ash and spoils storage near the area. Additional area is available on the south side of the entrance road but several high voltage transmission lines cross the area. The area could potentially be used for parking and laydown. Other developable areas are available on the far south end of the Duke property and on the west side of South Point Road (State Highway 273). These areas could be used for laydown but are not optimal due proximity and access.

The new plant could tie into the existing 100 kV, 230 kV, or 525 kV systems on site which would benefit to the Charlotte load pocket. The cost impact of the tie-in is unknown.

The main Transco gas line is 13 miles away and right-of-way access may be difficult.

The Catawba River provides adequate source for makeup water and should not pose any significant issues for a revised NPDES for discharge.

Recommendation

Due to the potential difficulties in air permitting and natural gas supply along with the continued viability of the existing coal plant, Allen is not a good candidate for new gas generation in this decade.

V.7 Lincoln (Simple Cycle Only)

Description

Lincoln is an existing Duke Energy, Carolinas simple cycle gas turbine site consisting of 16 dual fuel fired General Electric 7EA combustion turbines.

Lincoln was evaluated in the 2008 Simple Cycle siting study but was not selected because it would not benefit the northern region.

An aerial photograph of the site showing the existing generation along with an overlay of potential block for combined cycle generation is shown in Figures V-7.

Evaluation

Information collected for the evaluation is presented in Table V-7.

There is ample land available for additional simple cycle generation on site. The best location is probably south of the existing site and north of the new Lincoln County water treatment plant.

The new plant would tie into the existing 230 kV system on site which would be a benefit to the Charlotte load pocket. The previous simple cycle study indicated that transmission upgrades costs could be significant.

The main Transco gas line passes just south of the site and provides excellent accessibility

The Lincoln County water treatment facility provides opportunities for water supply and wastewater water discharge.

The site's location provides benefits in shared services as well as potentially sharing of the existing administration building facilities.

Recommendation

Lincoln should be considered for additional simple cycle generation in the future.

V.8 Perkins/Mill Creek Plantation (NC-7-3, NC- 7-2)

Description

Perkins was originally developed as a potential nuclear site but was cancelled in the early 1980s. Mill Creek Plantation is adjacent to the Perkins site on the south side of the Yadkin River. Due to being Greenfield sites and their proximity to each other these sites carry many similar characteristics.

An aerial photograph of each site showing with an overlay of potential block for combined cycle generation is shown in Figures V-8-1 and V-8-2.

Evaluation

Information collected for the evaluation is presented in Table V-8-1 and Table V-8-2.

Both sites have more than ample space for new generation and associated construction facilities including laydown and parking.

Perkins and Mill Creek Plantation both pose accessibility challenges for electric transmission. Perkins would likely tie into 230 kV to the north of the site and Mill Creek Plantation could tie to either 100 kV or 230 kV to the east of the site. Both sites were evaluated poorly for transmission accessibility in the 2007 Simple Cycle Siting Study.

Both sites have relatively good access to natural gas although Mill Creek Plantation is preferred because a river crossing will not be required.

As with all Greenfield sites there is no opportunity for PSD avoidance. North Carolina DAQ has proposed by Davie and Davidson County as Attainment for ozone but the EPA must approve.

The Yadkin River provides adequate source for makeup water and should not pose any significant issues for a revised NPDES for discharge.

These sites' locations are relatively close to Buck and may provide some benefits in shared services.

Recommendation

Both Perkins and Mill Creek provide promise for future natural gas generation, however, in the 2016 – 2017 time frame, green field sites will not likely be cost competitive with existing brown field sites.

V.9 NCEMC (NC-7-1)

Description

This site located 6.5 miles northeast of Lexington, NC is owned by the North Carolina Electric Membership Corporation which has its own plans for a facility on the site. This site was considered in the Combined Cycle Site Selection Study in 2007 and the Simple Cycle Site Selection Study in 2008. In both cases it was eliminated from consideration mainly due to not being Duke owned.

An aerial photograph of the site with an overlay of potential block for combined cycle generation is shown in Figures V-9.

Evaluation

Information collected for the evaluation is presented in Table V-9.

The site is an excellent location for new combustion turbine generating capacity.

Duke 100 kV and 230 kV transmission runs through the site. The main Transco gas line runs adjacent to the site and is readily accessible. Right-of-way for a new water line from the Yadkin River 1.45 miles away is not optimal but would probably not pose a major obstacle.

As with all Greenfield sites there is no opportunity for PSD avoidance. North Carolina DAQ has proposed by Davie and Davidson County as Attainment for ozone but the EPA must approve.

The Yadkin River provides adequate source for makeup water and should not pose any significant issues for a revised NPDES for discharge.

These sites' locations are relatively close to Buck and may provide some benefits in shared services.

Recommendation

The NCEMC site is an excellent green field site for future natural gas generation, however, it is not owned by Duke and may be difficult to procure for generation in the 2016 – 2017 time frame.

V.10 Cherokee County (SC-6)

Description

The Cherokee County Site is located approximately 11 miles east of Spartanburg, SC and 8 miles southwest of Gaffney, SC. Although the site is not owned by Duke Energy, it has ample space for a new generating facility as well as reasonably good access to electric, gas, and water.

An aerial photograph of the site with an overlay of potential block for combined cycle generation is shown in Figures V-10.

Evaluation

Information collected for the evaluation is presented in Table V-10.

Duke 230 kV transmission passes directly through the site. Although the transmission impact is unclear it was judged in the 2008 Simple Cycle Siting Study as requiring minimal upgrades.

The main Transco gas line also passes through the site.

As with all Greenfield sites there is no opportunity for PSD avoidance. South Carolina DHEC has proposed Cherokee County as Attainment for ozone but the EPA must approve. There is some risk of non-attainment for the broader Upstate South Carolina region. This designation will only be a minor impact for combined cycle generation but could be significant for simple cycle generation.

The Pacolet River is 2.9 miles from the site and should be an adequate source for makeup water and should not pose any significant issues for a revised NPDES for discharge other than costs due to the distance.

The site is relatively close to the Mill Creek CT site which provides benefits in shared services.

Recommendation

This site has good potential for future generation but is not recommended in the 2016 – 2017 time frame due to acquisition timing, proximity to the planned Lee Nuclear Station, and inherent disadvantages of green field sites as compared to brown field sites with existing infrastructure.

V.11 Chester County (SC-8)

Description

The Chester County site is a green field site on SC Highway 72, southwest of the town of Chester in Chester County, SC. The site is owned by Duke Energy and part of it is currently used for biomass crops.

An aerial photograph of the site showing the existing generation along with an overlay of potential block for combined cycle generation is shown in Figures V-11.

Evaluation

Information collected for the evaluation is presented in Table V-11.

The 2291 acre site is relatively hilly but has more than ample space for new gas fired generation. The site is adjacent to the CSX mainline between Chester and Carlisle, SC. The Norfolk Southern mainline from Charlotte, NC to Columbia, SC is approximately 8 miles east of the site. The rail lines provide competition for heavy transportation to the site but rail to heavy haul transport unloading locations would need to be studied.

The new plant would tie into the 230 kV system between the Newport and Parr Tie Stations, approximately 4.5 miles from the site.

The main Transco gas line is 30 miles away but a Carolina Gas Transmission (CGT) lateral runs within 5 miles to the site. The existing lateral would have to be upgraded to provide sufficient capacity to serve the site. The cost of transmission could add about $0.20 to the gas price

As with all Greenfield sites there is no opportunity for PSD avoidance. South Carolina DHEC has proposed Chester County as Attainment for ozone but the EPA must approve. There is some risk of non-attainment for the broader Upstate South Carolina region. This designation will only be a minor impact for combined cycle generation but could be significant for simple cycle generation.

The Chester facility would withdraw water from a stretch of the Broad River encompassed by the Sumter National Forest. It was reported in the 2005 New Generation Siting Study that the river should have adequate flow but withdrawal and discharge to the river would likely prompt intervention from the Forest Service and the U.S. Fish and Wildlife Service.

The site's location does not provide any clear benefits in shared services.

Recommendation

The Chester County site has excellent potential but challenges with site development and water supply would make it difficult to execute a project in the 2016 - 2017 time frame.

VI. RESULTS AND CONCLUSIONS

Existing Duke Energy, Carolinas generation sites provide the best opportunities to plan, permit, engineer and construct in a relatively short time frame. Based on the information gathered in this phase of the study Lee appears to be the best site for combined cycle generation but requires additional study for water supply and transmission right-of-way.

Should simple cycle be preferred, Rockingham and Lincoln are the best options. Lee could also be developed as a simple cycle site with ultimate conversion to combined cycle. An alternate strategy could be employed where simple cycle generation is distributed throughout the system in 200 MW blocks which could include Buck, Riverbend and Buzzard Roost. If the IRP results determines that simple cycle is preferred additional study will be required.

Transmission interconnect studies have not been initiated on any of the sites studied. After the results of this siting study are reviewed with Duke IRP Group and input obtained on technology and schedule, Interconnect Studies should be initiated for the recommended sites.

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TABLE V-1: ROCKINGHAM COUNTY DATA

Site	Rockingham County (SC Only)
Criteria/Constraint	
Land Availability	
Duke Owned	Yes
Multiple Owners	No
Potential Plant Location	Adjacent to existing site
Potential Laydown Area	On site
Potential Soil Issues	No known issues
Cultural/Land Use	
Town within 1 mile	No (7 miles from Reidsville)
Population within 1 mile	267
Public Lands within 1 mile	no
Incompatible with Land Use Plan	Designated as Industrial
Zoning Contraints	HI &RA
Number of National Register of Historic Sites within 2 km of site perimeter	0
Sensitive Species	none
Gas Availability	
Distance to Pipeline	On site
Accessibility to Pipeline	Excellent - New metering/reducing station required.
Operating Condition of Pipeline	Good
Multiple Pipelines Available	No
LDC Impacts	Average
Water Availability	
Public Water	Municipal water - Piedmont Water
Well Water	No
River Access (for Combined Cycle)	No river access
Ease of Wastewater Permitting	Minimal for simple cycle
Transmission Availability	
Distance to Transmission	On site 230 kV
Accessibility to Transmission	Significant transmission upgrades expected
Transmission Benefit	Benefits northern region voltage collapse issue.
Ease of Air Permitting	
PSD/NSR Avoidance (BACT/LAER, Modeling and Time)	No - Significant issue for simple cycle if area is non-attainment. (LAER requirement)
Non-attainment area	NC has recommended County as Attainment for all pollutants. EPA draft response expected in December 2011.
Proximity to Class I Areas	Yes
Adequate Space (fenceline modeling issues)	Yes
Airspace within 1 mile	Yes, small private airport within one mile.
Potential Benefit for MACT 1-Year Extension	No.
Constructability	
Rail Availability	No
Heavy Haul (Road Type)	State
Traffic Flow/Community Impact	Low
Terrain/Cut&Fill/Sitework	Low
Proximity to existing Duke Facilities (shared staffing)	Existing simple cycle plant on site.
Time Constraints	None

TABLE V-2: BUCK (NC 8-2) DATA

Site	Buck (NC-8-2)
Criteria/Constraint	
Land Availability	
Duke Owned	Yes
Multiple Owners	No
Potential Plant Location	CTCC laydown area
Potential Laydown Area	Fuel Oil or Coal Pile
Potential Soil Issues	Potential for some groundwater issues
Cultural/Land Use	
Town within 1 mile	no (6 miles NE of Salisbury)
Population within 1 mile	392
Public Lands within 1 mile	No
Incompatible with Land Use Plan	Designated as Industrial
Zoning Contraints	IND
Number of National Register of Historic Sites within 2 km of site perimeter	0
Sensitive Species	Piedmont Indigo Bush, Eastern Small-Footed Myotis, Wading Bird Colony
Gas Availability	
Distance to Pipeline	9 miles
Accessibility to Pipeline	Average
Operating Condition of Pipeline	Good
Multiple Pipelines Available	no
LDC Impacts	Average
Water Availability	
Public Water	No
Well Water	Yes
River Access (for Combined Cycle)	Yes - Yadkin River
Ease of Wastewater Permitting	Minimal but new discharge may be required due to planned retirement of coal plant.
Transmission Availability	
Distance to Transmission	On site 230 kV
Accessibility to Transmission	Significant transmission upgrades expected
Transmission Benefit	Benefits northern region voltage collapse issue.
Ease of Air Permitting	
PSD/NSR Avoidance (BACT/LAER, Modeling and Time)	Probable with retirement of Buck 5 & 6
Non-attainment area	Yes - Charlotte area ozone
Proximity to Class I Areas	Yes
Adequate Space (fenceline modeling issues)	Yes
Airspace within 1 mile	No
Potential Benefit for MACT 1-Year Extension	Yes
Constructability	
Rail Availability	Yes
Heavy Haul (Road Type)	County
Traffic Flow/Community Impact	Medium
Terrain/Cut&Fill/Sitework	Low
Proximity to existing Duke Facilities (shared staffing)	Existing combined cycle on site
Time Constraints	Preferred Mobilization after 2014 - Unit 5 & 6 shutdown would provide additional laydown and parking space.

TABLE V-3: DAN RIVER (NC-11) DATA

Site	Dan River (N-11)
Criteria/Constraint	
Land Availability	
Duke Owned	Yes
Multiple Owners	No
Potential Plant Location	Fuel Oil or Coal Pile
Potential Laydown Area	CTCC laydown
Potential Soil Issues	High potential for contaminated soil and rock will cause difficulty in undergrounds
Cultural/Land Use	
Town within 1 mile	yes (adjacent to Eden city limits)
Population within 1 mile	808
Public Lands within 1 mile	no
Incompatible with Land Use Plan	Designated as Industrial
Zoning Contraints	RA
Number of National Register of Historic Sites within 2 km of site perimeter	0
Sensitive Species	Roanoke hog sucker,green floater, bigeye jumprock
Gas Availability	
Distance to Pipeline	3 miles
Accessibility to Pipeline	Good
Operating Condition of Pipeline	Good
Multiple Pipelines Available	yes
LDC Impacts	Average
Water Availability	
Public Water	Municipal Water - City of Eden
Well Water	No
River Access (for Combined Cycle)	Yes - Dan River
Ease of Wastewater Permitting	Minimal
Transmission Availability	
Distance to Transmission	On site 100 kV
Accessibility to Transmission	Significant transmission upgrades expected
Transmission Benefit	Benefits northern region voltage collapse issue.
Ease of Air Permitting	
PSD/NSR Avoidance (BACT/LAER, Modeling and Time)	Possible with retirement of Dan River 3 however, timing for netting may be challenging.
Non-attainment area	NC has recommended County as Attainment for all pollutants. EPA draft response expected in December 2011.
Proximity to Class I Areas	Yes
Adequate Space (fenceline modeling issues)	No
Airspace within 1 mile	No
Potential Benefit for MACT 1-Year Extension	No
Constructability	
Rail Availability	Yes
Heavy Haul (Road Type)	County
Traffic Flow/Community Impact	Medium
Terrain/Cut&Fill/Sitework	Medium
Proximity to existing Duke Facilities (shared staffing)	Existing combined cycle on site
Time Constraints	Preferred mobilization after 2012 - Complete Dan River CTCC

TABLE V-4: LEE (SC-1) DATA

Site	Lee (SC-1)
Criteria/Constraint	
Land Availability	
Duke Owned	Yes
Multiple Owners	No
Potential Plant Location	South of Lee Steam Plant
Potential Laydown Area	South of LSP between road & xmission
Potential Soil Issues	No known issues
Cultural/Land Use	
Town within 1 mile	no (2.5 miles from Williamston, SC)
Population within 1 mile	369
Public Lands within 1 mile	no
Incompatible with Land Use Plan	Designated as Residential - Agricultural
Zoning Contraints	R-D
Number of National Register of Historic Sites within 2 km of site perimeter	0
Sensitive Species	None
Gas Availability	
Distance to Pipeline	1 mile
Accessibility to Pipeline	Excellent
Operating Condition of Pipeline	Good
Multiple Pipelines Available	No
LDC Impacts	Average
Water Availability	
Public Water	Yes
Well Water	
River Access (for Combined Cycle)	Yes - Saluda River
Ease of Wastewater Permitting	Minimal but new discharge may be required due to planned retirement of coal plant.
Transmission Availability	
Distance to Transmission	On site 100 kV but access to 500 kV within 5 miles is desirable.
Accessibility to Transmission	Limited upgrades to 500 kV system except for overdutied breakers at ONS.
Transmission Benefit	Benefits 500kV system.
Ease of Air Permitting	
PSD/NSR Avoidance (BACT/LAER, Modeling and Time)	Possible with retirement of existing coal capacity. If planned gas conversion of coal units is permitted at low enough capacity may be able to net out of all but CO and VOC.
Non-attainment area	SC DHEC will propose Anderson County as attainment for ozone but EPA must approve. There is some risk of non-attainment for the broader Upstate SC region.
Proximity to Class I Areas	Yes
Adequate Space (fenceline modeling issues)	Yes
Airspace within 1 mile	Yes, small private airport within one mile.
Potential Benefit for MACT 1-Year Extension	No.
Constructability	
Rail Availability	Yes
Heavy Haul (Road Type)	County
Traffic Flow/Community Impact	Low
Terrain/Cut&Fill/Sitework	Low
Proximity to existing Duke Facilities (shared staffing)	May be existing staff if gas conversion of existing coal plant is executed.
Time Constraints	Netting ability limited by timing.

TABLE V-5: RIVERBEND (NC-5) DATA

Site	Riverbend (NC-5)
Criteria/Constraint	
Land Availability	
Duke Owned	Yes (additional land may be needed for buffer/parking/laydown
Multiple Owners	No
Potential Plant Location	East of Ash Basin
Potential Laydown Area	East of Ash Basin
Potential Soil Issues	Potential soft soil issues near lake
Cultural/Land Use	
Town within 1 mile	No (11.7 miles NE of Charlotte, NC)
Population within 1 mile	220
Public Lands within 1 mile	No
Incompatible with Land Use Plan	Designated as Industrial
Zoning Contraints	I-3 at existing plant, R-1 in undeveloped areas
Number of National Register of Historic Sites within 2 km of site perimeter	Holly Bend Site is 1.36 km from property line. NRHP listed.
Sensitive Species	Oldfield mouse, Basic mesic forest
Gas Availability	
Distance to Pipeline	5 miles
Accessibility to Pipeline	Good
Operating Condition of Pipeline	Good
Multiple Pipelines Available	No
LDC Impacts	Average
Water Availability	
Public Water	Yes - City of Belmont
Well Water	No
River Access (for Combined Cycle)	Yes - Catawba River
Ease of Wastewater Permitting	Minimal but new discharge may be required due to planned retirement of coal plant.
Transmission Availability	
Distance to Transmission	On -site
Accessibility to Transmission	Minimal impact on transmission system with exception of overdutied breakers in region.
	Benefit to Charlotte load pocket.
Ease of Air Permitting	
PSD/NSR Avoidance (BACT/LAER, Modeling and Time)	Timing of permitting relative to retirement of Unit 3 is critical to PSD avoidance.
Non-attainment area	Yes - Charlotte area ozone
Proximity to Class I Areas	Yes
Adequate Space (fenceline modeling issues)	Yes
Airspace within 1 mile	No
Constructability	
Rail Availability	Yes
Heavy Haul (Road Type)	County
Traffic Flow/Community Impact	Poor (Close residential)
Terrain/Cut&Fill/Sitework	Medium (clear and grub)
Proximity to existing Duke Facilities (shared staffing)	Near Lincoln CT Station
Time Constraints	Current plan to shut down at the end of 2014 may add to difficulty in meeting schedule.

TABLE V-6: ALLEN DATA

Site	Allen
Criteria/Constraint	
Land Availability	
Duke Owned	Yes
Multiple Owners	No
Potential Plant Location	South of Plant Allen entrance road
Potential Laydown Area	North of Plant Allen entrance road and
Potential Soil Issues	Ash and spoil material likely to cause extensive sitework.
Cultural/Land Use	
Town within 1 mile	no (4 miles south of Belmont, NC and 10 miles SE of Charlotte, NC)
Population within 1 mile	651
Public Lands within 1 mile	No
Incompatible with Land Use Plan	Designated as Industrial
Zoning Contraints	I-3 and R-1
Number of National Register of Historic Sites within 2 km of site perimeter	0
Sensitive Species	Atlantic Highfin Carpsucker
Gas Availability	
Distance to Pipeline	13 miles
Accessibility to Pipeline	Poor - No existing gas ROW
Operating Condition of Pipeline	Good
Multiple Pipelines Available	No
LDC Impacts	Average
Water Availability	
Public Water	Yes - City of Belmont
Well Water	No
River Access (for Combined Cycle)	Yes - Catawba River
Ease of Wastewater Permitting	Minimal
Transmission Availability	
Distance to Transmission	On-site
Accessibility to Transmission	Transmission impact unclear
	Depends on long term viability of coal plant.
Ease of Air Permitting	
PSD/NSR Avoidance (BACT/LAER, Modeling and Time)	Yes if one or more units are retired.
Non-attainment area	yes - Charlotte area ozone
Proximity to Class I Areas	Yes
Adequate Space (fenceline modeling issues)	Yes
Airspace within 1 mile	Yes - Airport is 2 miles but flight path over/near station.
Constructability	
Rail Availability	Yes
Heavy Haul (Road Type)	County
Traffic Flow/Community Impact	Average
Terrain/Cut&Fill/Sitework	May have significant soil contamination.
Proximity to existing Duke Facilities (shared staffing)	Only if coal units remain in service.
Time Constraints	Significant site work and gas lateral work required.

TABLE V-7: LINCOLN DATA (SIMPLE CYCLE ONLY)

Site	Lincoln (SC Only)
Criteria/Constraint	
Land Availability	
Duke Owned	Yes
Multiple Owners	No
Potential Plant Location	South of existing plant
Potential Laydown Area	South of existing plant
Potential Soil Issues	No known issues
Cultural/Land Use	
Town within 1 mile	no (2 miles west of Lowesville, NC
Population within 1 mile	514
Public Lands within 1 mile	no
Incompatible with Land Use Plan	Designated as Industrial in Future Land Use Plan
Zoning Contraints	I-G
Number of National Register of Historic Sites within 2 km of site perimeter	0
Sensitive Species	none
Gas Availability	
Distance to Pipeline	On site
Accessibility to Pipeline	Excellent
Operating Condition of Pipeline	Good
Multiple Pipelines Available	No
LDC Impacts	Average
Water Availability	
Public Water	Yes - Lincoln County
Well Water	Yes
River Access (for Combined Cycle)	No
Ease of Wastewater Permitting	Minimal - Lincoln County Waste Treatment adjacent to site.
Transmission Availability	
Distance to Transmission	On-Site
Accessibility to Transmission	Transmission impact unclear but 2007 study indicated high cost transmission upgrades
	Benefit to Charlotte Load pocket.
Ease of Air Permitting	
PSD/NSR Avoidance (BACT/LAER, Modeling and Time)	No
Non-attainment area	yes - Charlotte area ozone
Proximity to Class I Areas	Yes
Adequate Space (fenceline modeling issues)	Yes
Airspace within 1 mile	No
Constructability	
Rail Availability	No
Heavy Haul (Road Type)	County
Traffic Flow/Community Impact	Average
Terrain/Cut&Fill/Sitework	Minimal
Proximity to existing Duke Facilities (shared staffing)	Yes - Existing staff and Admin Bldg
Time Constraints	

TABLE V-8-1: PERKINS DATA

Site	Perkins (NC-7 -3)
Criteria/Constraint	
Land Availability	
Duke Owned	Yes
Multiple Owners	No
Potential Plant Location	Very large site - could be strategically located for best gas and transmission access.
Potential Laydown Area	Plentiful on site
Potential Soil Issues	No known issues
Cultural/Land Use	
Town within 1 mile	no (7 miles SE of Mocksville, NC)
Population within 1 mile	173
Public Lands within 1 mile	No
Incompatible with Land Use Plan	Designated as Rural/Residential
Zoning Contraints	R-A
Number of National Register of Historic Sites within 2 km of site perimeter	Coolemee 2 km from property line . NHRP Listed and National Landmark
Sensitive Species	Eastern small footed myotis, Spring Coralroot, Crested Coralroot, Dry mesic oak hickory forest, mesic mixed hardwood forest, Piedmont/low mountain alluvial forest, Piedmont mountain levee forest, Piedmont mountain bottomland forest
Gas Availability	
Distance to Pipeline	4 miles
Accessibility to Pipeline	Good
Operating Condition of Pipeline	Good
Multiple Pipelines Available	No
LDC Impacts	Average
Water Availability	
Public Water	No
Well Water	No
River Access (for Combined Cycle)	Yes - Yadkin River
Ease of Wastewater Permitting	New NPDES required
Transmission Availability	
Distance to Transmission	3 miles to 230 kV - Difficult access
Accessibility to Transmission	Transmission impact unclear
	Benefit to Northern Region voltage collapse issue
Ease of Air Permitting	
PSD/NSR Avoidance (BACT/LAER, Modeling and Time)	No
Non-attainment area	DAQ will propose area as attainment for ozone , but EPA must approve.
Proximity to Class I Areas	Yes
Adequate Space (fenceline modeling issues)	Yes
Airspace within 1 mile	No
Constructability	
Rail Availability	Not on site - approximately 10 miles to NS
Heavy Haul (Road Type)	County
Traffic Flow/Community Impact	Minimal impact
Terrain/Cut&Fill/Sitework	Greenfield - Significant sitework
Proximity to existing Duke Facilities (shared staffing)	Possible with Buck CC for support functions
Time Constraints	Greenfield - Significant development required.

TABLE V-8-2: MILL CREEK PLANTATION DATA

Site	Mill Creek Plantation
Criteria/Constraint	
Land Availability	
Duke Owned	Yes
Multiple Owners	No
Potential Plant Location	Very large site - could be strategically located for best gas and transmission access.
Potential Laydown Area	Plentiful on site
Potential Soil Issues	No known issues
Cultural/Land Use	
Town within 1 mile	no (9 miles west of Lexington, NC)
Population within 1 mile	398
Public Lands within 1 mile	No
Incompatible with Land Use Plan	Designated for a Utility
Zoning Contraints	RA-1 and RA-2
Number of National Register of Historic Sites within 2 km of site perimeter	Coolemee 0.42 km from property line . NHRP Listed and National Landmark
Sensitive Species	Creamy tick trefoil, Eastern small footed myotis, Robust Redhorse, Crested Coralroot, Dry mesic oak hickory forest, mesic mixed hardwood forest, Piedmont/low mountain alluvial forest, low elevation seep
Gas Availability	
Distance to Pipeline	2 miles
Accessibility to Pipeline	Good
Operating Condition of Pipeline	Good
Multiple Pipelines Available	No
LDC Impacts	Average
Water Availability	
Public Water	No
Well Water	No
River Access (for Combined Cycle)	Yes - Yadkin River
Ease of Wastewater Permitting	New NPDES required
Transmission Availability	
Distance to Transmission	3 miles to 100 kV and 230 kV - Difficult access
Accessibility to Transmission	Transmission impact unclear
	Benefit to Northern Region voltage collapse issue
Ease of Air Permitting	
PSD/NSR Avoidance (BACT/LAER, Modeling and Time)	No
Non-attainment area	DAQ will propose area as attainment for ozone , but EPA must approve.
Proximity to Class I Areas	Yes
Adequate Space (fenceline modeling issues)	Yes
Airspace within 1 mile	No
Constructability	
Rail Availability	Not on site - approximately 10 miles to NS
Heavy Haul (Road Type)	County
Traffic Flow/Community Impact	Minimal impact
Terrain/Cut&Fill/Sitework	Greenfield - Significant sitework
Proximity to existing Duke Facilities (shared staffing)	Possible with Buck CC for support functions
Time Constraints	Greenfield - Significant development required.

TABLE V-9: NCEMC (NC 7-1) DATA

Site	NCEMC (NC-7-1)
Criteria/Constraint	
Land Availability	
Duke Owned	No
Multiple Owners	No
Potential Plant Location	Large site - 438 acres
Potential Laydown Area	Plentiful
Potential Soil Issues	No known issues
Cultural/Land Use	
Town within 1 mile	no (6.5 miles NE of Lexington, NC)
Population within 1 mile	619
Public Lands within 1 mile	no
Incompatible with Land Use Plan	Designated for a Utility
Zoning Contraints	CU-HI
Number of National Register of Historic Sites within 2 km of site perimeter	0
Sensitive Species	Eastern small footed myotis
Gas Availability	
Distance to Pipeline	Less than 1 mile
Accessibility to Pipeline	Excellent
Operating Condition of Pipeline	Good
Multiple Pipelines Available	No
LDC Impacts	Average
Water Availability	
Public Water	No
Well Water	Unknown
River Access (for Combined Cycle)	1.45 miles to Yadkin River
Ease of Wastewater Permitting	New NPDES required - Could have ROW issues
Transmission Availability	
Distance to Transmission	100 kV and 230 kV pass through site
Accessibility to Transmission	Moderate impact
	Benefit to Northern Region voltage collapse issue
Ease of Air Permitting	
PSD/NSR Avoidance (BACT/LAER, Modeling and Time)	No
Non-attainment area	DAQ will propose area as attainment for ozone, but EPA must approve.
Proximity to Class I Areas	Yes
Adequate Space (fenceline modeling issues)	Yes
Airspace within 1 mile	No
Constructability	
Rail Availability	Not on site - approximately 6 miles to NS
Heavy Haul (Road Type)	County
Traffic Flow/Community Impact	Minimal impact
Terrain/Cut&Fill/Sitework	Greenfield however relatively flat farmland and good external tree buffer.
Proximity to existing Duke Facilities (shared staffing)	Possible with Buck CC for support functions
Time Constraints	Greenfield - Significant development required.

TABLE V-10: CHEROKEE COUNTY (SC-6) DATA

Site	Cherokee County (SC-6)
Criteria/Constraint	
Land Availability	
Duke Owned	No
Multiple Owners	Yes
Potential Plant Location	Large site - 532 acres
Potential Laydown Area	Plentiful
Potential Soil Issues	No known issues
Cultural/Land Use	
Town within 1 mile	no (11 miles east of Spartanburg, SC and 8 miles SW of Gaffney, SC)
Population within 1 mile	236
Public Lands within 1 mile	no
Incompatible with Land Use Plan	None
Zoning Contraints	None
Number of National Register of Historic Sites within 2 km of site perimeter	0
Sensitive Species	None
Gas Availability	
Distance to Pipeline	On site
Accessibility to Pipeline	Excellent
Operating Condition of Pipeline	Good
Multiple Pipelines Available	No
LDC Impacts	Average
Water Availability	
Public Water	No
Well Water	No
River Access (for Combined Cycle)	Pond on site - 2.9 miles to Pacolet River
Ease of Wastewater Permitting	New NPDES required - Could have ROW issues
Transmission Availability	
Distance to Transmission	230 kV passes through site
Accessibility to Transmission	Transmission impact unclear - Adjacent to Lee Nuclear site
Ease of Air Permitting	
PSD/NSR Avoidance (BACT/LAER, Modeling and Time)	No
Non-attainment area	SC DHEC will propose Cherokee County as attainment for ozone but EPA must approve. There is some risk of non-attainment for the broader Upstate SC region.
Proximity to Class I Areas	Yes
Adequate Space (fenceline modeling issues)	Yes
Airspace within 1 mile	No
Constructability	
Rail Availability	Local access to NS - adjacent to Lee Nuclear site.
Heavy Haul (Road Type)	County
Traffic Flow/Community Impact	Minimal Impact
Terrain/Cut&Fill/Sitework	Greenfield - Significant sitework
Proximity to existing Duke Facilities (shared staffing)	Possible with Mill Creek
Time Constraints	Greenfield - Significant development required.

TABLE V-11: CHESTER COUNTY (SC-8) DATA

Site	Chester County
Criteria/Constraint	
Land Availability	
Duke Owned	Yes
Multiple Owners	No
Potential Plant Location	Large site - 2291 acres
Potential Laydown Area	Plentiful
Potential Soil Issues	No known issues
Cultural/Land Use	
Town within 1 mile	no (9miles SW of Chester, SC)
Population within 1 mile	47
Public Lands within 1 mile	No
Incompatible with Land Use Plan	Site is located in an area designated as rural, Future Land use is Industrial.
Zoning Contraints	R-2
Number of National Register of Historic Sites within 2 km of site perimeter	0
Sensitive Species	Soft Groovebur
Gas Availability	
Distance to Pipeline	5 miles to Carolina Gas Transmission (CGT), 30 miles to Transco
Accessibility to Pipeline	Average
Operating Condition of Pipeline	Poor
Multiple Pipelines Available	No
LDC Impacts	Low
Water Availability	
Public Water	No
Well Water	
River Access (for Combined Cycle)	4 miles to Broad River
Ease of Wastewater Permitting	New NPDES required - Could have ROW issues
Transmission Availability	
Distance to Transmission	230 kV less than 1 mile
Accessibility to Transmission	Transmission impact unclear
Ease of Air Permitting	
PSD/NSR Avoidance (BACT/LAER, Modeling and Time)	No
Non-attainment area	SC DHEC will propose Chester County as attainment for ozone but EPA must approve.
Proximity to Class I Areas	Yes
Adequate Space (fenceline modeling issues)	No
Airspace within 1 mile	No
Constructability	
Rail Availability	CSX on site. NS nearby.
Heavy Haul (Road Type)	County
Traffic Flow/Community Impact	Minimal impact
Terrain/Cut&Fill/Sitework	Greenfield - Significant sitework
Proximity to existing Duke Facilities (shared staffing)	No
Time Constraints	Greenfield - Significant development required.

Draft Phase II Siting Matrix for Carolinas
800 MW Combined Cycle, 2017 COD

Major Category/ Criterion	Category/Criterion Weight	Criterion Composite Weight	Rating Criteria	Criteria Scores	Lee	Mill Creek	NCEMC	Perkins	White Oak	Weatherspoon
Transmission Impact	**20%**									
Distance To Interconnection from property line	25%	5.0%	Within 1 Mile 1 mile to 4 Miles Greater than 4 Miles	50 30 10	50	10	50	30	50	50
Cost of transmission upgrades	75%	15.0%	<$50M $50M-$100M > $100M	50 30 10	50	30	30	30	50	30
Weighted Category Score	**100%**	**20%**			**10.00**	**5.00**	**7.00**	**6.00**	**10.00**	**7.00**
Gas System Impact	**30%**									
Distance To Transco Interconnection	20%	6.0%	Within 2 Mile 2 Mile to 10 Miles Greater than 10 Miles	50 30 10	50	50	50	30	10	10
Estimated Unit Gas Cost from Fuels	80%	24.0%	< $0.30/MMBtu $0.30-$0.60/MMBtu > $0.60/MMBtu	50 30 10	50	50	50	50	30	10
Weighted Category Score	**100%**	**30%**			**15.00**	**15.00**	**15.00**	**13.80**	**7.80**	**3.00**
Water Supply/Discharge & Availability	**20%**									
Water Availability and Distance	50%	10.0%	High Probability of Water Available Moderate Probability of Water Availability Low Probability of Water Availability	50 30 10	50	50	30	30	30	50
Ease of Permitting	50%	10.0%	Low Risk Moderate Risk High Risk	50 30 10	50	30	30	30	50	50
Weighted Category Score	**100%**	**20%**			**10.00**	**8.00**	**6.00**	**6.00**	**8.00**	**10.00**
Air Permitting	**10%**									
Potential to Net Emissions	60%	6.0%	High Potential to Net All Emissions High Potential to Net Some Emissions Low Potential to Net Any Emissions	50 30 10	30	10	10	10	10	30
Nonattainment Status	10%	1.0%	In Attainment Area In Nonattainment Area	50 10	50	50	50	50	50	50
NAAQS Compliance Risk	30%	3.0%	Low Risk Moderate Risk High Risk	50 30 10	50	50	50	50	50	50
Weighted Category Score	**100%**	**10%**			**3.80**	**2.60**	**2.60**	**2.60**	**2.60**	**3.80**
Constructability	**10%**									
Zoning Status	25%	2.5%	Zoned for Power Plant Use Conditional Use Permit Required Not Zoned for Power Plant Use	50 30 10	50	10	10	10	10	30
Site Layout Constraints	25%	2.5%	No Significant Constraints Exist Moderate Constraints Exist Significant Constraints Exist	50 30 10	50	30	50	30	50	10
Noise / Visual Receptors	25%	2.5%	No Sensitive Receptors within 1/2 Mile Sensitive Receptors within 1/2 Mile	50 10	50	10	10	30	50	50
Site Ownership	25%	2.5%	Site is owned by DE Site is not owned byDE	50 10	50	50	10	50	50	50
Weighted Category Score	**100%**	**10%**			**5.00**	**2.50**	**2.00**	**3.00**	**4.00**	**3.50**
Other Environmental and Socioeconomic Factors	**10%**									
Opposition to build	25%	2.5%	Little Opposition Some risk of opposition Strong Opposition	50 30 10	50	30	30	30	30	50
Wetlands/Floodplains	25%	2.5%	No Significant Constraints Exist Moderate Constraints Exist Significant Constraints Exist	50 30 10	30	30	50	30	10	50
Cultural Resources	25%	2.5%	Limited Potential for CRs to be present Moderate Risk of CRs to be present High Risk of CRs to be present	50 30 10	50	10	30	10	50	50
Sensitive Species	25%	2.5%	Limited Risk of Impacting Sensitive Species Moderate Risk of Impacting Sensitive Species High Risk of Impacting Sensitive Species	50 30 10	50	10	30	10	30	50
Weighted Category Score	**100%**	**10%**			**4.50**	**2.00**	**3.50**	**2.00**	**3.00**	**5.00**
Total Composite Score		**100%**			**48.30**	**35.10**	**36.10**	**33.40**	**35.40**	**32.30**

Landseidel Direct Exhibit 3

2017 Duke Energy Carolinas Site Inventory Summary

800 Natural Gas Fired Combined Cycle

	Weatherspoon Plant (170 MW Retired Capacity)	Cape Fear Plant (323 MW Retired Capacity)	Robinson (Darlington) Plant (185 MW Coal Retired Capacity)	White Oak Site (Harris Plant Lands)	Davidson County Site NC-7-1	Buck (NC-8-2)	Dan River (N-11)	Lee (SC-1)	Lincoln	Mill Creek Plantation (NC-7 -2)*	Cherokee County (SC-6)
Site Description	Duke owned brownfield site in Robeson County, NC located on the Lumber River.	Duke owned brown field site in Chatham County, NC located on the Cape Fear River.	Duke owned brown field site at Robinson nuclear site in Darlington County, SC located on Lake Robinson.	Duke owned green field site at Harris nuclear site in Wake County, NC This site uses transmission capacity that might otherwise be used by Harris Unit 2	Former NCEMC site in Davidson County, NC located near the Yadkin River. The 438 ac site is not owned by Duke Energy.	Duke owned brownfield site on the Yadkin River in Rowan County, NC. Reportedly good for 2x1 but difficult for 3x1	Duke owned brown field site in Rockingham, NC on the Dan River.	Duke owned brown field site in Anderson County, SC located on the Saluda River	Duke owned brown field site in Lincoln County, NC located on Killian Creek.	Duke owned 1500 ac green field site located on the Yadkin River. (Upstream ofHigh Rock Lake) in Davie County, NC	
Transmission Access GREEN: <$40M Yellow: $40M - $80M RED: >$80M	Good for up to 700 MW (~$75 million per 200 MW increments up to ~600 MW additional) For 800 MW, assume upgrade for 1 200 MW increments for $75M YELLOW	Good for up to 400 MW (~$100 million per 200 MW increments up to ~600 MW additional) Centrally located For 800 MW, assume upgrade for 2 200 MW increments for $200M RED	Good for up to 200 MW ($100 million per 200 MW increments up to ~600 MW additional) For 800 MW, assume upgrade for 2 200 MW increments for $200M RED	Good for up to 1100 MW (~$100 million per 200 MW increments up to ~600 MW additional) Requires Nuclear to release Harris 2 from Interconnect Queue. For 800 MW, assume no upgrade costs. $0 GREEN	Site in Duke Energy service area—existing 230 kV & 100 kV lines cross site—upgrade requirement undetermined but is expected to be approximately $50M per Pierce/Piper Benefit to Northern Region voltage collapse issue YELLOW	On site 230 kV. Benefits northern region voltage collapse issue. Uncertain without study per OH Piper Suggested upper bound cost est: $60M If Buck selected, cost of upgrades needed to build at Mill Creek/Perkins will need to be evaluated and may be excessive YELLOW	On site 100 kV Significant transmission upgrades expected Benefits northern region voltage collapse issue. upgrade requirement undetermined RWPierce/OH Piper said 800 MW at DR is a bad idea. Would require rebuild of region between DR and Greensboro. RED	On site 100 kV but 500 kV within 5 miles Estimated cost per Oasis evaluation <$20M GREEN	100 kV Transmission on site. Approximately 4 miles to 500kV system. Cost of adding 800 MW at Lincoln undetermined but is expected to be approximately $40M per Pierce/Piper Benefit to Charlotte load pocket. YELLOW	3 miles to Tyro line (100 kV and 230 kV) and 4 miles to Marshall to Beckerdite line. Access difficulty uncertain, as well as existence of ROW for Perkins Nuclear Site. If no existing ROW, will require new transmission line be included in CPCN for plant. Upgrade requirement undetermined but is expected to be approximately $50M per Pierce/Piper Benefit to Northern Region voltage collapse issue If Mill Creek selected, cost of upgrades needed to build later at Buck will need to be evaluated and may be excessive YELLOW	230 kV passes thru site. RW Pierce estimated $50 M in 4/18/13 email . Near Lee Nuclear Station. YELLOW
Fuel Supply GREEN: <$0.30 Yellow: $0.31-$0.60 RED: >$0.61	Natural gas indicative 100% daily demand rate ~$0.75/MMBtu (~$38.9 MM/yr) Note: This rate was supplied by Piedmont 06/07/2012 and was for a 2x1 CC (~600 MW) ~133 miles to Transco. Connected to Piedmont Selma fuel oil terminal (~90 miles) RED	Natural gas indicative 100% daily demand rate ~$0.751/MMBtu (~$38.9 MM/yr) Note: This rate was supplied by PSNC on 02/14/2011 and was for a 2x1 CC (~600 MW) PB The rate for Cardinal was supplied by Transco on 04/02/2013 for a 3x1 CC (~ 1200 MW). ~122 miles to Transco. Not connected to existing P/L Selma fuel oil terminal (~60 miles) RED	Natural gas indicative 100% daily demand rate ~$0.751/MMBtu (~$38.9 MM/yr) CGT has not supplied any estimate for an 800 MW PB. ~130 miles to Transco. Connected to Carolina Gas Trans Charlotte fuel oil terminal (~80 miles) RED	Natural gas indicative 100% daily demand rate ~$0.532/MMBtu (~$27.6 MM/yr) Note: This rate was supplied by PSNC on 03/06/2013 and was for a 3x1 CC (~1200 MW). The rate for Cardinal was supplied by Transco on 04/02/2013 for a 3x1 CC (~1200 MW). ~105 miles to Transco. Not connected to existing P/L Selma fuel oil terminal (~50 miles) YELLOW	Excellent accessibility, good operating condition, average LDC impacts Natural gas indicative 100% daily demand rate ~$0.10/MMBtu (~$5.18 MM/yr) Note: This rate is a questimate based upon Buck and WS Lee estimated rates supplied by Piedmont Greensboro fuel oil terminal (~33 miles) ~1 miles to Transco. Not connected to existing P/L GREEN	9 miles to pipeline, average accessibility, good operating condition, average LDC impacts. Currently at 460 psi min. Natural gas indicative 100% daily demand rate ~$0.10/MMBtu (~$5.18 MM/yr) Note: This rate was supplied by Piedmont on 02/11/2013 for a 3x1 CC (~1200 MW) PB. ~9 miles to Transco. Connected to Piedmont Natural Gas. J Trimble said PNG would add a compressor and use the existing line in to Buck for gas supply. Also, there is adequate space for an added gas metering station. GREEN	3 miles to pipeline, good accessibility, good operating condition, average LDC impacts. Currently at 460 psi min. Natural gas indicative 100% daily demand rate ~$0.10/MMBtu (~$5.18 MM/yr) Note: This rate is a questimate based upon Buck and WS Lee estimated rates supplied by Piedmont ~3 miles to Transco. Connected to Piedmont GREEN	1 mile to pipeline, excellent accessibility, good operating condition, average LDC impacts Natural gas indicative 100% daily demand rate ~$0.106/MMBtu (~$5.49 MM/yr) Note: The above rate was supplied by Piedmont on 10/22/2012 for a 2x1 CC (~600 MW) ~1 miles to Transco. Connected to Piedmont GREEN	Gas on site, excellent accessibility, good operating condition, average LDC impacts Natural gas indicative 100% daily demand rate ~$0.10/MMBtu (~$5.18 MM/yr) Note: This rate is a questimate based upon Buck and WS Lee estimated rates supplied by Piedmont ~1 miles to Transco. Connected to Piedmont GREEN	2-4 miles to pipeline, Good accessibility, good operating condition, average LDC impacts Natural gas indicative 100% daily demand rate ~$0.10/MMBtu (~$5.18 MM/yr) Note: This rate was supplied by Piedmont on 02/11/2013 for a 3x1 CC (~1200 MW) PB. ~9 miles to Transco. Not connected to existing P/L GREEN	Gas on site, excellent accessibility, good operating condition, average LDC impacts Natural gas indicative 100% daily demand rate ~$0.10/MMBtu (~$5.18 MM/yr) Note: This rate is a questimate based upon Buck and WS Lee estimated rates supplied by Piedmont ~1 miles to Transco. Not connected to existing P/L GREEN
Water Permitting GREEN: Existing permit/no withdrawal issues YELLOW: Existing permit w/ issues or new permit w/o issues RED: New permit, water withdrawal issues	Existing NPDES permit would require modification—use of existing intake and cooling pond may qualify for 316b rules for existing facilities GREEN	Existing NPDES permit would require modification—use of existing intake may qualify for 316b rules for existing facilities Once-through cooling may not be allowed necessitating year-round operation of cooling towers GREEN	Existing NPDES permit would require modification—use of existing intake may qualify for 316b rules for existing facilities Once-through cooling may not be allowed necessitating year-round operation of cooling towers Subject to Surface Water Withdrawal regs and Lake is small YELLOW	New NPDES permit would be required—likely water source would be Harris Lake (dependent on the effect of consumptive use on Harris Nuclear Plant's operations) YELLOW	No public water available, well water unknown. New NPDES permit required—likely water source would be the Yadkin River Could have ROW issues. YELLOW	No public water available, well water and Yadkin River available.Minimal issues on modifying NPDES, but new discharge may be required due to planned retirement. Need to determine long term use of existing intake and discharge. GREEN	Municipal Water - City of Eden, No well wate available, Dan River available. Minimal issues expected with NPDES permitting GREEN	No public water or well water available, Withdraw from Saluda River. Minimal issues with waste water permitting, but new discharge may be required if existing ash basins were to be retired. GREEN /YELLOW	Public water from Lincoln County available, well water available, No river access/available. Lincoln County and Lincolnton have or can develop added capacity for 10 MGD. Minimal issues with waste water permitting – Lincoln County Waste Treatment adjacent to site discharges 1 MGD effluent. While it would take work, sufficient water appears available. Miniminzes permitting. YELLOW	No public or well water currently available at the site. Yadkin River available. New NPDES required. Need to investigate potential for public water provided to the site. YELLOW HLL asked Dave Phillips to inquire about available water near Mill Creek	No public or well water. Pond on site. 2.9 miles to Pacolet River. New NPDES required – could have ROW issues. RED
Air Permitting GREEN: Able to net out. In attainment of NAAQS YELLOW: New Permit/In attainment OR Non-attainment w/o Offsets RED: New permit, Non-Attainment, No Offsets and Class I Impacts	Existing air permit would require modification—may be able to take "credit" for retired emissions In attainment of all NAAQS. GREEN	Existing air permit would require modification—may be able to take "credit" for retired emissions In attainment of all NAAQS. GREEN	Existing air permit would require modification—may be able to take "credit" for retired emissions. In attainment of all NAAQS. GREEN	New permit required. In attainment of all NAAQS. YELLOW	New permit required. No option for PSD/NSR avoidance. DAQ will propose area as attainment for ozone , but EPA must approve. Proximate to Class I areas No Airspace within one mile. YELLOW	Non-attainment for Charlotte area ozone, PSD/NSR avoidance probable with retirement of Buck 5&6. Rowan is non-attainment for NOx and VOCs, but Buck has offsets available YELLOW	PSD/NSR avoidance - Possible with retirement of Dan River 3 however, timing for netting may be challenging. NC has recommended County as Attainment for all pollutants. EPA draft response expected in December 2011. YELLOW	Possible with retirement of existing coal capacity; may be able to net out of all but CO and VOC. SC DHEC will propose Anderson County as attainment for ozone but EPA must approve. There is some risk of non-attainment for the broader Upstate SC region. Proximate to Class I areas small private airport within one mile. GREEN	No PSD/NSR avoidance. Non-attainment for Charlotte area ozone, Close to Riverbend – Offsets available from Buck Proximate to Class I areas No airspace within one mile YELLOW	No PSD/NSR avoidance. Davie and Davidson Counties in attainment of all NAAQS Proximate to Class I areas, will involve FLM No airspace within one mile YELLOW	No PSD/NSR avoidance. SC DHEC will propose Cherokee County as attainment for ozone but EPA must approve. There is some risk of non-attainment for the broader Upstate SC region. Proximate to Class I areas No airspace within one mile YELLOW

Land Availability GREEN, YELLOW, [redacted] subjectively based on data provided	Adequate space exists once the fossil unit is town down—depends on stage of site demolition and restoration YELLOW	Adequate—depends on stage of site demolition and restoration. The T-line ROW and the existing facility consume a lot of the land owned. YELLOW	Location of retired Unit 1 may be unsuitable due to proximity to Unit 2 (nuclear) Adjacent Darlington County site may be more suitable YELLOW	Space is not a constraint—adequate land for future expansion beyond initial development	Duke does not own, but the site area is adequate—former NCEMC site was 438 acres Need to confirm ownership YELLOW	Duke owns ???? ac Potential Plant Location in CTCC laydown area. Potential Laydown Area in Fuel Oil or Coal Pile. It may be difficult to to find available land. YELLOW	Duke owns ???? ac Potential Plant Location in CTCC laydown area. Potential Laydown Area in Fuel Oil or Coal Pile. It may be difficult to to find available contiguous land. [redacted]	Duke owns 689 ac Potential Plant Location South of Lee Steam Plant. Potential Laydown Area in South of LSP between road & transmission YELLOW	Duke owns a lot of land 1700???? ac Potential Plant Location ??? Potential Laydown Area ????? GREEN	Duke owns ???? ac Very large site - could be strategically located for best gas and transmission access. Potential Laydown Plentiful on site GREEN	Duke does NOT own this property (532 ac) YELLOW
Other Environmental Considerations GREEN, YELLOW, [redacted] subjectively based on data provided	Assessment of potential environmental liabilities from prior operation required—ongoing oil tank leak remediation needs to be considered [redacted]	Assessment of potential environmental liabilities from prior operation required Implications of construction in the FEMA flood zone needs careful consideration YELLOW	Assessment of potential environmental liabilities from prior operation required Any nuclear licensing considerations need to be resolved Nuke plant may retire in near future YELLOW	An assessment of the site for wetlands, endangered species, and archaeological resources will be required YELLOW	A Phase I Environmental Assessment and an assessment of wetlands, endangered species, and archaeological resources will be required Sensitive Species: Eastern small footed myotis YELLOW	Potential for some groundwater issues Sensitive Species - Piedmont Indigo Bush, Eastern Small-Footed Myotis, Wading Bird Colony YELLOW	High potential for contaminated soil and rock will cause difficulty in undergrounds Sensitive Species - Roanoke hog sucker,green floater, bigeye jumprock [redacted]	No sensitive species GREEN	No sensitive species GREEN	No known soil issues Coolemee Plantation is 0.42 miles from property line . Listed on National Register of Historic Places. Potential concern over view shed or visibility. Sensitive areas: Creamy tick trefoil, Eastern small footed myotis, Robust Redhorse, Crested Coralroot, Dry mesic oak hickory forest, mesic mixed hardwood forest, Piedmont/low mountain alluvial forest, low elevation seep/ Eastern small footed myotis, Spring Coralroot, Crested Coralroot, Dry mesic oak hickory forest, mesic mixed hardwood forest, Piedmont/low mountain alluvial forest, Piedmont mountain levee forest, Piedmont mountain bottomland forest YELLOW	Greenfield - Significant development required. YELLOW
Zoning Considerations GREEN, YELLOW, [redacted] subjectively based on data provided	Recently acquired property zoned Industrial (H1)—existing site will need to be rezoned H1 GREEN	Much of the existing site is zoned Heavy Industrial or Conditional Use—Heavy Industrial GREEN	No zoning regulations currently in place GREEN	Harris lands except for the existing plant site are zoned Residential and would require rezoning to Industrial 1 YELLOW	CU-HI Rezoning to Heavy Industrial (HI) would be required Designated for a Utility YELLOW?? GREEN??	IND Designated as Industrial GREEN	RA Designated as Industrial GREEN	R-D Designated as Residential – Agricultural YELLOW	I-G Designated as Industrial in Future Land Use Plan GREEN	RA-1 and RA-2; R-A Designated for a Utility; Designated as Rural/Residential YELLOW	No zoning or Land Use designation on site GREEN
Community Relations Considerations GREEN, YELLOW, [redacted] subjectively based on data provided	Enthusiastic local support for locating a gas-fired generating facility in Robeson County would be expected in light of the retirement of the Weatherspoon Plant GREEN	Strong community support would be expected in light of the retirement of the Cape Fear Plant GREEN	Very positive support from the community and community leaders would be anticipated in light of the retirement of Unit 1 GREEN	No significant community opposition anticipated With retirement of Cape Fear Plant, Chatham County officials would oppose the new generation being in Wake County YELLOW	County interested in economic development, jobs, and added tax base--likely would be very supportive Greenfield however relatively flat farmland and good external tree buffer. GREEN	No					

For the purposes of developing background information to use in ranking sites, 800 MW was assumed as the generating capacity. Actual generating capacity may range from 700 MW to 900 MW.

Land area (Construction and operations): 75 acres required

Cooling water requirement: 8MGD, 12 CFS

There is some uncertainty/risk that permitting for a new facility could trigger an evaluation of the attainment status of for SO2 or NOx NAAQS. It is possible that an agency may require gathering of ambient monitoring data for SO2 prior to submitting an application, particularly if there are nearby emission sources, because EPA is labeling most areas of the country as "unclassifiable" due to limited monitoring data. However, that risk may be minimal for a well controlled source that is fairly remote from other facilities.

Landseidel Direct Exhibit 4

Duke Energy®

Generator Interconnection Request

System Impact Study Report

For: Duke Energy

2x1 Combined Cycle Plant

Service Location: Anderson County

Total Output: 776 MW

Commercial Operation Date: 6/1/2016

In-Service Date (if given): 9/1/2015

Prepared By: Orvane Piper **Date:3/11/2013**

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1.0 Introduction

Following are the results of the Generation System Impact Study for the installation of 776 MW of generating capacity in Anderson County, SC. This site is located near Lee Steam Station and has an estimated Commercial Operation Date of 6/1/2016. This study evaluates Network Resource Interconnection Service (NRIS).

2.0 Study Assumptions and Methodology

The power flow cases used in the study were developed from the Duke internal year 2016 summer peak case. This case contains the planned generation additions at Lee Combined Cycle Plant. The results of Duke's annual screening were used as a baseline to identify the impact of the new generation. To determine the thermal impact on Duke's transmission system, the new generation was modeled at a new interconnection station on the same site with the existing Lee Steam Station. Construction of the new interconnection station will involve modification of two existing circuits. The economic generation dispatch was also changed by adding the new generation and forcing it on prior to the dispatch of the remaining Duke Balancing Authority Area units. The impacts of changes in the Generator Interconnection Queue were evaluated by creating models with previously queued generators removed. The study cases were re-dispatched, solved and saved for use.

The NRIS thermal study uses the results of Duke Energy Transmission Planning's annual internal screening as a baseline to determine the impact of new generation. The annual internal screening identifies violations of the Duke Energy Power Transmission System Planning Guidelines and this information is used to develop the transmission asset expansion plan. The annual screening provides branch loading for postulated transmission line or transformer contingencies under various generation dispatches. The thermal study results following the inclusion of the new generation were obtained by the same methods, and are therefore comparable to the annual screening. The results are compared to identify significant impacts to the Duke Energy transmission system.

Stability studies are performed using an MMWG dynamics model that has been updated with the appropriate generator and equipment parameters for the new units. The SERC dynamically reduced 2016 summer peak case was used for this study. The case was modified to turn off some units to offset the new generation. Several transmission system improvements were identified for the addition of these units during the power flow portion of the interconnection request and were added to the dynamics case. NERC Category B, Category C, and Category D faults were evaluated.

Fault studies are performed by modeling the new generator and previously queued generation ahead of the new generator in the interconnection queue. Any significant changes in fault duty resulting from the new generator's installation are identified. Various faults are placed on the system and their impact versus equipment rating is evaluated.

Reactive Capability is evaluated by modeling a facility's generators and step-up transformers (GSU's) at various taps and system voltage conditions. The reactive capability of the facility can be affected by many factors including generator capability limits, excitation limits, and bus voltage limits. The evaluation determines whether sufficient reactive support will be available at the Connection Point.

Duke Energy

3.0 Thermal Study Results

3.1 NRIS Evaluation

The following network upgrades were identified as being attributable to the studied generating facility:

Facility Name/Upgrade	Existing Size/Type	Proposed Size/Type	Mileage	Estimated Cost	Lead Time (months)
1. Interconnection cost [1]	N/A	N/A	N/A	$10.5 M	30
2. Convert Greenbriar to Switching Station	N/A	N/A	N/A	$3 M	24
3. Upgrade Duncan 100 kV Lines (Inman – Campton Retail)	266 ACSR	556 ACSR	2.1	$2.9 M	24
4. Upgrade Greenbriar 100 kV (Shady Grove – Moonville Retail)	477 ACSR	B-477 ACSR	3.48	$5.8 M	24
5. Upgrade Oakvale 100 kV Lines (Shady Grove – Oakvale)	B-477 ACSR	B-954 ACSR	4.09	$6.8 M	18
6. Upgrade Tiger 100 kV Lines (Tiger – Walden Tap)	266 ACSR	556 ACSR	8.28	$11.2 M	30
7. Upgrade Union 100 kV Lines (O'Neal Retail – Pebble Creek Retail)	2/0 Cu	556 ACSR	3.03	$4.1 M	18
THERMAL NRIS CUSTOMER COST ESTIMATE				$44.3 M	30

The two higher queued projects below did not affect the identified upgrades.

- Queued project 40633-01 (355 MW combustion turbine facility in Cleveland County, NC):
- Queued project 40639-01 (937 MW combined cycle facility in Cleveland County, NC)

4.0 Fault Duty Study Results

The following breakers will need to be replaced:

1. At East Greenville Tie the following 100 kV breaker: Sevier Wh

[1] The interconnection cost includes the new 100 kV switching station and associated facilities (bus lines, relocation of lines, Lee Steam Station modifications).

2. At Lee Steam Station the following seven 100 kV breakers: Bank 3A HT Red & Yellow, Central Bl & Wh, Lee Bl & Wh, Piedmont Wh, Rabon Bl
3. At Lee Combined Cycle the following two 100 kV breakers: Broadway Wh, Toxaway Wh
4. At Shady Grove the following four 100 kV breakers: Greenbriar Bl & Wh, Oakvale Bl & Wh

Total estimated cost for breaker replacements: $1.7 M

5.0 Stability Study Results

Two NERC Category C5 faults, thirteen D2 faults, and two D7 faults were initially unstable. The C5 and D7 faults all included instantaneous reclosing on one or more lines. When instantaneous reclosing was disabled, all of these faults became stable. Eliminating or delaying reclosing is recommended for all 100 kV transmission lines at Lee.

All D2 faults were unstable. These involve a three-phase fault on a 100 kV line near Lee, with the Lee breaker failing to open. For the double-bus, single-breaker design of Lee Steam and CC 100 kV switchyards, a line breaker failure results in loss of about half the branches at that switchyard. The assumed breaker failure clearing time is 18 cycles, including the 12 cycle intentional delay. This intentional delay would have to be reduced to as low as 3 cycles. If these reduced breaker failure delays are not feasible, any reduction would improve the chances for stability, for example if the fault were farther out on the line or if the fault had non-zero impedance.

NERC does not require stability for Category D faults because of their low probability of occurrence. As such, no solutions are required for the unstable Category D faults.

Because loss of synchronism on Lee CC units was seen for some faults in this study, the installation and operation of the out-of-step protection is recommended to minimize the possibility of generator damage during the loss of synchronism condition.

The manufacturer proposed power system stabilizers (PSS) were not studied because there was sufficient damping without them. However, a PSS should be purchased along with each exciter. If problems arise in the future, then the facility can quickly implement a PSS solution.

The addition of the proposed 776 MW to the Lee Steam Station under the assumption that two of the three existing units are retired does present some stability concerns. However, with the solutions outlined in this report, the Customer's proposed 776 MW generating facility will not negatively impact the overall reliability of the generators or the interconnected transmission system.

6.0 Reactive Capability Study Results

With the proposed generating facility, the level of reactive support supplied by the units has been determined to be acceptable at this time. Evaluation of MVAR flow and voltages in the vicinity of Lee Steam Station indicates adequate reactive support exists in the region.

Study completed by: _____
Orvane Piper , Duke Energy

Reviewed by: _____
Ben Harrison , Duke Energy
Director, Transmission Planning Carolinas

Landseidel Direct Exhibit 5

DUKE ENERGY®

Optional Studies Report

For: Duke Energy ("Customer")

Queue #: 41219-01

Service Location: Anderson County

Total Output: 776 MW

Commercial Operation Date: 6/1/2016

Date: **5/16/2013**

Prepared by:
Orvane Piper, Duke Energy

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6.0 Reactive Capability Study Results 7

1.0 Introduction

Following are the results of the Generation Optional Studies for the installation of 776 MW of generating capacity in Anderson County, SC. Optional studies were performed to identify the impact of the following options for unit 3 at the existing plant: retired, repowered at 100 MW, and repowered at 135 MW. This site is located near Lee Steam Station and has an estimated Commercial Operation Date of 6/1/2016. This study includes Network Resource Interconnection Service (NRIS).

2.0 Study Assumptions and Methodology

The power flow cases used in the study were developed from the Duke internal year 2016 summer peak case. This case contains the planned generation additions at Lee Combined Cycle Plant. The results of Duke's annual screening were used as a baseline to identify the impact of the new generation. To determine the thermal impact on Duke's transmission system, the new generation was modeled at a new interconnection station on the same site with the existing Lee Steam Station. Construction of the new interconnection station will involve modification of two existing circuits. The economic generation dispatch was also changed by adding the new generation and forcing it on prior to the dispatch of the remaining Duke Balancing Authority Area units. Unit 3 at Lee Steam Station was dispatched at the level corresponding to the option selected for each study. The impacts of changes in the Generator Interconnection Queue were evaluated by creating models with previously queued generators removed. The study cases were re-dispatched, solved and saved for use.

The NRIS thermal study uses the results of Duke Energy Transmission Planning's annual internal screening as a baseline to determine the impact of new generation. The annual internal screening identifies violations of the Duke Energy Power Transmission System Planning Guidelines and this information is used to develop the transmission asset expansion plan. The annual screening provides branch loading for postulated transmission line or transformer contingencies under various generation dispatches. The thermal study results following the inclusion of the new generation were obtained by the same methods, and are therefore comparable to the annual screening. The results are compared to identify significant impacts to the Duke Energy transmission system.

Stability studies are performed using an MMWG dynamics model that has been updated with the appropriate generator and equipment parameters for the new units. The case is modified to turn off some units to offset the new generation. If transmission system improvements are identified for the addition of these units during the power flow portion of the interconnection request, they are added to the dynamics case. NERC Category B, Category C, and Category D faults are evaluated.

Fault studies are performed by modeling the new generator and previously queued generation ahead of the new generator in the interconnection queue. Any significant changes in fault duty resulting from the new generator's installation are identified. Various faults are placed on the system and their impact versus equipment rating is evaluated.

Reactive Capability is evaluated by modeling a facility's generators and step-up transformers (GSU's) at various taps and system voltage conditions. The reactive capability of the facility can be affected by many factors including generator capability limits, excitation limits, and bus voltage limits. The evaluation determines whether sufficient reactive support will be available at the Connection Point.

DUKE ENERGY.

3.0 Thermal Study Results

3.1 NRIS Evaluation

The following network upgrades were identified as being attributable to the studied generating facility:

WITH LEE 3 EITHER RETIRED OR REPOWERED TO 100 MW:

Facility Name/Upgrade	Existing Size/Type	Proposed Size/Type	Mileage	Estimated Cost	Lead Time (months)
1. Interconnection cost	N/A	N/A	N/A	$10.5 M	30
2. Convert Greenbriar to Switching Station	N/A	N/A	N/A	$3 M	24
3. Upgrade Greenbriar 100 kV Lines (Shady Grove – Moonville Retail)	477 ACSR	B-477 ACSR	3.48	$5.8 M	24
4. Upgrade Union 100 kV Lines (O'Neal Retail – Pebble Creek Retail)	2/0 Cu	556 ACSR	3.03	$3.3 M	18
THERMAL NRIS CUSTOMER COST ESTIMATE				$22.6 M	30

DUKE ENERGY.

WITH LEE 3 REPOWERED TO 135 MW:

Facility Name/Upgrade	Existing Size/Type	Proposed Size/Type	Mileage	Estimated Cost	Lead Time (months)
1. Interconnection cost	N/A	N/A	N/A	$10.5 M	30
2. Convert Greenbriar to Switching Station	N/A	N/A	N/A	$3 M	24
3. Upgrade Greenbriar 100 kV Lines (Shady Grove – Moonville Retail)	477 ACSR	B-477 ACSR	3.48	$5.8 M	24
4. Upgrade Tiger 100 kV Lines (Tiger – Lelia Retail Tap)	266 ACSR	556 ACSR	5.27	$5.6 M *	18
5. Upgrade Union 100 kV Lines (O'Neal Retail – Pebble Creek Retail)	2/0 Cu	556 ACSR	3.03	$3.3 M	18
THERMAL NRIS CUSTOMER COST ESTIMATE				$28.2 M	30

*Upgrade 4 is not required if either queued project 40633-01 (355 MW combustion turbine facility in Cleveland County, NC) or queued project 40639-01 (937 MW combined cycle facility in Cleveland County, NC) is built.

WITH LEE 3 REPOWERED TO 172 MW:

Facility Name/Upgrade	Existing Size/Type	Proposed Size/Type	Mileage	Estimated Cost	Lead Time (months)
1. Interconnection cost	N/A	N/A	N/A	$10.5 M	30
2. Convert Greenbriar to Switching Station	N/A	N/A	N/A	$3 M	24
3. Upgrade Greenbriar 100 kV Lines (Shady Grove – Moonville Retail)	477 ACSR	B-477 ACSR	3.48	$5.8 M	24
4. Upgrade Lee 100 kV Lines (Lee - Shady Grove)	477 ACSR	B-477 ACSR	11.74	$19.3 M *	36
5. Upgrade Oakvale 100 kV Lines (Shady Grove – Oakvale)	B-477 ACSR	B-954 ACSR	4.09	$7.5 M *	18
6. Upgrade Tiger 100 kV Lines (Tiger – Lelia Retail Tap)	266 ACSR	556 ACSR	5.27	$5.6 M *	18
7. Upgrade Union 100 kV Lines (O'Neal Retail – Pebble Creek Retail)	2/0 Cu	556 ACSR	3.03	$3.3 M	18
THERMAL NRIS CUSTOMER COST ESTIMATE				$55 M	30

*Upgrades 4-6 are not required if queued project 40639-01 (937 MW combined cycle facility in Cleveland County, NC) is built.

3.2 ERIS Evaluation

The Customer did not request an evaluation of ERIS service.

4.0 Fault Duty Study Results

At the request of the Customer this analysis was not performed. This analysis would be required before interconnection.

5.0 Stability Study Results

At the request of the Customer this analysis was not performed. This analysis would be required before interconnection.

6.0 Reactive Capability Study Results

With the proposed generating facility, the level of reactive support supplied by the units has been determined to be acceptable at this time. Evaluation of MVAR flow and voltages in the vicinity of Lee Steam Station indicates adequate reactive support exists in the region.

Study completed by: _____
Orvane Pipes, Duke Energy

Reviewed by: _____
Ben Harrison, Duke Energy
Director, Transmission Planning Carolinas

Date: **5/16/2013**

See Hearing Exhibit 5
for confidential document

BEFORE
THE PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA
DOCKET NO. 2013-___-E

In Re:	)	
	)	
Application of Duke Energy Carolinas, LLC and North Carolina Electric Membership Corporation For a Certificate of Environmental Compatibility And Public Convenience and Necessity for the Construction and Operation of a 750 MW Combined Generating Plant Near Anderson, South Carolina	)	**APPLICATION FOR CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AND PUBLIC CONVENIENCE AND NECESSITY**

CONFIDENTIAL

Mark E. Landseidel
EXHIBT 6

FILED UNDER SEAL

OCTOBER 24, 2013

SOUTHERN ENVIRONMENTAL LAW CENTER

Telephone 843-720-5270

43 BROAD STREET, SUITE 300
CHARLESTON, SC 29401-3051

Facsimile 843-720-5240

February 7, 2014

Jocelyn Boyd, Esquire
Chief Clerk
South Carolina Public Service Commission
P.O. Drawer 11649
Columbia, SC 29211

RE: In the Matter of: Joint Application of Duke Energy Carolinas, LLC and North Carolina Electric Membership Corporation for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of a 750MW Combined Generating Plant Near Anderson, SC
Docket No. 2013-392-E

Dear Ms. Boyd:

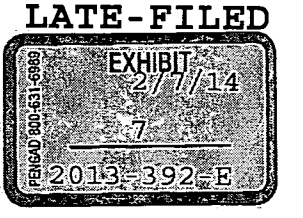
Enclosed for filing in the referenced docket is Late-filed Exhibit summarizing a number of projects in which renewable energy has been paired with or supplanted fossil fuel plants. This information responds to a question raised at the hearing by Commissioner Fleming.

Thank you and please contact me if you have further questions.

Sincerely,

s/ J. Blanding Holman, IV
Attorney for Petitioners

Cc: Parties of Record



STATE OF SOUTH CAROLINA
BEFORE THE PUBLIC SERVICE COMMISSION
DOCKET NO. 2013-392-E

Late-Filed Exhibit
South Carolina Coastal Conservation League and Southern Alliance for Clean Energy
Examples of Solar Projects Linked to Natural Gas Generation

FPL: Martin Next Generation Solar Energy Center
Florida Power & Light's ("FPL") is a hybrid facility in which a 75 megawatt ("MW") solar thermal power plant is directly connected to a 1,142 MW combined-cycle natural gas power plant at FPL's Martin Plant. The solar facility entered commercial operation in December 2010 after construction was completed ahead of schedule and under budget. FPL estimates that the solar facility will save customers $178 million in fuel costs over its lifetime.[1] As explained by FPL, the solar facility is a "fuel-substitute facility" that "displaces the use of fossil fuel," and is "not a facility that provides additional capacity and energy."[2]

Xcel Colorado: Utility-Scale Wind/Solar/Gas Portfolio[3]
Xcel Colorado recently proposed adding 450 MW of wind power, 170 MW of utility-scale solar power, and 317 MW of natural gas generation. In announcing the proposal, Xcel that the natural gas generation "would provide operational flexibility the utility relies on to reliably integrate renewable resources into its electric supply mix."[4] The proposal was developed through a competitive Request For Proposals process approved by the Colorado Public Utilities Commission and overseen by an independent evaluator. According to the independent evaluator's report, the wind and solar resources reduce the overall portfolio cost by $262 million.[5] Notably, the operating cost would be reduced by $246 million (i.e., total cost savings less surplus capacity cost benefits), consistent with CCL and SACE's finding that a utility-scale solar power project could help to offset the operating costs of the proposed Lee natural gas combined cycle unit.

Northern States Power: Hearing Officer Recommendation for Solar/Gas Portfolio
In a competitive bidding process overseen by the Minnesota Public Utilities Commission to determine the most reasonable and prudent way to meet a capacity need demonstrated by

[1] Florida Power & Light, "FPL's Martin Next Generation Solar Energy Center," available at http://www.fpl.com/environment/solar/pdf/Martin.pdf.

[2] FPL, "Ten Year Power Plant Site Plan: 2013-2022," filed with the Florida Public Service Commission, available at http://www.fpl.com/about/ten_year/pdf/plan.pdf .

[3] Note: This example is discussed on pages 18-19 of the Joint Direct Testimony of Hamilton Davis and John D. Wilson that was filed in this docket on December 10, 2013 on behalf of CCL and SACE.

[4] Xcel Energy News Release, "Xcel Energy proposes adding economic solar, wind to meet future customer energy demands" (Sept. 10, 2013), available at http://www.xcelenergy.com/About_Us/Energy_News/News_Archive/Xcel_Energy_proposes_adding_economic_solar,_wind_to_meet_future_customer_energy_demands. .

[5] Accion Group, Independent Evaluator's Final Report (Public Version): Public Service Company of Colorado, 2013 All-Source Solicitation, Colorado Public Utilities Commission Proceeding 11A-869E (October 9, 2013) at 27, available at https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=252561&p_session_id= .

Northern States Power Company (d/b/a Xcel Energy), the Administrative Law Judge recommended that 71 MW of capacity need be met by Geronimo Energy's solar energy project proposal, and that a second competitive bidding process be undertaken for any remaining capacity.[6] Among other findings of fact, the ALJ found that "[t]he solar project has no associated fuel costs, and, therefore, provides for a fixed and certain price for the life of the project."[7]

LG&E / KU: New Natural Gas /Solar Plant Proposal

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") recently submitted a joint application to the Kentucky Public Service Commission for certificates of public convenience and necessity for the construction of a 700 MW natural gas combined cycle facility at KU's Green River Generating Station in Muhlenberg County, KY and the a 10 MW solar photovoltaic facility at KU's E.W. Brown Generating Station in Mercer County, KY.[8] After an RFP process, the companies determined that the gas-solar combination was the "least-cost reasonable alternative for meeting customer needs."[9]

[6] The hearing officer laid out specific steps for determining the amount, type and schedule for the additional capacity resources. State of Minnesota Office of Administrative Hearings for the Public Utilities Commission, , In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process, Findings of Fact, Conclusions of Law, and Recommendation, , MPUC Docket No. E-002 / CN-12-1240 (December 31, 2013) at 45-46, available at http://mn.gov/oah/images/2500-30760-NSP-competitive-resource-report.pdf.

[7] Id. at 17.

[8] LG&E and KU, Joint Application, Kentucky Public Service Commission Docket 2014-00002 (January 14, 2014), available at http://psc.ky.gov/pscecf/2014-00002/rick.lovekamp@lge-ku.com/01172014091513/LGE_KU_CPCN_App_Test_Exh_1-17-14.pdf.

[9] Id. at 4-5.

The undersigned hereby certifies that the Record on Appeal contains all material proposed to be included by any of the parties and not any other material.

February 20, 2015

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RECEIVED
MAR 11 2015
SC Court of Appeals

THE STATE OF SOUTH CAROLINA
In the Court of Appeals

Appellate Case No. 2014-001514

APPEAL FROM THE
PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA

RECEIVED
APR 22 2016
S.C. SUPREME COURT

Docket No. 2013-392-E

In The Matter of Joint Application of Duke Energy Carolinas, LLC and North Carolina Electric Membership Corporation for a Certificate of Environmental Compatibility and Public Convenience and Necessity for The Construction and Operation of a 750MW Combined Cycle Generating Plant Near Anderson, SC.

BRIEF OF RESPONDENTS DUKE ENERGY CAROLINAS, LLC AND NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION

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THE STATE OF SOUTH CAROLINA
In the Court of Appeals

Appellate Case No. 2014-001514

APPEAL FROM THE
PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA

Docket No. 2013-392-E

In The Matter of Joint Application of Duke Energy Carolinas, LLC and North Carolina Electric Membership Corporation for a Certificate of Environmental Compatibility and Public Convenience and Necessity for The Construction and Operation of a 750MW Combined Cycle Generating Plant Near Anderson, SC.

BRIEF OF RESPONDENTS DUKE ENERGY CAROLINAS, LLC AND NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION

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STATEMENT OF ISSUES ON APPEAL

1. Was the decision of the South Carolina Public Service Commission ("Commission") to grant a Certificate of Environmental Compatibility and Public Convenience and Necessity ("Certificate") for a natural gas-fired electricity generating facility supported by substantial evidence?

2. Did the Commission properly consider and reject Appellants' recommendation that it condition approval of the Certificate on the solicitation of proposals for a solar facility to be operated in tandem with the natural gas-fired generating facility?

STATEMENT OF THE CASE

This is an appeal from orders of the Commission granting a Certificate for the construction of the Lee Combined Cycle Project ("LCCP"), a natural gas-fired electricity generating plant in Anderson County. The proceeding before the Commission was initiated by the filing of an application by Duke Energy Carolinas, LLC ("DEC" or "the Company") and the North Carolina Electric Membership Corporation ("NCEMC") (collectively "Applicants" or "Respondents"). (R. Vol. I, p. 40.) The application was filed on October 24, 2013 pursuant to the provisions of the Utility Facility Siting and Environmental Protection Act ("the Act" or "the Siting Act") (codified at Chapter 33 of Title 58, S.C. Code of Laws Ann.) The application sought approval for a 750 megawatt ("MW") natural gas-fired combined cycle electricity generating plant to be located at the site of an existing generating facility operated by DEC in Anderson County, South Carolina. The Act requires notice of applications be provided to affected local governments and to agencies charged with protecting the environment. The Applicants certified that such notice was given.

The South Carolina Coastal Conservation League ("SCCCL") and the Southern Alliance for Clean Energy ("SACE") (collectively "Appellants") petitioned for and were granted leave to participate in the proceedings before the Commission. Also participating in the proceeding before the Commission was the Office of Regulatory Staff ("the ORS"). The ORS is a state agency created by Act 175 of 2004 and it is charged with the responsibility of representing the public interest in matters before the Commission. See S.C. Code Ann. § 58-4-10. On January 3, 2014 DEC, NCEMC and the ORS filed a settlement agreement with the Commission. (R. Vol. I, p. 20.) In the settlement

agreement the ORS endorsed and supported the issuance of the Certificate as requested in the application.

The Commission conducted hearings on the application on January 7, 2014 and February 4, 2014. Testimony and exhibits were submitted by Applicants, the ORS and Appellants. In their testimony Appellants did not ask the Commission to deny the application but instead made several different arguments that the Certificate be delayed or issued only with conditions attached. (R. Vol. I, p. 305.) On May 2, 2014 the Commission issued Order No. 2014-408 approving the application and issuing the Certificate. (R. Vol. I, p. 4.) Appellants filed a petition for rehearing on May 15, 2014. (R. Vol. I, p. 88.) In their petition for rehearing Appellants focused solely on an argument that the Commission should condition the issuance of the Certificate on a requirement that DEC solicit proposals for a 375 MW solar facility to be operated in conjunction with the LCCP. The Commission voted to deny the petition on June 4, 2014 and Appellants filed a notice of appeal with this Court on July 3, 2014. (R. Vol. I, p. 111.) The Commission issued Order No. 2014-546 denying the petition for rehearing on July 30, 2014. (R. Vol. I, p. 28.)

STATEMENT OF FACTS

Lee Combined Cycle Project

In their application DEC and NCEMC asked the Commission to issue a Certificate to allow the construction of the LCCP. In support of the application DEC and NCEMC presented evidence of the need for the facility, the suitability of the LCCP to meet that need and the environmental impact of the project. The Applicants submitted the DEC 2013 Integrated Resource Plan ("IRP") in support of the application. (R. Vol. II, p. 342.) The IRP is prepared by DEC pursuant to the provisions of S.C. Code Ann. § 58-37-40. The development of the DEC IRP is a detailed multi-step process that assesses various relevant planning considerations, including load forecasts, the impact of existing and likely environmental regulations, fuel costs and potential appropriate generation and efficiency resources to meet the needs that are identified. (R. Vol. I, p. 175.)

The DEC 2013 IRP showed an expected growth in demand of 1.5 percent per year over a 15 year planning period and a need for an additional 317 MWs in 2017, growing to 573 MW in 2018 and an additional 3400 MWs by 2028. (R. Vol. I, p. 157.) Through its IRP planning process DEC determined that the LCCP would best meet the identified needs. (R. Vol. I, pp. 157, 181-184, 193.) In particular the planning process and analysis showed that construction of the LCCP was the lowest cost approach for meeting the needs of DEC's customers. (R. Vol. I, p. 167.)

The need for the additional generation represented by the LCCP is driven in part by retirements of 1297 MWs of coal generation and 350 MWs of aging combustion turbine generation and additional planned retirements of 370 MWs of coal generation in

2015. (R. Vol. I, p. 180.) These retirements are driven largely by environmental considerations as the older plants are not able to meet newer air permit requirements. (R. Vol. I, pp. 180-181.) The proposed LCCP is expected to emit 69% less carbon dioxide, 98% less nitrogen oxide and 100% less sulfur dioxide than the coal units that are currently located on the same site in Anderson County. (R. Vol. I, pp. 157-158.)

The DEC and NCEMC application was also supported by testimony and exhibits showing the probable environmental impact of the LCCP. A siting study performed in 2011 and updated in 2013 was submitted. (R. Vol. I, pp. 274, 561.) The siting studies evaluated various factors including land availability, cultural and land use, natural gas availability, water availability, electric transmission and air permitting. (R. Vol. I, p. 273.)

The application by DEC and NCEMC for a Certificate for the LCCP was supported by ORS witness Gene Soult. Soult testified that the application met all of the requirements of the Act, (R. Vol. II, p. 333); that the overall environmental impact of the project will be positive (R. Vol. II, p. 335); and that the public convenience and necessity will be served by construction of the LCCP. (R. Vol. II, p. 336.)

The Appellants' Solar Proposal

The Appellants have not challenged DEC's need for the additional capacity the LCCP will provide or the appropriateness of the LCCP to provide this capacity. At the hearing on the DEC/NCEMC application Appellants made three different suggestions to the Commission for altering or conditioning the issuance of the Certificate. (R. Vol. I, p. 305.) However, in their petition for rehearing and on appeal they have focused on arguing that the Certificate should be conditioned upon DEC issuing an RFP for a 375

MW solar facility to be operated in conjunction with the natural gas facility.

Neither of the Appellants' witnesses who made the suggestion have any experience in the construction or operation of any type of electricity generation facility: one of the witnesses is a lawyer and the other is a public policy advocate. (R. Vol. I, pp. 302-303.) A 375 MW solar facility would be the largest such facility in the world, exceeding by 85 MW the size of a facility currently under construction in Arizona. (R. Vol. I, p. 319.) A 375 MW facility solar facility would require 2,625 acres of land. (R. Vol. I, p. 207.) No evidence was presented to the Commission to suggest where such a facility would be located. In fact, the Appellants suggested that the Commission might alternatively require a series of smaller solar installations across the State. (R. Vol. I, p. 320.)

The Appellants' witnesses estimated that their proposed solar facility would have a capacity factor of approximately 22% as compared to a 90% capacity factor for the proposed LCCP. (R. Vol. I, p. 317.) Appellants do not suggest that the solar facility they propose would replace or reduce the need for the natural gas facility. Instead they want both facilities built. (R. Vol. I, p. 316.) The Appellants' proposal is heavily dependent on the cost of their proposed solar facility, yet their witnesses offered two cost estimates that varied by a factor of 100% - from approximately $2000 per kilowatt to $4000 per kilowatt. (R. Vol. I, p. 317.)

ARGUMENT

I. Standard of Review

The South Carolina Supreme Court has recently had occasion to review the appropriate standard of review for appeals from the Commission. In Friends of the Earth v. Public Service Commission of South Carolina, 387 S.C. 360, 692 S.E.2d 910 (2010) the Court considered a decision by the Commission approving the construction of a nuclear generating plant. That decision was made under the Base Load Review Act which is similar to, and closely associated with, the Siting Act under which the Commission approved the LCCP. In the Friends of the Earth decision the Court rejected an argument that a stronger standard of review should be applied and instead applied its familiar standard of review for appeals from Commission decisions:

> Consequently, "[t]his Court employs a deferential standard of review when reviewing a decision of the Public Service Commission and will affirm that decision when substantial evidence supports it." Duke Power Co. v. Public Service Comm'n of South Carolina, 343 S.C. 554, 558, 541 S.E.2d 250, 252 (2001) (citing Porter v. South Carolina Public Service Comm'n, 333 S.C. 12, 507 S.E.2d 328 (1998)). In applying a substantial evidence test, an appellate court may not substitute its judgment for the judgment of the agency as to the weight of the evidence on questions of fact, unless its findings or conclusions are clearly erroneous in view of the reliable, probative and substantial evidence on the whole record. Lark v. Bi–Lo, Inc., 276 S.C. 130, 276 S.E.2d 304 (1981); S.C. Code Ann. § 1–23–380 (Supp. 2009). Substantial evidence is not a mere scintilla; rather, it is evidence which, considering the record as a whole, would allow reasonable minds to reach the same conclusion as the agency. Lark at 135–36, 276 S.E.2d at 306–07.
>
> Furthermore, the Court may not substitute its judgment for the Commission's on questions about which there is room for a difference of intelligent opinion. Duke Power Co., 343 S.C. at 558, 541 S.E.2d at 252. Because the Commission's findings are presumptively correct, the party challenging a Commission order bears the burden of convincingly proving the decision is clearly erroneous, or arbitrary or capricious, or an abuse of discretion, in view of the substantial evidence on the whole record. Id.

Friends of the Earth v. Public Service Commission, 387 S.C. at 365-366.

As is discussed more fully below, this is a substantial evidence case. The Commission's orders were amply supported by substantial evidence and should be affirmed. However, Appellants argue the Commission committed errors of law in interpreting the Siting Act. In assessing such arguments it is important that the Commission be given deference with respect to its interpretation of that legislation.

> We have traditionally given the PSC, just as any other agency, respectful consideration in their interpretation of a statute. Where an agency is charged with the execution of a statute, the agency's interpretation should not be overruled without cogent reason.

Nucor Steel, a Division of Nucor Corporation v. South Carolina Public Service Commission, 310 S.C. 539, 426 S.E.2d 319 (1992), citing South Carolina Cable Television v. Southern Bell, 308 S.C. 216, 417 S.E.2d (1992); Dunton v. South Carolina Board of Examiners in Optometry, 291 S.C. 221, 353 S.E.2d 132 (1987). As discussed below, the Commission's rejection of Appellants' solar proposal reflected a correct and entirely reasonable interpretation of the Siting Act and that interpretation is entitled to deference based on the Commission's role in implementing the provisions of the Act.

II. The Commission's Decision to Grant the Certificate for the Lee Combined Cycle Project Was Supported by Substantial Evidence.

In the Siting Act there are six specific findings that the Commission must make in order to issue a Certificate. These are set out in S.C. Code Ann. § 58-33-160. The Commission made specific findings regarding each requirement in its order granting the Certificate. (R. Vol. I, pp. 9-18.) A brief review of the evidence supporting the findings of the Commission follows.

a. **The basis of the need for the facility.** DEC submitted its 2013 IRP to support the need for the facility. (R. Vol. II, p. 342.) DEC witness Janice Hager, who oversaw the preparation of the IRP, testified in support of the IRP and explained how it was prepared and how it demonstrated that the LCCP met the need identified in the IRP. (R. Vol. I, pp. 166-169.) DEC witness Clark Gillespy, State President South Carolina, explained the need for additional resources in the 2017-2018 time period and the Company's conclusion that a 750 MW combined cycle natural gas-fired facility best met those needs. (R. Vol. I, p. 157.) ORS witness Gene Soult also testified about the ORS review of the 2013 IRP and the conclusion reached by the ORS that the need for the facility had been established. (R. Vol. II, p. 334.)

b. **The nature of the probable environmental impact.** DEC presented the testimony of Mark Landseidel, Director of Project Development and Initiation in support of its application. (R. Vol. I, p. 270.) Mr. Landseidel sponsored and explained two siting studies that DEC performed that explored potential sites for new generation. (R. Vol. I, p. 273; R. Vol. II, p. 503.) He testified that the studies reviewed various siting criteria including land availability, cultural and land use, natural gas availability, water availability, electric transmission, air permitting and proximity to existing facilities. (R. Vol. I, p. 273.) Landseidel also testified that the siting studies concluded the Anderson County site of the existing Lee Steam Station (a coal fired facility scheduled to be retired) was the best location for the proposed LCCP, taking into account all of these various factors including the probable environmental impact. (R. Vol. I, p. 273.)

c. **The impact of the facility upon the environment is justified, considering the state of available technology and the nature and economics of the various alternatives and other pertinent considerations.** In reaching its conclusion that the environmental impact of the LCCP was justified the Commission relied on the testimony of Gillespy, Hager and Landseidel and the 2013 IRP and siting studies. (R. Vol. I, p. 15.) The Commission explained why the resource need identified by the IRP could not be met by a solar facility:

> In the joint testimony of Mr. Davis and Mr. Wilson they advocate for a 375 MW solar facility to be located at or near the Lee site. Mr. Davis testified that, when conditions exist for economic solar energy production, the solar energy could offset generation from the LCCP. This Commission appreciates the desire for renewable sources of energy; however, in this instance, the need is for a specified level of capacity in conjunction with energy production and the two are not synonymous. Mr. Soult testified that the Company is expecting the LCCP to produce sufficient electricity to meet base or intermediate load requirements at an expected capacity factor between 50% to 75% for a period of 20 to 30 years. Solar energy has a much lower operating capacity factor due to its limited availability, making it not an optimal source for base or intermediate load.

(R. Vol. I, pp. 15-16.) There was substantial evidence supporting the Commission's conclusion that the LCCP was the right resource to meet the need that was identified.

d. **The facilities will serve the interests of system economy and reliability.** The testimony of Hager and Landseidel and the 2013 IRP show that the LCCP is the right resource to meet the needs of DEC's customers as demand grows and older plants are retired. ORS witness Soult offered this testimony on system economy and reliability: "The proposed power block is a proven design that is already in use in the Company's system. These existing units have demonstrated high

capacity factors and availability factors, which provides a good indication of the reliability of the LCCP when properly operated and maintained." (R. Vol. II, p. 335.)

e. **There is reasonable assurance that the proposed facility will conform to applicable State and local laws and regulations.** DEC witness Landseidel testified at length about the Company's experience with the operation of the combined cycle facility of the type proposed for the LCCP. (R. Vol. I, pp. 271-273; 276-279.) Mr. Soult confirmed and supported the Landseidel testimony that the Company had a track record of successful operation of the proposed facility. (R. Vol. II, p. 335.)

f. **The public convenience and necessity support the construction of the facility.** The Commission's decision that the LCCP will serve the public convenience and necessity is supported by the evidence described above that showed the need for additional generation resources, that the LCCP was the best, least cost choice to meet that need, and that its environmental impact is reasonable given the other factors.

The Commission's decision to issue a Certificate for the LCCP was clearly supported by substantial evidence. The Applicants submitted thorough and persuasive evidence on every element required by the Siting Act. The ORS, charged by statute with the responsibility of protecting the public interest, entered into a settlement agreement with DEC and NCEMC and supported issuance of the Certificate. Appellants have failed to make any showing that would support a reversal of the decision by the Commission to issue the Certificate.

III. The Commission Properly Considered and Rejected Appellants' Solar Proposal.

Appellants argue the Commission did not understand their solar proposal and therefore failed to properly consider it. Appellants argue the Commission therefore committed errors of law that require the orders granting the Certificate to be reversed. In fact the Commission's orders show it did understand the Appellants' solar proposal and that the Commission rejected it for compelling reasons. The Commission's decision to reject Appellants' proposal was based on the Commission's interpretation of the Siting Act and related provisions of the statutes governing the regulation of utilities in South Carolina. The Commission's interpretation of those statutory provisions was coherent, consistent and far more reasonable than the interpretation urged by Appellants.

The LCCP Addresses the Need Identified in the Application; Appellants' Solar Proposal Does Not.

The Siting Act provides a detailed process for the review of proposed major utility facilities. S.C. Code Ann. § 58-33-120 sets out the requirements for a Siting Act application including a statement of the need for the proposed facility and summaries of studies done to show how the proposed facility will meet those needs. S.C. Code Ann. § 58-33-160 sets out the findings the Commission must make in order to issue a certificate under the Siting Act. Those requirements focus on the need shown for a facility and how the proposed facility addresses that need. The likely environmental impact of the proposed facility is required to be weighed against the availability of other options to meet the need identified in the application.

In its orders that are now under review the Commission properly focused on the demonstrated need for the facility in rejecting Appellants' solar proposal.

> Solar energy has a much lower operating capacity factor due to its limited availability, making it not an optimal source for base or intermediate load. This Commission understands SCCL's and SACE's idea of having solar generation in lieu of LCCP electricity generation when solar conditions are right; however the LCCP could not be built with lower than the Company needed 650 MWs, since the Company has demonstrated a need for this additional capacity in the 2017-2018 time frame. The reliability and operating capacity of the proposed solar facility is below the required need; therefore, it is not appropriate to meet the capacity needs of the proposed project.

(R. Vol. I, pp. 15-16.) This analysis is exactly right and what is called for by the Siting Act. In their application DEC and NCEMC demonstrated a need for a facility to provide a level of capacity and reliability that no solar facility can provide. The Commission correctly determined that accepting the Appellants' solar proposal would be approving or ordering DEC to move forward on a facility for which no need had been demonstrated, a result that is at odds with the entire structure of the Siting Act.

Accepting the Appellants' Solar Proposal Would Have Meant Approving a Facility Different from the Facility for Which Notice Was Given.

The Siting Act contains several provisions designed to ensure that state environmental agencies and affected local governments are informed about proposals for utility facilities. S.C. Code Ann. § 58-33-120(2) requires that any Siting Act application be served on "...the Office of Regulatory Staff, the chief executive officer of each municipality, and the head of each state and local government agency, charged with the duty of protecting the environment or of planning land use, in the area of the county in which any portion of the facility is to be located." S.C. Code Ann. § 58-33-140(1)(b) automatically makes the ORS, the Department of Health and Environmental Control ("DHEC"), the Department of Natural Resources ("DNR") and the Department of Parks Recreation and Tourism ("PRT") parties to any proceeding under the Act.

In the present proceeding, as required by the Act, the Applicants certified that the application and supporting materials were served on all statutorily required entities. (R. Vol. I, pp. 48-49.) Those entities therefore received documents explaining the resource need identified by the Dec 2013 IRP and the Applicants proposal for meeting those needs, the LCCP. Attached to the application was the testimony of Mark Landseidel and his exhibits, including the siting studies that he described in the testimony. (R. Vol. I, pp. 42, 269; Vol. II, p. 561.) Recipients of these documents would have been informed in detail about the proposed LCCP and its potential environmental impact. What the recipients would not have received was any information whatsoever about a proposal for the largest solar facility in the world that would require approximately 2625 acres. (R. Vol. I, pp. 207, 319.) The Commission correctly pointed out that accepting the Appellants' solar proposal would be expanding the scope of the application without notice to the public in contravention of the notice provisions of the Act. (R. Vol. I, pp. 15-16.)

Appellants' argument seems to be based on the assumption that the only environmental impact at issue in this Siting Act proceeding is the impact of carbon emissions from a natural gas facility. The Siting Act clearly contemplates a much wider range of potential impacts to be considered, as evidenced by the fact that local governments and planning agencies, as well as DNR and PRT are statutorily required to be given notice. The Commission was clearly correct when it determined that an order in this proceeding requiring the development of a giant solar facility without notice would not be consistent with the provisions of the Siting Act.

The Appellants' Solar Proposal is Inconsistent with the Commission's Approach to Least Cost Planning under S.C. Code Ann. § 58-27-865(F).

In its order denying Appellants' petition for rehearing the Commission addressed a different aspect of the solar proposal, specifically Appellants proposal that the solar facility would be operated in conjunction with the LCCP such that the LCCP would be operated only when the solar facility was not able to generate electricity. The Commission found this aspect of Appellants' proposal to be inconsistent with the requirements of S.C. Code Ann. § 58-27-865(F) which requires that "[t]he Commission shall disallow recovery of any fuel cost that it finds without just cause to be the result of failure of the utility to make every reasonable effort to minimize fuel costs or any decision of the utility resulting in unreasonable fuel costs..." As the Commission pointed out, that provision requires the Commission to examine the Company's operations on a much broader basis than proposed by the Appellants:

> For instance, the proposition of setting a benchmark price for solar energy bids that is at or below the long term operating cost of the gas facility is an appealing argument from the perspective of displacing gas power with solar power, but that benchmark price is outside the statute's criteria if wholesale power can be purchased below the benchmark. In this regard, the price of solar power is required to compete with the price of all fuel options.

(R. Vol. I, p. 33.)

The Commission's analysis is exactly right: Appellants propose to operate the LCCP and the hypothetical solar facility without consideration for all of the other generation assets on the DEC system. At the time of the hearing Janice Hager listed the various generation resources of DEC: 7,172 MW of coal generation; 1,240 MW of combined cycle; 2,770 MW of combustion turbine; 5,965 MW of nuclear; 3,229 MW of hydro; 251 MW of purchases; 911 MW of DSM and 185 MW of renewables. (R. Vol. I,

p. 180.) S.C. Code Ann. § 58-27-865(F) requires that the Commission review the Company's use and management of all of these resources as a whole in an effort to minimize fuel costs. The Appellants' solar proposal, which would require a separate review of two generating facilities, is antithetical to the statutorily required approach. It was appropriately rejected by the Commission.

CONCLUSION

DEC and NCEMC presented thorough and compelling evidence supporting their application for the Certificate under the Siting Act. The Commission's decision to issue the Certificate was supported by substantial evidence and should be affirmed pursuant to the standard of review described by the Friends of the Earth v. Public Service Commission, *supra*. The Commission's decision to reject the Appellants' solar proposal was also correct as a matter of law and amply supported by substantial evidence. The Commission's analysis reflected a clear understanding of the proposal and the reasons why it was inconsistent with the Siting Act, as well as the least cost planning provisions of S.C. Code Ann. § 58-27-865(F).

Respondents DEC and NCEMC ask that the Commission's orders be affirmed in all respects.

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March 9, 2015

THE STATE OF SOUTH CAROLINA
In the Court of Appeals

Appellate Case No. 2014-001514

APPEAL FROM THE
PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA

Docket No. 2013-392-E

In The Matter of Joint Application of Duke Energy Carolinas, LLC and North Carolina Electric Membership Corporation for a Certificate of Environmental Compatibility and Public Convenience and Necessity for The Construction and Operation of a 750MW Combined Cycle Generating Plant Near Anderson, SC.

Rule 211(b) Certificate

I hereby certify that Respondents' Brief being filed contemporaneously herewith complies with Rule 211(b) of the SC Appellate Court Rules.

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SC Court of Appeals

THE STATE OF SOUTH CAROLINA
In the Court of Appeals

Appellate Case No. 2014-001514

APPEAL FROM THE
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CERTIFICATE OF SERVICE

This is to certify that I, Toni C. Hawkins, a paralegal with the law firm of Robinson, McFadden & Moore, P.C., have this day caused to be served upon the persons named below a copy of the Brief of Respondents Duke Energy Carolinas, LLC and North Carolina Electric Membership Corporation in the foregoing matter by placing a copy of same in the United States Mail, postage prepaid, in an envelope addressed as follows:

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THE STATE OF SOUTH CAROLINA
In the Court of Appeals

Appellate Case No. 2014-001514

APPEAL FROM THE PUBLIC SERVICE COMMISSION

Docket No. 2013-392-E

In The Matter of Joint Application of Duke Energy Carolinas, LLC and North Carolina Electric Membership Corporation for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of a 750MW Combined Generating Plant Near Anderson, SC

FINAL REPLY BRIEF OF APPELLANTS SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND SOUTHERN ALLIANCE FOR CLEAN ENERGY

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73B C.J.S. *Public Utilities* § 186 (2013) 13

INTRODUCTION

This appeal concerns the decision of the Public Service Commission of South Carolina (the "Commission") to grant a Certificate of Environmental Compatibility and Public Convenience and Necessity ("Certificate") for the construction and operation of a 750 megawatt ("MW") combined cycle natural gas-fired generating facility at Duke Energy Carolinas, LLC's ("DEC") existing Lee Steam Station near Anderson, South Carolina (the "Lee Gas Plant").

Appellants, the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy, have appealed the Certificate Order on two grounds, as set forth in their statement of issues on appeal and as discussed in their initial brief. First, when issuing the Certificate for the Lee Gas Plant, the Commission erred by failing to consider or require a solar component proposed by Appellants that would reduce the costs borne by customers, as well as air emissions and water use. Second, the Commission erred in finding that the Lee Gas Plant's environmental impact was justified, considering the state of available technology and the nature and economics of the various alternatives—specifically, Appellants' solar proposal—as required before granting a Certificate.

Respondents, DEC and its co-applicant the North Carolina Electric Membership Corporation ("NCEMC"), as well as the South Carolina Office of Regulatory Staff ("ORS"), which supported the Application, contend that the Commission did not err. Their basic contention is that the Commission was right to reject Appellants' proposal because that proposal sought to require DEC to construct more maximum energy generation capability (expressed as megawatts [MW] of "capacity") than is needed. But the record shows that Appellants' solar proposal, while expressed in terms of capacity,

was designed to yield a volume of electrical generation (expressed as megawatt-hours [MWhs] of "energy" or "power"), that could be used to complement and offset generation by the proposed natural gas facility. The Appellants did not propose to change the physical nature of the proposed combined cycle gas plant, or alter its maximum rated energy production capacity (750 MW). Instead, they proposed that the Commission condition the Certificate on the requirement that DEC issue a "request for proposals" ("RFP") for solar capacity up to a specified amount. According to Appellants' proposal, the MWhs generated by this solar capacity would offset MWhs that would otherwise need to be generated by the Lee Gas Plant to meet customer needs, and thus (by reducing the amount of gas burned) lessen that facility's environmental impact and reduce the cost to customers.

As discussed below, Respondents' arguments supporting the Commission's decision to reject Appellants' proposed solar condition do not remedy the legal error that occurred. At the end of the day, the Commission simply failed to actually consider a proposal put forth in the record that would reduce the Lee Gas Plant's environmental impact at no cost, and potentially some savings, to customers.

ARGUMENT

I. THE COMMISSION'S DECISION TO REJECT APPELLANTS' PROPOSED SOLAR CONDITION WAS ERRONEOUS AND NOT SUPPORTED BY SUBSTANTIAL EVIDENCE.

A. Because the Commission failed to consider the solar proposal actually put forth by Appellants, its rejection of the proposal was clearly erroneous in view of the record evidence.

Before issuing a Certificate, the Commission was required to "find and determine," among other things, that the Lee Gas Plant's environmental impact was "justified, considering the state of available technology and the nature and economics of the various alternatives and other pertinent considerations." S.C. Code Ann. § 58-33-160. The Commission has the authority to grant a Certificate "upon such terms, conditions or modifications . . . as the Commission may deem appropriate." *Id.*

Appellants recommended that the Commission condition its grant of the Certificate on a requirement that DEC issue a request for proposals ("RFP") for solar power. In essence, this would be an operating condition, such that if (and only if) solar bids came in at a price at or below the cost of generating energy from the Lee Gas Plant, DEC would use the solar to reduce operation of the gas plant commensurately, thereby reducing its emission of air pollution and its consumption of water from the Saluda River.

It is uncontested that Appellants' proposal would indeed reduce those environmental impacts, yet the Commission rejected the proposed condition, in contravention of its authority to impose economically feasible conditions and modifications to reduce environmental impacts. The Commission committed clear error in failing to undertake any meaningful review of the option put forth by Appellants, and by endorsing the utility's proposal with no independent analysis whatsoever.

Both DEC/NCEMC and ORS attempt to bolster the Commission's decision, with each side attacking from a different (and somewhat contradictory) angle. DEC/NCEMC argue that the Commission understood Appellants' solar proposal and properly rejected it, whereas ORS argues that Appellants did not clearly state their proposal in testimony before the Commission and, in fact, modified it after the hearing in a petition filed with the Commission and in their initial brief to this Court. An examination of the Commission's findings and the record evidence reveals that both DEC/NCEMC and ORS are wrong.

1. The Commission either ignored or misunderstood evidence submitted by Appellants, and therefore its decision was arbitrary and clearly erroneous in view of the record evidence.

Appellants explained their proposed solar RFP condition in testimony pre-filed with the Commission as well as in testimony at the hearing. The proposal is as follows. First, using its 30-year forecast of fuel and other variable costs for the Lee Gas Plant, DEC would develop a "benchmark" price at which customers would be indifferent to whether the electricity was generated by the Lee Gas Plant or a solar facility (or facilities). (Tr. Vol. 2, p. 199, lines 5-7; R. p. 318, lines 5-7.) Second, DEC would issue an RFP for up to 375 MW of solar capacity at or near the Lee site. (Tr. Vol. 2, p. 203, lines 6-12; R. p. 322, lines 6-12.) While expressed as an RFP for "capacity," the aim of the RFP and of the Appellants' proposal generally was to elicit bids for projects that could actually deliver megawatt-hours of energy to be used in lieu of megawatt-hours of energy from the proposed Lee Gas Plant. The goal was not to change the size or capacity of the plant proposed by DEC/NCEMC (it would still have a maximum potential output of 750 MW), but to provide energy that could enable the Lee Gas Plant to "ramp down" and reduce its production of electricity, and thus its consumption of gas and its pollution,

when it could be offset by solar generation. (Tr. Vol. 2, p. 181, lines 2-12; R. p. 300, lines 2-12.)

Importantly, DEC would only accept bids from solar developers if they came in *below* the benchmark price; *i.e.*, by definition, at a price lower than the long-term cost of operating the Lee Gas Plant to produce the same amount of power. (Tr. Vol. 2, p. 180, lines 20-24; R. p. 299, lines 20-24.) DEC/NCEMC claim that "the Commission's orders show it did understand the Appellants' solar proposal and that the Commission rejected it for compelling reasons." DEC/NCEMC Br., p. 11. ORS also asserts that the Commission did not misunderstand or misapply Appellants' position. But the Commission's order itself belies this claim. Indeed, the very same statements cited and/or quoted by DEC/NCEMC on page 12 of its brief, and by ORS on pages 11-12 of its brief, set forth below in bold font, show that the Commission either did not understand or apprehend the actual proposal before it, and that its summary rejection of Appellant's proposal was groundless. Said another way, the grounds given by the Commission for rejecting Appellants' proposal simply do not apply to Appellants' proposal.

- **"Solar energy has a much lower operating capacity factor due to its limited availability, making it not an optimal source for base or intermediate load."** (Order No. 2014-408, pp. 12-13; R. pp. 015-016.) This statement shows that the Commission fundamentally misapprehended Appellants' proposal. Appellants are well aware of the intermittent nature of solar—indeed, they cited a roughly 22% capacity factor for utility scale solar in the Southeast in testimony to the Commission (Tr. Vol. 2, p. 198, lines 13-15; R. p. 317, lines 13-15.) Appellants *did not*, however, propose that solar be built *instead of* the Lee Gas

Plant, *i.e.*, as a replacement intermediate or base load capacity resource. What Appellants proposed was using solar generation to *complement* production from the gas plant, so that available solar power could offset generation by the gas plant and consequently reduce its fuel costs and environmental impacts. (Tr. Vol. 2, p. 181, lines 2-12; R. p. 300, lines 2-12.)

- **"[T]he LCCP could not be built with lower than the [DEC] needed 650 MWs, since [DEC] has demonstrated a need for this additional capacity in the 2017-2018 time frame."** (Order No. 2014-408, p. 13; R. p. 016). Again, this shows the Commission was responding to something other than what Appellants proposed in the record. Appellants did not say that their solar component meant that DEC/NCEMC should build less natural gas capacity than that necessary to meet their claimed need.

- **"The reliability and operating capacity of the proposed solar facility is below the required need; therefore, it is not appropriate to meet the capacity needs of the proposed project."** Order No. 2014-408, p. 13; R. p. 016). Again, Appellants did not propose that DEC/NCEMC build less capacity than that necessary to meet their claimed need. Rather, Appellants proposed an RFP for solar capacity that would complement the Lee Gas Plant by producing energy that would enable reduction in generation from the gas plant (and thus reduction in its fuel and operating costs as well as environmental impacts). As Appellants' witness Hamilton Davis explained, the additional solar "is not a capacity need; it's an offset of costs associated with running Lee." (Tr. Vol. 2, p. 205, lines 5-7; R. p. 324, lines 5-7.) Had the Appellants actually proposed to reduce the capacity

of the Lee Gas Plant, there would be some indication of that in the record; for example, testimony opposing construction of the proposed 750 MW facility, or favoring construction of a smaller gas facility. But the record is devoid of any such recommendation.

- **"[A]ny MWs generated from solar would be in addition to the 650 MW capacity requirements."** (Order No. 2014-408, p. 13; R. p. 016.) This statement reveals a central reason that that the Commission failed actually to consider the Appellants' proposal—it conflated the concepts of generating capacity (a facility's maximum output, expressed in megawatts, or "MW") and energy production (also known as generation, expressed in megawatt-hours, or "MWh").[1] The MWh of energy that would be produced pursuant to the solar RFP would reduce the need to generate MWh from the Lee Gas Plant. As explained by Appellants' witness Davis, the solar RFP condition would allow "ramping down . . . [a] percentage of the operations" at the gas plant and "replacing that with the solar." (Tr. Vol. 2, p. 205, line 23-p. 206, line 1; R. p. 324, line 23-p. 325, line 1.)

- **"Based upon Duke's Integrated Resource Plan [which shows future planning for electricity needs], the additional 375 MW of solar capacity sought by [Appellants] are not needed at this time."** (Order No. 2014-408, p. 13; R. p. 016.) Again, this statement bespeaks a fundamental failure to actually consider the evidence and testimony that set forth the Appellants' proposal. While the proposed condition would *incidentally* provide some additional solar

[1] Footnote 1 in ORS' brief sets out the definitions of "capacity" and "generation" on the U.S. Energy Information Administration web site.

capacity, it was not proposed to meet the capacity need identified in DEC's IRP; rather, the thrust of the proposal is to provide energy (MWhs) to offset the need to generate energy from natural gas. As Witness Davis testified, "it's complementary capacity that would offset some of the operations of Lee and also potentially some of its costs." (Tr. Vol. 2, p. 205, lines 11-14; R. p. 324, lines 11-14.)

- **"We do not think it is good practice for this Commission to grant permission for the Company build or secure more capacity than is needed as this could ultimately result in customers paying more than necessary for electric service."** (Order No. 2014-408, p. 13; R. p. 016.) While true as a general principle of public utility regulation, this statement ignores a crucial aspect of Appellants' proposal, which is that to meet the RFP's requirements, a qualifying solar bid would have to meet or beat a benchmark price set at the long-term operating cost of the Lee Gas Plant. The Appellants' proposal, if it resulted in DEC taking any solar MWh at all, would by definition result in MWh equal or lower in price to the MWh they would displace from the Lee plant. As explained by Appellants' witness John D. Wilson: "Because the cost of a solar power component would be delivered at or below the benchmark, the incremental capital costs of the solar facility would be more than compensated for by the savings in the operating costs." (Tr. Vol. 2, p. 181, lines 8-12; R. p. 300, lines 8-12.)

2. ORS's claim that Appellants modified their solar RFP proposal after initially presenting it to the Commission is belied by the record.

ORS contends that Appellants' solar RFP condition was properly rejected by the PSC and should be ignored by this Court because Appellants did not fairly present their position to the Commission during the hearing, and modified their position in their Petition for Rehearing or Reconsideration and in their initial brief to this Court. ORS suggests that Appellants deliberately kept "an ace up their sleeve" in order to get "another bite at the apple." ORS Br., p. 13-14. The Commission's failure to acknowledge and evaluate Appellants' proposal has nothing to do with any gamesmanship by Appellants, and ORS's claims otherwise do not bear scrutiny.

According to ORS, Appellants have modified their position in two respects. First, ORS states, "[i]n its Petition for Rehearing, the Appellants state that the 375 MW solar RFP is not to be above and beyond the 750 MW, but instead the proposal is for solar to offset plant operating costs, when cost-effective to do so." ORS Br., pp. 12-13. The statement cited (but not quoted) by ORS actually reads:

> [T]he Order misapprehends the nature and intent of [Appellants'] solar recommendation as ***simply*** a request to require solar capacity above and beyond the capacity of the gas plant, when the proposal in fact is for solar to offset plant operating costs, when cost-effective to do so.

(Petition for Rehearing, p. 2; R. p. 089) (emphasis added). As explained above, this is an entirely accurate characterization of Appellants' proposal to the Commission. Yet the Commission nevertheless misunderstood the Appellants to be requesting additional generating capacity (*i.e.*, maximum energy production capability) for its own sake, rather than as complementary capacity that would produce fuel-free energy and reduce the need for energy production at the gas plant. A petition for rehearing, filed to alert an

adjudicator that it misunderstood a party's position, is hardly untoward; it is routine, and exactly why such petitions are allowed. *See* S.C. Code Ann. Regs. § 103-825(4) ("[a] Petition for Rehearing or Reconsideration shall set forth clearly and concisely: . . . [t]he *alleged error or errors* in the Commission order . . . .") (emphasis added).

ORS also claims that Appellants failed to plainly state their position that ratepayers would be "held harmless" under their proposal until their Petition for Rehearing. The record belies this as well. Appellants were careful to explain this aspect of the proposal—a crucial one—as clearly as they could. As Appellants' witness Davis testified:

> [DEC] would establish a benchmark price where it would be cheaper to enter into this contract for this solar capacity than it would be to run the natural gas plant . . . If that is not a wash or a net benefit to ratepayers, then Duke wouldn't move forward with that proposal. It would be triggered if the costs were neutral to ratepayers or a reduction in costs to ratepayers, so there's no risk on the front end, or back end, of this as we have proposed it.

(Tr. Vol 2, p. 205, line 20-p. 206, line 6; R. p. 324, line 20-p. 325, line 6.)

To the extent the Respondents were confused by Appellants' testimony, their counsel had an opportunity to cross-examine Appellants' witnesses at the evidentiary hearing before the Commission. They declined to ask a single question. (Tr. Vol. 2, p. 204, lines 1-9; R. p. 323, lines 1-9.)

The Commission, for its part, also largely chose to forgo the opportunity to seek clarification from Appellants' witnesses. Only one Commissioner asked any questions, and he asked only two. (Tr. Vol. 2, p. 204, line 19-p. 206, line 14:, R. p. 323, line 19-p. 325, line 14.) After Appellants' witnesses had left the stand, one Commissioner directed a question about Appellants' proposal to ORS witness Gene Soult, a Senior Research

Analyst with over 30 years' experience in the electric utility industry. This exchange followed:

> **Q** I wish I'd asked this question to the panel before, but you heard the testimony of Mr. Davis and Mr. Wilson.
> **A** I did.
> **Q** And when you were looking at this project, are there other projects that have been built similar to what they propose to do?
> **A** Yes, ma'am -- other projects as what Wilson and them have described?
> **Q** Uh-huh.
> **A** Not to my knowledge, dealing with the solar and the combined-cycle project -- is that what you're asking?
> **Q** Yes, I am.
> **A** I do not know of one, ma'am.

Tr. Vol. 2, pp. 218-19; R. pp. 337-78.[2] When counsel for Appellants offered to put Appellants' witnesses back on the stand to answer the question, the presiding Commissioner declined, but just after the hearing was adjourned the Hearing Officer granted leave to submit a late-filed exhibit with information responsive to the Commissioner's question. Appellants then submitted an exhibit summarizing several examples of solar projects that have been linked to natural gas generation in an effort to reduce fuel costs borne by customers, either co-located at the same site or as part of a utility resource portfolio. (Hrg. Ex. 7, Tr. Vol. 2, p. 221 [admitted]; R. pp. 340 [admitted], 617-19.) Although the exhibit was received into evidence, these examples were not mentioned in the Commission's order.

3. Conclusion

A decision by the Commission warrants reversal by this Court if, among other things, it was "clearly erroneous in view of the reliable, probative, and substantial

[2] Line numbers are missing from this portion of the transcript.

evidence on the whole record." S.C. Code Ann. § 1-23-380(5)(e). Although this standard of review is deferential, it "does not mean . . . the Court will accept an administrative agency's decision at face value without requiring the agency to explain its reasoning." *Porter v. S. Carolina Pub. Serv. Comm'n*, 333 S.C. 12, 21, 507 S.E.2d 328, 332 (1998).

Appellants' solar proposal was concededly a concept that had not previously been proposed to the Commission by other parties. But substantial evidence in the record supported Appellants' proposal, and the Commission was required to explain its reasoning for rejecting Appellants' solar proposal. *Porter*, 333 S.C. at 21, 507 S.E.2d at 332. The Commission's explanations show that it fundamentally misunderstood Appellants' testimony in support of their solar recommendation. Because the Commission's characterization of Appellants' recommendation was unsupported by the evidence, its decision to reject that recommendation was clearly erroneous in view of the substantial evidence in the record.

B. The Commission has authority to modify or condition a Certificate, and erred in failing to exercise that authority.

The Commission concluded, erroneously, that it lacked the authority to attach Appellants' proposed solar condition to the Certificate. ORS argues that the Commission did not err in declining to apply the Siting Act's modification clause, which authorizes the Commission to grant a Certificate "upon such terms, conditions or modifications . . . as the Commission may deem appropriate." S.C. Code Ann. § 58-33-160. In support of this contention, ORS points to the Commission's statement in the Certificate Order that it was "questionable whether this Commission can change the type of facility being requested by the Company." (Order No. 2014-408, p. 14; R. p. 017.)

Appellants did not seek to alter the Lee Gas Plant itself, however. As discussed in detail in Section I.A., above, Appellants did not propose that the facility for which the Applicants sought a Certificate—a 750 MW combined-cycle natural gas plant—be physically altered. Instead, their proposed solar RFP would complement the gas plant by reducing its need to operate and consequently its fuel costs and environmental impacts. (Tr. Vol. 2, p. 181, lines 2-12; R. p. 300, lines 2-12.) Thus, Appellants' solar proposal was aimed at reducing the Lee Gas Plant's operational costs and environmental impacts, in light of the Siting Act's requirement that a Certificate only be granted where the Commission finds that the facility's environmental impact "is justified, considering the state of available technology and the nature and economics of the various alternatives and other pertinent considerations." S.C. Code Ann. § 58-33-160(b), (c).

It is a well-recognized principle of public utility regulation that a commission may attach reasonable terms or modifications to the grant of a certificate:

> A public utilities commission may, in the public interest, annex reasonable conditions or limitations to a certificate of convenience and necessity. Such conditions must be within the express or implied power of the commission conferred by statute, but the commission has discretion to impose equitable conditions.

73B C.J.S. *Public Utilities* § 186 (2013). Consistent with this principle, the Siting Act empowers the Commission either to grant or deny the application for a Certificate as filed, or to grant it "upon such terms, conditions or modifications of the construction, operation or maintenance of the major utility facility as the Commission may deem appropriate." S.C. Code Ann. § 58-33-160. Our Supreme Court has explained that an administrative body such as the Commission has broad authority in discharging its statutory duties:

> Even a governmental body of admittedly limited powers is not in a strait jacket in the administration of the laws under which it operates. Those laws delimit the Field which the regulations may cover. They may imply or express restricting limitations of public policy. And of course they may contain express prohibitions. But in the absence of such limiting factors it is not to be doubted that such a body possesses not merely the powers which in terms are conferred upon it, but also such powers as must be inferred or implied in order to enable the agency to effectively exercise the express powers admittedly possessed by it.

Carolina Water Serv., Inc. v. S. Carolina Pub. Serv. Comm'n, 272 S.C. 81, 87, 248 S.E.2d 924, 927 (1978) (quoting *Beard-Laney, Inc. v. Darby*, 213 S.C. 380, 389, 49 S.E.2d 564, 567 (1948)) (holding Commission had implied authority to determine whether a water service fee was a tap fee or customer contribution in aid of construction for purposes of setting reasonable water service rate). The Siting Act thus confers wide latitude for the Commission to attach appropriate conditions to a Certificate, commensurate with its duty to examine economical alternatives that would minimize environmental harm. While that authority would indeed be broad enough to allow the Commission to insist on physical changes to a proposed facility, that is not what Appellants recommended. The Commission's failure to consider Appellants' proposed solar condition, citing a professed lack of authority, was clear legal error.

That error is not excused by Respondents' concerns about public notice requirements. They point to the Commission's concern that it is "questionable whether this would be permitted under the Siting Act given that such a grant of permission would be enlarging the scope of the Application without notice to the public." Order No. (Order No. 2014-408, pp. 13-14; R. pp. 016-017.) While Appellants certainly appreciate and support the need to provide proper notice to public, the concern here rests on a misstatement of Appellants' proposal, and the Commission's own procedures provide a

clear path to providing public notice of any solar facilities constructed or power purchased pursuant to the RFP proposed by Appellants.

Appellants only recommended that Commission condition its grant of a Certificate on DEC's issuance of the RFP. As discussed in detail in Section I.A., it is not a foregone conclusion that DEC would accept any solar bids submitted in response to its RFP, because it would only accept bids that could meet the benchmark price. The RFP process would unfold, and any solar facilities that DEC selected pursuant to the RFP would need to go through appropriate regulatory proceedings, including public notice if applicable. Moreover, the Siting Act does not preclude the Commission from requiring an applicant to re-notice an application that has been granted subject to conditions or modifications. S.C. Code Ann. § 58-33-160(2). The Siting Act thus provides established public notice procedures. If the Commission had determined that the solar RFP condition would require additional public notice, the Siting Act authorized it to require or condition its granting of the application on such further notice. The concern about public notice is simply a red herring.

II. THE COMMISSION'S FINDING THAT THE LEE GAS PLANT'S ENVIRONMENTAL IMPACT WAS JUSTIFIED WAS INSUFFICIENTLY DETAILED AND NOT SUPPORTED BY SUBSTANTIAL EVIDENCE.

Before issuing a Certificate, the Commission was required to "find and determine," among other things, "the nature of [the facility's] probable environmental impact," and that this impact "is justified, considering the state of available technology and the nature and economics of the various alternatives and other pertinent considerations." S.C. Code Ann. § 58-33-160(b), (c). As explained in Appellants' initial brief, the Commission failed to make specific, detailed findings regarding the facility's environmental impact and the ability of available alternatives to reduce this impact, in

contravention of the Siting Act's requirements. Instead, the Commission merely repeated in summary form the favorable testimony of DEC and ORS witnesses regarding the Lee Gas Plant's general environmental attributes, with no acknowledgment—let alone detailed discussion—of conflicting testimony in the record about the plant's air pollution emissions and water consumption. In addition, as discussed in detail in Section I.A., above, the Commission ignored or misunderstood much of Appellants' testimony regarding their solar proposal, and as a result, the Commission's findings regarding alternatives were not supported by substantial evidence.

Respondents counter that the Commission's findings regarding the environmental impact of the Lee Gas Plant were adequate and supported by substantial evidence, pointing to evidence that they claim supported the Commission's findings, emphasizing the page count of the Application and providing citations to testimony by the Lee Gas Plant's proponents regarding its asserted minimal environmental impacts. While ORS acknowledges the existence of testimony regarding negative environmental impacts, the Respondents can provide no citation to any discussion of this conflicting evidence by the Commission in its order—because there is none. The record, in fact, shows that the Commission ignored this conflicting evidence entirely.

ORS quibbles that the testimony about negative environmental impacts was elicited through cross-examination rather than presented by Appellants' witnesses.[3] In fact, the pre-filed direct testimony of DEC's own witness Mark E. Landseidel discussed pollution emissions from the Lee Gas Plant, including nitrogen oxides ("NOx"), carbon monoxide and volatile organic compounds. (Tr. Vol. 2, p. 157, line 20-p. 158, line 2; R.

[3] ORS states that "Appellants' testimony did not discuss pollutants, but discussed emissions in the context of a solar facility having lower emissions than the proposed plant." ORS Br., p. 16. This is pure semantics, as "pollutants" and "emissions" are different ways of saying the same thing.

p. 276, line 20-p. 277, line 2.) Mr. Landseidel also testified that the Lee Gas Plant would consume an estimated 10 cubic feet per second of water from the Saluda River, which is a drinking water source. (Tr. Vol. 2, p. 159, lines 11-13; R. p. 278, lines 11-13.) On cross-examination, Mr. Landseidel agreed that operating the unit at a lower output would reduce water use. (Tr. Vol. 2, p. 166, line 23; R. p. 285, line 23.) He also conceded that operations at lower power would reduce emission of air pollution such as NOx. (Tr. Vol. 2, p. 167, line 18; R. p. 286, line 18.) The Commission was made aware that the Lee Gas Plant will have some negative environmental effects, and was presented with a proposal to reduce them, yet its Certificate Order failed to acknowledge these environmental impacts, let alone discuss them in detail.

Respondents emphasize the deference to be accorded the Commission under the substantial evidence standard; however, that does not end the inquiry. The Commission's findings "must be sufficiently detailed to enable the reviewing court to determine whether the findings are supported by the evidence and whether the law has been properly applied to those findings." *Able Commc'ns, Inc. v. S. Carolina Pub. Serv. Comm'n*, 290 S.C. 409, 411, 351 S.E.2d 151, 152 (1986). As is the case here, "[w]here material facts are in dispute, the administrative body must make specific, express findings of fact," *Kiawah Prop. Owners Grp. v. Pub. Serv. Comm'n of S. Carolina*, 338 S.C. 92, 96, 525 S.E.2d 863, 865 (1999), and "a recital of conflicting testimony followed by a general conclusion is patently insufficient to enable a reviewing court to address the issues," *Able Commc'ns, Inc.*, 290 S.C. at 411, 351 S.E.2d at 152, the Commission did not even acknowledge conflicting testimony. Instead, it merely summarized the proponents' favorable testimony regarding the proposed facility's positive environmental attributes

and made a general conclusion without even discussing testimony by the same witnesses acknowledging the negative impacts of the facility or attempting to resolve any factual differences about those impacts. The Commission's findings regarding the Lee Gas Plant's environmental impacts were one-sided, generalized, and patently insufficient. Its Certificate Order should be reversed, and the matter remanded for proper evaluation.

CONCLUSION

For the foregoing reasons, Appellants respectfully request that the Court reject the arguments made by Respondents, reverse the Commission's grant of a Certificate to DEC and NCEMC, and remand this matter to the Commission.

Respectfully submitted this 12th day of March, 2015.

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THE STATE OF SOUTH CAROLINA
In the Court of Appeals

Appellate Case No. 2014-001514

APPEAL FROM THE PUBLIC SERVICE COMMISSION

Docket No. 2013-392-E

In The Matter of Joint Application of Duke Energy Carolinas, LLC and North Carolina Electric Membership Corporation for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of a 750MW Combined Generating Plant Near Anderson, SC

CERTIFICATE OF COMPLIANCE WITH RULE 211(b)

I certify that the foregoing Final Reply Brief of Appellants South Carolina Coastal Conservation League and Southern Alliance for Clean Energy complies with Rule 211(b), SCACR.

Gudrun Thompson

THE STATE OF SOUTH CAROLINA
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CERTIFICATE OF SERVICE

I certify that I have served the Final Reply Brief of Appellants South Carolina Coastal Conservation League and Southern Alliance for Clean Energy on all parties by depositing a copy in the United States Mail, postage prepaid, on March 12, 2015, addressed to their attorneys of record, as indicated below:

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FINAL BRIEF OF APPELLANTS SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND SOUTHERN ALLIANCE FOR CLEAN ENERGY

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STATEMENT OF ISSUES ON APPEAL

1. Whether the Public Service Commission of South Carolina ("Commission") erred by failing to consider or require a solar component when issuing a Certificate of Environmental Compatibility and Public Convenience and Necessity for a proposed natural gas combined cycle power plant?

2. Whether the Commission erred in finding that the gas plant's environmental impact was justified, considering the state of available technology and the nature and economics of the various alternatives to reduce impacts and save ratepayers money?

STATEMENT OF THE CASE

This matter comes before the Court on appeal from a decision by the Public Service Commission of South Carolina (the "Commission") to grant a Certificate of Environmental Compatibility and Public Convenience and Necessity ("Certificate") to Duke Energy Carolinas, LLC ("DEC") and the North Carolina Electric Membership Corporation ("NCEMC") for the construction and operation of a 750 megawatt ("MW") combined cycle natural gas-fired generating facility at DEC's existing Lee Steam Station near Anderson, South Carolina (the "Lee Gas Plant").

On October 24, 2013, DEC and NCEMC filed a joint Application for a Certificate under the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. § 58-33-10, *et seq.* The application included a certification that DEC had served a copy of the application on those governmental officials and such other persons as S.C. Code Ann. § 58- 33-120(2) requires.

By letter dated November 1, 2013, the Clerk's Office of the Commission required DEC to publish a prepared Notice of Filing and Hearing which described the nature of the Application and advised all interested parties of the manner in which they might intervene or otherwise participate in the proceeding. DEC submitted an affidavit which demonstrated compliance with the Clerk's instructions. Statutory parties were the South Carolina Office of Regulatory Staff ("ORS"), the South Carolina Department of Health and Environmental Control ("DHEC"), the South Carolina Department of Natural Resources ("DNR") and the South Carolina Department of Parks, Recreation, and Tourism (the "Department"). Petitions to intervene were filed by the South Carolina Coastal Conservation League ("CCL") and Southern Alliance for Clean Energy ("SACE"); Invenergy Thermal Development, LLC ("Invenergy"); and the Electric

Cooperatives of South Carolina, Inc. and Central Electric Power Cooperative, Inc. (the "Co-ops"). The Co-ops filed a request to withdraw their petition to intervene, which was granted by the Commission on December 18, 2013. Also on December 18, 2013, the Commission denied Invenergy's petition to intervene upon objection by DEC and NCEMC. On January 2, 2014, Invenergy renewed its petition to intervene. A Settlement Agreement between DEC, NCEMC and ORS was filed on January 3, 2014.

On January 7, 2014, in accordance with Section 58-33-130 of the Siting Act and with the Commission's Rules of Practice and Procedure, the Commission commenced an evidentiary hearing on the Certificate application. On the oral motion of DEC, NCEMC and ORS, the Commission moved those parties' Settlement Agreement into the record. The Commission also denied Invenergy's renewed petition to intervene. The Commission then recessed the hearing.

The Commission reconvened the evidentiary hearing on February 4, 2014. DEC presented the testimony of Clark S. Gillespy, Janice D. Hager and Mark E. Landseidel. NCEMC presented the testimony of Michael W. Burnette, which was stipulated into the record. CCL and SACE presented the joint testimony of T. Hamilton Davis IV and John D. Wilson. ORS presented the testimony of Gene G. Soult. DHEC, DNR and the Department did not participate in the hearing.

On May 2, 2014, the Commission issued its Order Granting a Certificate of Environmental Compatibility and Public Convenience and Necessity to DEC and NCEMC for the Lee Gas Plant. Appellants filed a petition for rehearing on May 15, 2014. On June 4, 2014, the Commission voted to deny Appellants' petition and issued a written directive to that effect. Appellants filed a Notice of Appeal on July 3, 2014. The

Commission issued an Order Denying Petition for Rehearing and Reconsideration on July 30, 2014.

STATEMENT OF FACTS

The proposed Lee Gas Plant is a 750 MW natural gas-fired combined cycle electrical generating plant to be constructed at the site of DEC's existing Lee Steam Station in Anderson County, South Carolina. (Order No. 2014-408, p. 1; R. p. 004.) DEC is a limited liability company, organized under the laws of the State of North Carolina, which supplies retail electric service to approximately 2.4 million customers in its service area, including approximately 540,000 customers in South Carolina. NCEMC is a generation and transmission cooperative, a not-for-profit membership corporation under North Carolina, whose membership cooperatives use power supplied by NCEMC to provide retail electric service to their customers. (Order No. 2014-408, p. 6; R. p. 009.)

DEC declined to disclose publicly an estimated construction cost for the proposed Lee Gas Plant, which was filed under seal. (Tr. Vol. 2, p. 98, lines 23-24; R. p. 217, lines 23-24.) The construction cost of a similar combined cycle project recently completed at DEC's Dan River plant, however, was approximately $673 million. (Tr. Vol. 2, p. 167, line 21-p. 168, line 3; R. p. 286, line 21-p. 287, line 3.) The Lee Gas Plant is only the first of four to five natural gas combined-cycle ("NGCC") plants that DEC and fellow Duke Energy subsidiary Duke Energy Progress plan to construct over the next decade. (Tr. Vol. 2, p. 193, lines 1-4; R. p. 312, lines 1-4.) Together, construction of these plants will cost ratepayers billions of dollars.

Although expensive to build, NGCC plants are even more expensive to run. Operating costs, mainly the natural gas burned as fuel, would constitute 80-90 percent of

the Lee Gas Plant's long-term cost to ratepayers. (Tr. Vol. 2, p. 197, lines 7-9; R. p. 316, lines 7-9.) Approximately 30 percent of the operating costs of DEC's share of the unit will be allocated to South Carolina ratepayers. (Tr. Vol. 2, p. 42, line 21-p. 43, line 3; R. p. 161, line 21-p. 162, line 3.) Natural gas prices, while currently lower than in the past, have historically been subject to significant price volatility, and are also subject to supply disruptions from natural disasters. (Tr. Vol. 2, p. 117, lines 11-16; R. p. 236, lines 11-16.) If natural gas prices increase, South Carolina customers will pay more for electricity produced by the plant. (Tr. Vol. 2, p. 117, line 25-p. 118, line 4; R. p. 236, line 25-p. 237, line 4.)

The Siemens F Class technology proposed for the Lee Gas Plant has demonstrated operational flexibility including multiple starts, minimum load capability and minimum start times. (Tr. Vol. 2, p. 154, lines 1-3; R. p. 273, lines 1-3.) The technology and configuration selected by DEC provide significant capability to ramp the plant up and down quickly, as well as come to relatively low minimum loads. (Tr. Vol. 2, p. 163, lines 19-23; R. p. 282, lines 19-23.) DEC witness Landseidel testified that "the intermediate capability of the plant allows it to fluctuate as needed to meet the system needs," which could vary for reasons "including intermittent power sources," such as solar. (Tr. Vol. 2, p. 166, lines 5-8; R. p. 285, lines 5-8.) Mr. Landseidel testified that operating at lower output would not decrease the facility's useful life, since the plant is designed with the capability for cycling and operation at minimum loads, (Tr. Vol. 2, p. 165, lines 7-13; R. p. 284, lines 7-13).

Given the ability of a combined cycle plant to operate efficiently at variable levels, natural gas combined-cycle technology pairs well with solar generation, a

dependable and fuel-free but variable power source. To reduce the environmental impacts and offset the operating costs of the Lee Gas Plant, Appellants recommended that the Certificate for the project be conditioned on a requirement that DEC issue a request for proposals ("RFP") for cost-effective solar power. The RFP would be developed as follows. First, DEC would develop a benchmark price using the 30-year forecast of the variable costs for the Lee Gas Plant (mainly, natural gas). This is the price at which customers would be indifferent to whether the electricity was generated by the Lee Gas Plant or a solar facility (or facilities). (Tr. Vol. 2, p. 199, lines 5-7; R. p. 318, lines 5-7.) Second, DEC would issue an RFP for up to 375 MW of firm solar power at the benchmark price. (Tr. Vol. 2, p. 203, lines 6-9; R. p. 322, lines 6-9.) Bids would only be accepted if they came in below the benchmark price; i.e., by definition, at a price lower than the long-term cost of operating the Lee Gas Plant to produce the same amount of power. (Tr. Vol. 2, p. 180, lines 20-24; R. p. 299, lines 20-24.)

By its terms, the solar condition proposed by CCL and SACE would not add costs for ratepayers. Moreover, the solar component would provide a significant hedge against gas price upside volatility; it would, as Mr. Davis testified, "save ratepayers money if solar costs go down and gas prices go up." (Tr. Vol. 2, p. 180, line 24-p. 181, line 1; R. p. 299, line 24-R. p. 300, line 1.) DEC witness Janice D. Hager agreed that instead of dispatching the natural gas plant, the Company could dispatch a type of generating facility that had lower fuel costs. (Tr. Vol. 2, p. 118, lines 9-12; R. p. 237, lines 9-12.) Solar, of course, has zero fuel costs. (Tr. Vol. 2, p. 118, lines 13-14; R. p. 237, lines 13-14.)

Solar's potential to offset part of the fuel costs of natural gas facilities and hedge against gas price increases has led to a growing trend of gas-solar pairings across the nation. Appellants submitted evidence regarding several solar projects that have been linked to natural gas generation, either co-located at the same site or as part of a resource portfolio. (Hrg. Ex. 7, Tr. Vol. 2, p. 221 [admitted]; R. pp. 340 [admitted], 617-19.) For example, Xcel Energy has proposed a wind/solar/gas proposal that would reduce operating costs by $246 million. (Hrg. Ex. 7, Tr. Vol. 2, p. 221 [admitted]; R. p. 340 [admitted], 618.) Florida Power & Light ("FPL") has a hybrid facility in which a 75 MW solar thermal power plant is directly connected to a 1,142 MW combined-cycle natural gas power plant at FPL's Martin Plant. *Id.* FPL has explained the Martin hybrid facility is a "fuel-substitute facility" that "displaces the use of fossil fuel," and is "not a facility that provides additional capacity and energy." *Id.* Similarly, in a competitive bidding process overseen by the Minnesota Public Utilities Commission, the Administrative Law Judge found that "[Xcel Energy's] solar project has no associated fuel costs, and, therefore, provides for a fixed and certain price for the life of the project." *Id.* Finally, Louisville Gas and Electric Company and Kentucky Utilities Company recently submitted a joint application to the Kentucky Public Service Commission for certificates of public convenience and necessity for the construction of both a natural gas combined cycle facility and a solar photovoltaic facility, having concluded after a request for proposals process that the gas-solar combination was the "least-cost reasonable alternative for meeting customer needs." (Hrg. Ex. 7, Tr. Vol. 2, p. 221 [admitted]; R. p. 340 [admitted], 619.)

The proposed Lee Gas Plant, while less polluting than the coal units it would replace, would still emit air pollutants such as nitrogen oxides and carbon dioxide. (Tr. Vol. 2, p. 39, lines 1-4; R. p. 158, lines 1-4.) The plant would also consume an estimated 10 cubic feet per second of water from the Saluda River, which is a drinking water source. (Tr. Vol. 2, p. 159, lines 11-13; R. p. 278, lines 11-13.) At the evidentiary hearing, DEC witness Landseidel conceded that operating the unit at a lower output would reduce water use (Tr. Vol. 2, p. 166, lines 20-23; R. p. 285, lines 20-23), as well as emissions of air pollutants (Tr. Vol. 2, p. 167, lines 12-18; R. p. 286, lines 12-18).

STANDARD OF REVIEW

I. THE COMMISSION'S REVIEW OF THE CERTIFICATE APPLICATION.

The Utility Facility Siting and Environmental Protection Act ("Siting Act"), S.C. Code Ann. § 58-33-10, *et seq.*, governs the siting of electric utility facilities in South Carolina. The statute requires the Commission to render a decision upon the record either granting or denying the application for a Certificate as filed, or granting it upon such terms, conditions or modifications of the construction, operation or maintenance of the major utility facility as the Commission may deem appropriate. S.C. Code Ann. § 58-33-160.

The Commission may not grant a certificate for the construction, operation and maintenance of a major utility facility, either as proposed or as modified by the Commission, "unless it shall find and determine," among other things, "the nature of [the facility's] probable environmental impact," and that this impact "is justified, considering the state of available technology and the nature and economics of the various alternatives and other pertinent considerations." S.C. Code Ann. § 58-33-160(b), (c). The

Commission must also find that the facility "will serve the interests of system economy and reliability." *Id.* § 58-33-160(d).

II. THIS COURT'S REVIEW OF THE COMMISSION'S DECISION.

Under the Siting Act, any party may appeal from all or any portion of any final order or decision of the Commission. S.C. Code Ann. § 58-33-310. Such appeal is in accordance with S.C. Code Ann. § 1-23-380, the statute governing judicial review of a final decision in a contested case. That section provides that the appellate court may not substitute its judgment for the judgment of the Commission as to the weight of the evidence on questions of fact. *Id.* § 1-23-380(5). The court may reverse or modify the decision if substantial rights of the appellant have been prejudiced because the administrative findings, inferences, conclusions, or decisions are:

(a) in violation of constitutional or statutory provisions;

(b) in excess of the statutory authority of the agency;

(c) made upon unlawful procedure;

(d) affected by other error of law;

(e) clearly erroneous in view of the reliable, probative, and substantial evidence on the whole record; or

(f) arbitrary or capricious or characterized by abuse of discretion or clearly unwarranted exercise of discretion.

Id.

South Carolina appellate courts employ a deferential standard of review when reviewing a decision of the Commission, and will affirm that decision when substantial evidence supports it. *Porter v. S. Carolina Pub. Serv. Comm'n*, 333 S.C. 12, 20, 507 S.E.2d 328, 332 (1998). The party challenging a Commission decision bears the burden

of convincingly proving that the decision is clearly erroneous, or arbitrary or capricious, or an abuse of discretion, in view of the substantial evidence on the whole record. *Heater of Seabrook, Inc. v. Pub. Serv. Comm'n of South Carolina*, 324 S.C. 56, 60, 478 S.E.2d 826, 828 (1996).

"This deferential standard of review does not mean, however, that the Court will accept an administrative agency's decision at face value without requiring the agency to explain its reasoning. "*Porter v. S. Carolina Pub. Serv. Comm'n,* 333 S.C. 12, 21, 507 S.E.2d 328, 332 (1998). "The findings of fact of an administrative body must be sufficiently detailed to enable the reviewing court to determine whether the findings are supported by the evidence and whether the law has been properly applied to those findings." *Able Commc'ns, Inc. v. S. Carolina Pub. Serv. Comm'n*, 290 S.C. 409, 411, 351 S.E.2d 151, 152 (1986). "Where material facts are in dispute, the administrative body must make specific, express findings of fact." *Kiawah Prop. Owners Grp. v. Pub. Serv. Comm'n of S. Carolina*, 338 S.C. 92, 96, 525 S.E.2d 863, 865 (1999). Although no particular format is required, "a recital of conflicting testimony followed by a general conclusion is patently insufficient to enable a reviewing court to address the issues." *Able Commc'ns, Inc. v. S. Carolina Pub. Serv. Comm'n*, 290 S.C. 409, 411, 351 S.E.2d 151, 152 (1986).

ARGUMENT

Appellants respectfully submit that the Certificate was not granted in compliance with the Siting Act's requirement that the Commission only grant a certificate for a major utility facility, "as proposed or as modified by the Commission," where it determines the facility's "probable environmental impact" is "justified" considering "available technology and the nature and economics of the various alternatives and other pertinent

considerations." S.C. Code § 58-33-160(c). As described above, Appellants submitted evidence showing that a solar energy component would materially reduce the proposed gas facility's environmental impact and cost to customers. The Commission failed to actually consider or make statutorily required findings in light of this evidence. The Commission's rejection of Appellants' solar recommendation springs from three central errors, as discussed in the following sections.

I. BECAUSE THE COMMISSION FUNDAMENTALLY MISAPPREHENDED APPELLANTS' SOLAR RECOMMENDATION, ITS DECISION TO REJECT THAT RECOMMENDATION WAS CLEARLY ERRONEOUS.

First, the Commission misapprehended Appellants' solar recommendation itself, in several respects, and inaccurately characterized the proposal in its orders. Because the Commission fundamentally misunderstood Appellants' solar recommendation, it did not carry out its duty to determine that the gas facility's impact "is justified, considering the state of available technology and the nature and economics of the various alternatives and other pertinent considerations." S.C. Code Ann. § 58-33-160(b), (c).

The Commission apparently understood Appellants to recommend that the Commission issue a Certificate for *less natural gas generating capacity* than that proposed by the applicants, and rejected that recommendation because "the [Lee Gas Plant] could not be built with lower than the Company-needed 650 MWs . . . ." (Order No. 2014-408, p. 13; R. p. 016). In addition, the Commission reasoned that "solar will not be capable of providing the intermediate to base load needs of the Lee Facility." (Order No. 2014-546, p. 4; R. p. 031.) Appellants did not propose that a certificate be issued for less than 650 MW, however, or suggest that their proposed solar component proposal would suffice to meet DEC's capacity need. Instead, they recommended that

DEC procure cost-effective solar generation that would offset the operating costs of the gas plant by reducing the amount of fuel burned. By way of illustration, if DEC obtained 300 MW of solar, on a sunny day it could use solar energy to displace the amount of energy that the natural gas plant would have to produce by burning natural gas. Because the RFP would guarantee that energy from solar generation would be no more expensive (if not less expensive) than the cost of energy from the Lee Gas Plant, this hybrid arrangement would present only benefits to ratepayers.

The Commission's conception of the solar component as adding capacity—i.e., that "any MWs generated from solar would be in addition to the 650 MW capacity requirements" (Order No. 2014-546, p. 3; R. p. 030)—and its view that Appellants merely sought to force construction of electrical generation capacity above and beyond the Lee Gas Plant's capacity (Order No. 2014-408, p. 13; R. p. 016), was thus error. Appellants presented evidence that requiring Duke to issue a RFP for solar power that, as delivered, would displace production at the Lee Gas Plant (megawatt hours, or MWh) and reduce fuel burned there. Much as the electrical component of a hybrid car operates in tandem with the gas motor, the solar component would complement gas production, not be in addition to it.

The Commission's misconception also led it to claim—with no evidentiary basis—that because "capital investment would be needed to build the solar facility," the proposal "could ultimately result in customers paying more than necessary for electric service." (Order No. 2014-408, p. 13; R. p. 016.) Again, these statements reflect a disregard for the key criterion in Appellants' recommendation: that DEC would only accept solar bids at a benchmark price at or below the operating costs of the gas unit, so

that customers would necessarily be held harmless or even benefit. Said another way, because bids would only be accepted if they were equal to or lower than a benchmark price based on the long-term operating costs of the gas facility, qualifying bids would, by definition, provide energy at or below the cost of producing the same energy from the Lee Gas Plant. By using solar electricity procured through the RFP, DEC could reduce production at the Lee Gas Plant, saving on fuel and other operating costs. Thus, the solar modification could at worst only save ratepayers money and provide a conservative hedge given gas price volatility.

South Carolina law requires the Commission to explain its reasoning for rejecting Appellants' solar proposal. *Porter*, 333 S.C. at 21, 507 S.E.2d at 332. The Commission's explanations show that it fundamentally misunderstood Appellants' testimony in support of their solar recommendation. Because the Commission's characterization of Appellants' recommendation was unsupported by the evidence, its decision to reject that recommendation was clearly erroneous in view of the substantial evidence in the record.

II. THE COMMISSION ERRONEOUSLY FOUND THAT THE LEE GAS PLANT'S ENVIRONMENTAL IMPACT WAS JUSTIFIED.

Under the Siting Act, a Certificate for the Lee Gas Plant could only be issued, "as proposed or as modified by the Commission" where the Commission has determined, based on substantial evidence, that the facility's "probable environmental impact" is "justified" considering "available technology and the nature and economics of the various alternatives and other pertinent considerations." S.C. Code Ann. § 58-33-160(b)-(c). At a minimum, then, the Commission must make specific findings regarding the facility's

environmental impact and the ability of available alternatives to reduce this impact, which it did not do here.

The Commission was required by the Siting Act to find and determine "the nature of [the facility's] probable environmental impact." S.C. Code Ann. § 58-33-160(b). This it did not do. Instead, the Commission summarized the favorable testimony of the witnesses for DEC and the Office of Regulatory Staff, but wholly ignored conflicting testimony in the record showing that the Lee Gas Plant would emit air pollutants and also consume large amounts of water—environmental impacts that would be reduced by inclusion of a solar component that would reduce the facility's gas combustion, air pollutants and water consumption.

Beyond actually assessing probable environmental impacts, the Commission was also required to find and determine that the environmental impact of the plant "is justified, considering the state of available technology and the nature and economics of the various alternatives and other pertinent considerations." S.C. Code Ann. § 58-33-160(c). Notably, in 2002, the Commission denied a certificate for a similarly designed gas plant in the upstate after determining that it could not make a "finding that the impact of the facility upon the environment is justified." *In re Greenville County Power, LLC*, Docket No. 2001-411-E, Order No. 2002-120 (Denying Application for a Certificate of Environmental Compatibility and Public Convenience and Necessity) at 5 (April 1, 2002). In particular, despite the testimony of several company witnesses in that matter, the Commission found that given the absence of adequate air quality modeling, it could not assess the effect of the plant on air quality, as the law required. *Id.* The Commission also found that the combined cycle gas plant proposed in that case (and similar to the one

proposed in this case) would consume "large quantities of water" compared to another type of gas plant, a simple cycle peaking turbine. *In re Greenville County Power, LLC*, Docket No. 2001-411-E, Order No. 2002-377 (Denying Reconsideration) at 8 (May 17, 2002). In the absence of "detailed studies of the effects" of the plant's water consumption on the subject river's aquatic habitat and its environs, the Commission determined it could not "make the proper statutory findings as to the justifiability of the impacts of the plant on the environment." Order No. 2002-377 at 5; *id.* at 12 (without information on withdrawal's downstream impacts, Commission "could not make the required statutory finding" that impacts were justified). The Commission also held, correctly, that it is not bound by the findings of the Department of Health and Environmental Control ("DHEC"), since the Siting Act requires the Commission to make independent findings in issuing a Certificate. Order No. 2002-377 at 15.

As the Commission's order in the *Greenville County Power* docket makes clear, to fulfill its statutory obligation to determine that the Lee Gas Plant's environmental impact is "justified," the Commission must actually, and fully, consider the project's environmental impacts. It must also consider "alternatives" and options for "modif[ying]" the facility to reduce those impacts. Where, as here, alternative technology is available to reduce the project's environmental impact with no increased cost to ratepayers or effects on reliability, that impact is not "justified," as required by S.C. Code Ann. § 58-33-160(c). By reducing electricity generated from natural gas when the sun is shining, the solar component recommended by Appellants would reduce the gas plant's environmental impact almost by definition, since it is uncontested that solar

power produces no air pollution emissions and consumes no water from area streams or rivers.

At base, and as required by the Siting Act, Appellants' solar recommendation would reduce the facility's impact on the environment to a level "justified, considering the state of available technology and the nature and economics of the various alternatives and other pertinent considerations," while serving "the interests of system economy and reliability." S.C. Code Ann. § 58-33-160(c), (d). The Commission fundamentally misunderstood the solar modification proposed by Appellants. Without the proposed solar component, substantial evidence does not support a finding that the Lee Gas Plant's impact on the environment is "justified, considering the state of available technology and the nature and economics of the various alternatives and other pertinent considerations." S.C. Code Ann. § 58-33-160(c).

III. THE COMMISSION ERRONEOUSLY CONCLUDED THAT IT LACKED AUTHORITY TO IMPOSE APPELLANTS' RECOMMENDED CONDITION ON ISSUANCE OF THE CERTIFICATE.

The Commission also apparently felt itself bound to reject Appellants' solar proposal because it would "materially change" DEC's application and change the "type of facility" being requested. (Order 2014-408 at 14; R. p. 017.) In its Order Denying Rehearing, the Commission explained that "requiring DEC or another entity to construct a major solar facility at or near the Lee Project site . . . would substantially alter DEC and NCEMC's Application." (Order No. 2014-546 at 5; R. p. 032.) This conclusion was erroneous, for two reasons.

First, Appellants did not seek to alter DEC's basic proposal, which is to construct a combined cycle gas plant. Appellants' proposal would not require any change in the Lee Gas Plant's design. Indeed, DEC's own experts testified that its planned facility can

ramp up and down quickly and operate at reduced loads without impacts on reliability or efficiency, making it well paired to intermittent resources like solar. (Tr. Vol. 2, p. 163, lines 19-23; R. p. 282, lines 19-23.) Rather than replace the facility that DEC proposed, the Appellants requested that the Certificate include a condition that would reduce gas consumption (and related pollution) to the extent that solar energy is available for the same cost or less.

The language of the Siting Act clearly authorizes the Commission to place conditions on the grant of a Certificate: "The Commission shall render a decision upon the record either granting or denying the application as filed, or granting it upon such *terms, conditions or modifications of the construction, operation or maintenance of the major utility facility as the Commission may deem appropriate*." S.C. Code Ann. § 58-33-160 (emphasis added). South Carolina case law on this point is sparse, but the general principle that public utilities commissions may attach reasonable terms or modifications to the grant of a certificate is widely recognized. "A public utilities commission has *great latitude to impose conditions* on its grant of a certificate of public convenience and necessity," although such conditions must be lawful and reasonable. 64 Am. Jur. 2d *Public Utilities* § 160 (2013) (emphasis added) (citing *Rheems Water Co. v. Penn. Public Utility Comm'n*, 620 A.2d 609 (Penn. 1993) and *Kansas Elec. Power Co-op, Inc. v. State Corp. Comm'n*, 683 P.2d 1235 (Kan. 1984)); 73B C.J.S. *Public Utilities* § 186 (2013) ("A public utilities commission may, in the public interest, annex reasonable conditions or limitations to a certificate of convenience and necessity. Such conditions must be within the express or implied power of the commission conferred by statute, but the commission has discretion to impose equitable conditions.") (citing *Riverton Val. Elec.*

Ass'n v. Pacific Power & Light Co., 391 P.2d 489 (Wyo. 1964); *West Penn Rys. Co. v. Penn. Public Utility Comm'n*, 15 A.2d 539 (Penn. 1940); *Miss. Public Service Comm'n v. Miss. Power & Light Co.*, 593 So. 2d 997 (Miss. 1991)).

Requiring DEC to solicit bids for cost-effective solar to reduce the Lee Gas Plant's gas consumption, fuel costs and environmental impacts is fully within the Commission's authority to issue a Certificate approving a facility "as modified" by the Commission. Indeed, just as the Commission has the power to deny a Certificate for a gas power plant outright because of water consumption impacts and air pollution, as it did in *Greenville County Power*, cited above, it doubtless has the authority to include water-conserving and air pollution-reducing characteristics as a condition of granting a Certificate. Further, because solar generation has no fuel costs, requiring that DEC implement a solar component is a prudent hedge against natural gas price volatility. Because Appellants proposed that DEC only be required to accept bids that came in below the long-term operating costs of the Lee Gas Plant, their proposed condition could only save ratepayers money. Conditioning the grant of a Certificate on such a condition is thus consistent with the Commission's duty to only certify a facility—either as proposed or "as modified"—where it finds that the facility "will serve the interests of system economy and reliability." S.C. Code Ann. § 58-33-160(d).

CONCLUSION

For the foregoing reasons, Appellants respectfully request that the Court reverse the Commission's grant of a Certificate to DEC and NCEMC, and remand this matter to the Commission.

Respectfully submitted this 12th day of March, 2015.

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THE STATE OF SOUTH CAROLINA
In the Court of Appeals

Appellate Case No. 2014-001514

APPEAL FROM THE PUBLIC SERVICE COMMISSION

Docket No. 2013-392-E

In The Matter of Joint Application of Duke Energy Carolinas, LLC and North Carolina Electric Membership Corporation for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of a 750MW Combined Generating Plant Near Anderson, SC

CERTIFICATE OF COMPLIANCE WITH RULE 211(b)

I certify that the foregoing Final Brief of Appellants South Carolina Coastal Conservation League and Southern Alliance for Clean Energy complies with Rule 211(b), SCACR.

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CERTIFICATE OF SERVICE

I certify that I have served the Final Brief of Appellants South Carolina Coastal Conservation League and Southern Alliance for Clean Energy on all parties by depositing a copy in the United States Mail, postage prepaid, on March 12, 2015, addressed to their attorneys of record, as indicated below:

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THE STATE OF SOUTH CAROLINA
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APPEAL FROM
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COUNTERSTATEMENT OF ISSUES PRESENTED

I. DID THE PUBLIC SERVICE COMMISSION ERR IN GRANTING THE CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AND PUBLIC CONVENIENCE AND NECESSITY?

II. ARE THE PUBLIC SERVICE COMMISSION'S FINDINGS SUPPORTED BY SUBSTANTIAL EVIDENCE?

STATEMENT OF THE CASE

This case is under the purview of the South Carolina Utility Facility Siting and Environmental Protection Act ("the Siting Act"), S.C. Code Ann. § 58-33-10 *et. seq.* (1976 and Supp. 2014). The South Carolina Coastal Conservation League ("CCL") and Southern Alliance for Clean Energy ("SACE") (collectively "the Appellants") appeal two orders issued by the Public Service Commission of South Carolina (the "Commission") in Docket No. 2013-392-E which granted Duke Energy Carolinas, LLC ("Duke Energy") and the North Carolina Electric Membership Corporation ("NCEMC") (collectively "the Applicants") a Certificate of Environmental Compatibility and Public Convenience and Necessity ("CECPCN") pursuant to the Siting Act. The CECPCN grants Duke Energy and NCEMC permission to construct and operate a 750 megawatt ("MW") combined cycle natural gas-fired generating plant near Anderson, South Carolina (the "Lee Unit," "Lee NGCC Unit," or "LCCP"). These orders, Order No. 2014-408 and Order No. 2014-546 ("the Orders"), were issued on May 2, 2014 and July 30, 2014, respectively.

The South Carolina Office of Regulatory Staff ("ORS") is a required party to the CECPCN proceeding ("CECPCN proceeding" or "certification proceeding") pursuant to S.C. Code Ann. §§ 58-4-10(B) (Supp. 2014) and 58-33-140(1)(b) (Supp. 2014). In addition, S.C. Code Ann. § 58-33-140(1)(b) requires other parties to the CECPCN proceeding; however, those parties did not have counsel file a Notice of Appearance and did not participate in discovery or the hearing. The Applicants, Appellants and ORS were the only active parties in the matter.

On January 3, 2014, ORS and the Applicants filed a Settlement Agreement wherein ORS endorsed the Application of Duke and NCEMC. The Appellants declined the opportunity to join the Settlement Agreement.

On January 7, 2014, the Commission convened a formal hearing on the Application. On May 2, 2014, the Commission issued Order No. 2014-408 granting the CECPCN and approving the Settlement Agreement. On May 15, 2014, the Appellants filed a Petition for Rehearing stating the CECPCN was not granted in compliance with the Siting Act. The Commission denied the Petition for Rehearing in Order No. 2014-546 dated July 30, 2014. This appeal of the Commission's orders ensued with ORS receiving the Notice of Appeal on July 7, 2014.

STATEMENT OF FACTS

On October 24, 2013, the Applicants filed an Application requesting a CECPCN pursuant to the Siting Act to build a 750 MW combined cycle natural gas-fired generating plant near Anderson, South Carolina. S.C. Code Ann. § 58-33-10 *et. seq.* (1976 and Supp. 2014). The Siting Act requires a CECPCN from the Commission prior to the construction of a major utility facility. S.C. Code Ann. § 58-33-110(1) (1976). A major utility facility is defined as (1) an electric generating plant and associated facilities designed for, or capable of, operation at a capacity of more than 75 MW or (2) an electric transmission line and associated facilities of a designed operating voltage of 125 kilovolts or more. S.C. Code Ann. § 58-33-20(2)(a) and (b) (1976 and Supp. 2014).

The Commission has exclusive jurisdiction to rule on Siting Act CECPCN applications. S.C. Code Ann. § 58-33-110(1) (1976). Before granting a CECPCN for the construction, operation and maintenance of a major utility facility, the Commission is

required to make six statutorily-mandated findings pursuant to S.C. Code Ann. § 58-33-160(1) (1976). Those findings concern:

A. The basis of the need for the facility. S.C. Code Ann. § 58-33-160(1)(a);

B. The nature of the probable environmental impact of the facility. S.C. Code Ann. § 58-33-160(1)(b);

C. Whether the impact of the facility upon the environment is justified, considering the state of available technology and the nature and economics of the various alternatives and other pertinent considerations. S.C. Code Ann. § 58-33-160(1)(c);

D. Whether the facilities will serve the interests of system economy and reliability. S.C. Code Ann. § 58-33-160(1)(d);

E. Whether there is reasonable assurance that the proposed facility will conform to applicable state and local laws and regulations issued thereunder, including any allowable variance provisions therein, except that the Commission may refuse to apply any local law or local regulation that is unreasonably restrictive. S.C. Code Ann. § 58-33-160(1)(e); and

F. Whether public convenience and necessity require the construction of the facility. S.C. Code Ann. § 58-33-160(1)(f).

Commission rules and regulation require all parties to pre-file written testimony prior to the hearing. S.C. Code Ann. § 58-3-140(D) and 10 S.C. Code Ann. Regs. 103-845.C. (2012). The Applicants included pre-filed written direct testimony with their Application in lieu of waiting to file their testimony on a later Commission-determined due date.

ORS is a required party to the CECPCN proceeding pursuant to S.C. Code Ann. §§ 58-4-10(B) (Supp. 2014) and 58-33-140(1)(b) (Supp. 2014). ORS is mandated to "represent the public interest of South Carolina before the commission." S.C. Code Ann. § 58-4-10(B) (Supp. 2014). The "public interest" is defined in S.C. Code Ann § 58-4-10(B) as a balancing of the:

> (1) concerns of the using and consuming public with respect to public utility services, regardless of the class of customer;
> (2) economic development and job attraction and retention in South Carolina; and
> (3) preservation of the financial integrity of the state's public utilities and continued investment in and maintenance of utility facilities so as to provide reliable and high quality utility services.

In addition to the Applicants and ORS, S.C. Code Ann. § 58-33-140(1) (Supp. 2014) of the Siting Act names the following parties to the CECPCN proceeding: (1) the South Carolina Department of Health and Environmental Control ("DHEC"), (2) the South Carolina Department of Natural Resources ("DNR"), (3) the South Carolina Department of Parks, Recreation and Tourism ("PRT"), (4) the chief executive officer of each municipality, and the head of each state and local government agency, charged with the duty of protecting the environment or of planning land use, in the area in the county in which any portion of the facility is set to be located if it has filed a notice of intervention as a party within thirty days after the date it was served with a copy of the Application, and (5) any domestic nonprofit organization, formed in whole or in part to promote conservation or natural beauty, to protect the environment, personal health, or other biological values, to preserve historical sites, to promote consumer interest, to represent commercial and industrial groups, or to promote the orderly development of the

area in which the facility is to be located. Accordingly, the Application along with the testimony included with it was served on (1) ORS, (2) DHEC, (3) DNR, (4) PRT, (5) South Carolina Department of Commerce, (6) South Carolina Department of Archives & History, (7) South Carolina Department of Transportation, (8) South Carolina Institute of Archaeology & Anthropology, (9) South Carolina Department of Forestry Commission, (10) the Mayor of the Town of Williamston, (11) the Mayor of the Town of West Pelzer, (12) the Mayor of the Town of Pelzer, (13) the Mayor of the City of Belton, (14) the Mayor of the City of Greenville, (15) the Chairman of the Anderson County Council, (16) Anderson County Planning & Community Development, (17) Anderson County Parks, Recreation & Tourism, (18) Williamston Town Administrator, (19) Belton City Administrator, (20) Greenville City Manager, (21) Pelzer Town Administrator, (22) West Pelzer Town Clerk, and (23) Anderson Town Administrator. (R. p. 48-49.) Among the 23 entities or persons that received service of the Application and the Applicants' pre-filed written direct testimony, only ORS filed a Notice of Appearance and participated in discovery and the hearing. The end result was that only ORS, Appellants, and the Applicants participated in the CECPCN proceeding.

Notice of the Application was published in five newspapers: (1) The Williamston Journal, (2) Anderson Independent Mail, (3) Belton News-Chronicle, (4) The Greenville News, and (5) Anderson Observer. An affidavit was filed with the Commission from each newspaper affirming the notice was published. (R. p. 50-56.)

On the Commission-issued due dates during December 2013, ORS and the Appellants filed their respective written direct testimony, the Applicants filed written rebuttal testimony in response to the Appellants' direct testimony, and lastly, the

Appellants filed surrebuttal written testimony in response to the Applicants' rebuttal testimony. ORS's witness, Senior Research Analyst Gene Soult, has over 30 years of experience related to all aspects of nuclear, hydro, and fossil generation. (R. p. 331, lines 19-22.) Mr. Soult testified about ORS's review of the Application, its supporting testimony, and responses to ORS discovery. (R. p. 331, line 23 – p. 332, line 16.) Mr. Soult concluded the requirements of the Siting Act were met, and this position was affirmed by ORS joining the Settlement Agreement supporting the Application. (R. p.333, lines 18-21 and R. p. 20-27.)

Appellants' witnesses, SCCCL Energy and Climate Director Hamilton Davis and SACE Director of Research John Wilson, made three recommendations to the Commission in their direct pre-filed written testimony. (R. p. 305, lines 9-21.) First, they recommended the Commission condition any certification of the Lee Unit on an in service date of 2018 rather than 2017 as proposed in the Application. *Id.* Second, they recommended that the Commission ensure exhaustion of cost-effective opportunities to defer or avoid the additional Lee Unit through lower-cost, lower-risk resources. *Id.* Third, they recommended the Commission direct Duke Energy to solicit developer interest in a 375 MW solar facility located at or near the Lee Unit site at a cost consistent with the cost to operate the Lee Unit. *Id.* The third recommendation was restated in their written testimony as, "We recommend that the Commission, as a condition of any certification of the proposed Lee NGCC Unit, require the Company to develop or procure, through an RFP [request for proposal] process initiated in 2014, an additional 375 MW of solar capacity at or near the Lee site.... [W]e further recommend that the Commission require that the best proposals that meet Duke Energy's minimum terms be

accepted up to 375 MW of solar capacity." (R. p. 322, lines 6-12.) It is the Appellants' third recommendation that is the crux of this appeal.

On January 3, 2014, ORS and the Applicants filed a Settlement Agreement wherein ORS endorsed the Application of Duke and NCEMC. (R. p. 20-27.) The Appellants declined the opportunity to join the Settlement Agreement.

On January 7, 2014, the Commission convened a formal hearing on the Application. On May 2, 2014, the Commission issued Order No. 2014-408 granting the CECPCN and approving the Settlement Agreement. On May 15, 2014, the Appellants filed a Petition for Rehearing stating the CECPCN was not granted in compliance with the Siting Act. The Commission denied the Petition for Rehearing in Order No. 2014-546 dated July 30, 2014. This appeal of the Commission's orders ensued.

STANDARD OF REVIEW

"This Court employs a deferential standard of review when reviewing a PSC decision and will affirm that decision when substantial evidence supports it." *S.C. Energy Users Comm. v. Pub. Serv. Comm'n of S.C.*, 388 S.C. 486, 490, 697 S.E.2d 587, 589-90 (2010) (citing *Duke Power Co. v. Pub. Serv. Comm'n of S.C.*, 343 S.C. 554, 558, 541 S.E.2d 250, 252 (2001); *see also* S.C. Code Ann. § 1-23-380 (Supp. 2014)). This standard of review, as established in the South Carolina Administrative Procedures Act, S.C. Code Ann. § 1-23-380, provides that this Court shall not substitute its judgment for that of the agency as to the weight of the evidence on questions of fact. S.C. Code Ann. § 1-23-380(A)(6) (Supp. 2014); *Long Cove Home Owners' Ass'n, Inc. v. Beaufort Cnty. Tax Equalization Bd.*, 327 S.C. 135, 139, 488 S.E.2d 857, 860 (1997). A reviewing court may reverse or modify a decision of an agency if the findings, inferences, conclusions or

decisions of that agency are "clearly erroneous in view of the reliable, probative and substantial evidence on the whole record," or "arbitrary or capricious or characterized by abuse of discretion or clearly unwarranted exercise of discretion." S.C. Code Ann. § 1-23-380(A)(6)(e),(f) (Supp. 2014). Under this "substantial evidence" standard of review, the factual findings of the agency are presumed correct and will be set aside only if unsupported by substantial evidence. *See Sea Pines Ass'n for the Prot. of Wildlife, Inc. v. S.C. Dep't of Natural Res. & Cmty. Servs. Assocs., Inc.*, 345 S.C. 594, 603-4, 550 S.E.2d 287, 292-3 (2001). "Substantial evidence is not a mere scintilla of evidence nor evidence viewed blindly from one side, but is evidence which, when considering the record as a whole, would allow reasonable minds to reach the conclusion that the agency reached." *Waters v. S.C. Land Res. Conservation Comm'n*, 321 S.C. 219, 226, 467 S.E.2d 913, 917 (1996) (citing *Palmetto Alliance, Inc. v. S.C. Pub. Serv. Comm'n,* 282 S.C. 430, 432, 319 S.E.2d 695, 696 (1984)). "The possibility of drawing two inconsistent conclusions from the evidence does not prevent the Commission's finding from being supported by substantial evidence." *Sharpe v. Case Produce, Inc.*, 336 S.C. 154, 160, 519 S.E.2d 102, 105 (1999). "[T]he burden is on Appellants to prove convincingly that the agency's decision is unsupported by the evidence." *Waters*, 321 S.C. at 226, 467 S.E.2d at 917.

On matters of statutory construction, "[t]his Court, although not bound by the decision, will ordinarily defer to the opinion of a state agency as to the interpretation of a statute it is charged with the duty of enforcing." *S.C. Coastal Conservation League v. S.C. Dep't of Health & Envtl. Control*, 380 S.C. 349, 362, 669 S.E.2d 899, 906 (2008). "The construction of a statute by the agency charged with its administration will be accorded the most respectful consideration and will not be overruled absent compelling

reasons." *Brown v. S.C. Dep't of Health & Envtl. Control*, 348 S.C. 507, 515, 560 S.E.2d 410, 414 (2002) (citing *Dunton v. S.C. Bd. of Examiners in Optometry*, 291 S.C. 221, 223, 353 S.E.2d 132, 133 (1987)). Thus, because the Commission's findings are presumptively correct, the party challenging the Commission's order bears the burden of convincingly proving the decision is clearly erroneous, or arbitrary or capricious, or an abuse of discretion, in view of the substantial evidence of the record as a whole. *S.C. Energy Users Comm.*, 388 S.C. at 491, 697 S.E.2d at 590 (citing *Duke Power Co. v. Pub. Serv. Comm'n of S.C.*, 343 S.C. at 558, 541 S.E.2d at 252 (2001)); *see also* S.C. Code Ann. § 1-23-380(A)(6).

ARGUMENT

I. THE COMMISSION DID NOT ERR IN ITS DECISION APPLYING THE SITING ACT AND ITS DECISION IS SUPPORTED BY SUBSTANTIAL EVIDENCE.

Appellants argue the Commission (a) misunderstood and misapplied Appellants' position; (b) did not appropriately consider the environmental impact; and (c) erroneously concluded that it could not alter the Application. (Brief p. 10-17.) (R. p.97-101.)

A. The Commission did not misunderstand or misapply Appellants' position

Appellants assert their position has been misunderstood and misapplied. (Brief p. 10-12.) (R. p. 97-101.) ORS disagrees. The position asserted in Appellants' Petition for Reconsideration before the Commission and in Appellants' Brief before this Court has been modified from the position presented during the hearing.

In pre-filed testimony, Appellants recommended the Commission direct Duke Energy to solicit developer interest in a 375 MW solar facility located at or near the Lee

Unit site at a cost consistent with the cost to operate the Lee Unit. (R. p. 305, lines 19-21.) The above recommendation was repeated in Appellant's written direct testimony as, "We recommend that the Commission, as a condition of any certification of the proposed Lee NGCC Unit, require the Company to develop or procure, through an RFP process initiated in 2014, an additional 375 MW of solar capacity at or near the Lee site.... [W]e further recommend that the Commission require that the best proposals that meet Duke Energy's minimum terms be accepted up to 375 MW of solar capacity." (R. p. 322, lines 6-12.) At the hearing, Appellants testified that the solar capacity was not anticipated to be a capacity increase, but complementary capacity which could be used to offset the costs of operating the Lee Unit. (R. p. 324, lines 10-14.)

When reviewing Appellants' testimony as a whole, ORS understood Appellants' recommendation as one causing an additional 375 MW above and beyond the 750 MW Lee Unit. The recommended solar facility and its capacity, whether complementary or not, is additional capacity. Although ORS supported the certificate for the 750 MW Lee Unit, ORS was unwilling to support additional unneeded capacity. The Commission declined Appellants 375 MW solar recommendation setting forth the following reasons:

- Applicants demonstrated a need for a specified level of capacity in conjunction with energy production (also known as generation).[1] (R. p. 15-16.)

[1] The U.S. Energy Information Administration defines "capacity" and "generation" as follows:
"Capacity" is the maximum electric output a generator can produce under specific conditions. Nameplate capacity is determined by the generator's manufacturer and indicates the maximum output a generator can produce without exceeding design thermal limits.
"Generation" is the amount of electricity a generator produces over a specific period of time. For example, a generator with 1 megawatt ("mW") capacity that operates at that capacity consistently for one hour will produce 1 megawatthour ("mWh") of electricity. If it operates at only half that capacity for one hour, it will produce 0.5 mWh of electricity. Many generators do not operate at their full capacity all the time; they may

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- A need was shown for the full 750 MWs that would be produced by the Lee Unit to meet base or intermediate load requirements at an expected capacity factor[2] between 50% to 75% for a period of 20 to 30 years.[3] *Id.*
- Solar energy has a much lower operating capacity factor due to its limited availability and reliability, making it not an optimal resource for base or intermediate load. *Id.* Any MWs generated from solar would be in addition to the Applicant-needed capacity requirements and capital investment would be needed to build a solar facility. (R. p. 16.)
- Based upon Duke Energy's Integrated Resource Plan which shows future planning for electricity needs, the additional 375 MW of solar capacity sought by the Appellants is not needed at this time. *Id.*

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vary their output according to conditions at the power plant, fuel costs, and/or as instructed from the electric power grid operator.
http://www.eia.gov/tools/faqs/faq.cfm?id=101&t=3

[2] The U.S. Energy Information Administration defines "capacity factor" as a measure of how often an electric generator runs for a specific period of time. It indicates how much electricity a generator actually produces relative to the maximum it could produce at continuous full power operation during the same period. For example, if a one megawatt generator produced 5,000 megawatthours the entire year, its capacity factor would be 0.57 or 57% (5,000 megawatthours / 8,760 megawatthours at full capacity for the entire year) of the total amount of electricity the generator could have produced if it operated at full capacity the entire year. Generators with relatively low fuel costs are usually operated to supply base load power and typically have average annual capacity factors of 0.70 or more. Conversely, generators with lower capacity factors might indicate average operation during peak demand periods and/or high fuel costs, or operation based on the availability of a variable energy source, such as hydro, solar, and wind energy.
http://www.eia.gov/tools/faqs/faq.cfm?id=187&t=3

[3] Applicant witness Hager testified:

> As CCL and SACE witnesses note, the largest solar facility in the world is under construction in Arizona and will provide 290 MWs of capacity. It is unclear why CCL and SACE believe the Anderson, South Carolina, area is a likely spot for an even larger facility. In addition, a 375 MW solar facility would be a poor substitute for the Lee CC Project. It would only provide approximately 150 MWs of summer peak equivalent capacity compared to the 750 MW Lee Project and can only provide about 10% of the energy that the Lee Project is capable of providing. . . . The 375 MW facility proposed by CCL and SACE would require approximately 2,625 acres of land. By contrast the footprint of the 750 MW Lee CC Project is estimated to be approximately 20 acres. (R. p. 207, lines 9-21.)

- It is not good practice to grant permission to build or secure more capacity than is needed as this could ultimately result in customers paying more than necessary for electric service. *Id.*
- Duke Energy could voluntarily submit an RFP to consider solar generation without the Commission requiring it to do so. (R. p. 17.)

The Commission's reasoning in Order No. 2014-408 shows that it had the same understanding of Appellants' recommendation as ORS.

After Commission Order No. 2014-408 was issued denying Appellants' recommendation, Appellants petitioned the Commission for a rehearing with the premise, among other things, that the Commission misapprehended the nature and intent of the solar recommendation, and because of the misunderstanding, the Commission's order is unsupported by substantial evidence. (R. p. 99.) In its Petition for Rehearing, the Appellants state that the 375 MW solar RFP is not to be above and beyond the 750 MW, but instead the proposal is for solar to offset plant operating costs, when cost-effective to do so. (R. p. 89.) Appellants also state in their Petition for Rehearing that their recommendation is that (1) solar be used as a fuel substitute when available in order to offset the operating costs of the gas plant which mainly come from fuel[4] and (2) Duke Energy be required to issue a RFP for solar capacity that, as delivered, would displace production at the gas plant and reduce fuel burned there. (R. p.97-98.) Appellants' Petition further clarifies their position to state that customers should be "held harmless." (R. p. 98.)

[4] Applicants' Brief, which ORS supports, states why this recommendation is inconsistent with the requirements of S.C. Code Section 58-27-865(F).

The position presented to the Commission during the hearing process does not reflect what Appellants now claim to be their position. An issue raised for the first time in a party's petition for rehearing to the Commission is not preserved for judicial review. *See Kiawah Property Owners Group v. Public Serv. Comm'n*, 359 S.C. 105, 113, 597 S.E.2d 145, 149 (2004). Here, Appellants' position that ratepayers are to be held harmless and the solar capacity is not to be in addition to the 750 MW is not plainly stated until its Petition for Rehearing.

The Appellants' failure to clearly state its position during the proceeding before the Commission is being couched in its Petition for Rehearing and Brief as a Commission misunderstanding of Appellants' position. It appears the Appellants are using the Petition for Rehearing and appellate process to re-characterize its arguments and position to get multiple bites at the apple.

When appellant's contentions are not presented or passed on by the trial judge, such contentions will not be considered on appeal. *I'On, L.L.C. v. Town of Mt. Pleasant*, 338 S.C. 406, 422, 526 S.E.2d 716, 724 (2000) (citing *Roche v. S.C. Alcoholic Beverage Control Comm'n*, 263 S.C. 451, 454, 211 S.E.2d 243, 244 (1975)). This "prevents a party from keeping an ace card up his sleeve – intentionally or by chance – in the hope that an appellate court will accept that ace card and, via a reversal, give him another opportunity to prove his case." *Id.* Had Appellants' testimony plainly stated what Appellants now contend is their position – that is for ratepayers to be held harmless and that the solar capacity is not to be in addition to the 750 MW – then Commission Order No. 2014-408 and ORS testimony would have specifically addressed the concerns now being raised.[5] It

[5] "In *Irving v. Mazda Motor Corp.*, 136 F.3d 764 (11th Cir. 1998), [the court] expressed [its] concern that 'too often our colleagues on the district courts complain that the appellate cases about which they read were

is not the Commission's role to decode parties' positions or infer relief. Appellants should not be given another bite at the apple. Lastly, even if this Court agrees with Appellants that ORS and the Commission misunderstood Appellants' position, the Commission's decision to deny the solar recommendation is nevertheless supported by substantial evidence and should not be overturned.

B. The Commission appropriately considered the environmental impact pursuant to S.C. Code Ann. § 58-33-160(1)(b) and (c)

Appellants argue the Commission did not consider the environmental impact as required by S.C. Code Ann. § 58-33-160(1)(b) and (c) (1976). S.C. Code Ann. § 58-33-160(1) (1976) states:

> (1) The Commission shall render a decision upon the record either granting or denying the application as filed, or granting it upon such terms, conditions or modifications of the construction, operation or maintenance of the major utility facility as the Commission may deem appropriate; such conditions shall be as determined by the applicable State agency having jurisdiction or authority under statutes, rules, regulations or standards promulgated thereunder, and the conditions shall become a part of the certificate. The Commission may not grant a certificate for the construction, operation and maintenance of a major utility facility, either as proposed or as modified by the Commission, unless it shall find and determine:
>
> (a) The basis of the need for the facility.
>
> (b) The nature of the probable environmental impact.
>
> (c) That the impact of the facility upon the environment is justified, considering the state of available

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not the cases argued before them. We cannot allow Plaintiff to argue a different case from the case she presented to the district court." *Access Now, Inc. v. Southwest Airlines Co.*, 385 F.3d 1324, 1331 (11th Cir. 2004).

> technology and the nature and economics of the various alternatives and other pertinent considerations.
>
> (d) That the facilities will serve the interests of system economy and reliability.
>
> (e) That there is reasonable assurance that the proposed facility will conform to applicable State and local laws and regulations issued thereunder, including any allowable variance provisions therein, except that the Commission may refuse to apply any local law or local regulation if it finds that, as applied to the proposed facility, such law or regulation is unreasonably restrictive in view of the existing technology, or of factors of cost or economics or of the needs of consumers whether located inside or outside of the directly affected government subdivisions.
>
> (f) That public convenience and necessity require the construction of the facility.

Appellants assert error in that the Commission summarized the favorable testimony of ORS and the Applicants, yet ignored conflicting testimony in the record showing that the Lee Unit would emit air pollutants and consume large amounts of water. (Brief p. 13.) ORS disagrees. As in *S.C. Energy Users Comm. v. S.C. Elec. & Gas*, 410 S.C. 348, 360, 764 S.E.2d 913, 919 (2014) the Commission parsed all of the evidence presented during the hearing and provided a detailed summary of all of the testimony on which it based its very technical findings. The Commission's Order addresses each finding required by S.C. Code Ann. § 58-33-160(1) and thoroughly discusses the environmental impact. (R. p. 12-18.) *See also* infra. p. 18 and footnote 6 of this Brief noting Applicants' Application is over five-hundred pages and includes numerous analyses related to water quality, air quality, cultural resources, aquatic life, botanical life and wildlife. Further, there is no Appellant testimony addressing water – concerns or otherwise. The Commission, however, inquired about water usage specifically in drought

conditions. (R. p. 290, lines 2-21.) Applicant witness Landseidel responded there is sufficient water flow from the Saluda River if there are drought conditions and with the retirement of two units currently using the water flow, the impact will be less than what it currently is. (R. p. 290, lines 5-14.)

The subject of pollutants was raised only in cross examination by the Appellants inquiring from Applicants' witness whether pollutants would be lower if the Lee Unit operated less. (R. p. 286, lines 1-18.) Appellants' testimony did not discuss pollutants, but discussed emissions in the context of a solar facility having lower emissions than the proposed plant. (R. p. 321, lines 24-26.) The Commission inquired about emissions. (R. p. 288, lines 11-14.) In response to Commission questioning, Landseidel testified there would be virtually no mercury emissions from the Lee Unit. (R. p. 288, lines 11-20.) Applicant witness Gillespy testified that the Lee Unit will add cost-effective, highly efficient natural gas generation to the company's system, adding to its flexibility and fuel diversity, and it will have state-of-the-art emission controls to reduce environmental impact on air and water. (R. p. 152, lines 1-5.) Gillespy further testified that because the Lee Project will be built at the existing Lee Steam Station, environmental impacts should be further reduced, as many existing resources necessary for construction are already in place. (R. p. 152, lines 5-9.)

ORS witness Soult testified as to each determination required by S.C. Code Ann. § 58-33-160(1). (R. p. 333, line 11- p.336, line 20.) With respect to the environmental impact, Soult testified, "The overall environmental impact of the changes to the Lee Steam Station, including the addition of the LCCP, is expected to be positive." (R. p. 335, lines 3-5.) With respect to the public convenience and necessity, Mr. Soult

concluded, "ORS's review of the information provided in the Joint Application indicates that the Company intends to build an efficient and reliable plant that will be economical and minimize the environmental impact, while strengthening the reliability of electric generation and the transmission grid." (R. p. 336, lines 15-20.)

The Supreme Court will not set aside an order of the Commission unless it is found by a convincing showing to be unsupported by evidence or to embody arbitrary or capricious action as a matter of law. *See S.C. Cable Television Ass'n v. Southern Bell Tel. & Tel. Co.*, 308 S.C. 216, 219, 417 S.E.2d 586, 588 (1992). The substantial evidence rule means that a court will not overturn a finding of fact by an administrative agency unless there is no reasonable probability that the facts could be as related by a witness upon whose testimony the finding was based. *See Nucor Steel v. S.C. Pub. Serv. Comm'n*, 310 S.C. 539, 545, 426 S.E.2d 319, 322 (1992). The Commission did not ignore conflicting testimony, its order is based on substantial evidence, and there is no error.

In the environmental impact discussion in Appellants' Brief, Appellants discuss a 2002 Commission Order, Order No. 2002-120 in Docket No. 2001-411-E, wherein the Commission denied an Application filed by Greenville County Power, LLC for a CECPCN for a proposed combined cycle plant in Greenville County. In contrast to the present case where only ORS, the Applicants and Appellants participated, in the 2001 proceeding there were ten intervenors including eight *pro se* intervenors. In addition, statutory party DHEC participated and filed testimony. Here, DHEC did not participate in the proceeding effectively remaining silent on the Application.

Among the Commission's consideration in denying Greenville County Power, LLC's Application was the lack of certain environmental analyses. The Concurring Opinion with Commission Order No. 2002-120 states, "The lack of sound scientific and engineering analysis by the applicant regarding the synoptic, cumulative air and water impacts could not be ignored by this Commission." Order No. 2002-120, pg. 18. In the present case, Applicants' Application is over five-hundred pages and includes numerous analyses related to water quality, air quality, cultural resources, aquatic life, botanical life and wildlife. *See* Application Sections 2, 4, 6, Appendix A and D for analyses and Hearing Exhibit 4 for Applicants' Siting Study.[6] ORS witness Soult testified that the Application and supporting testimony contained the information required by the Siting Act for a CECPCN. (R. p. 333, lines 18-21.) Thus, the record contains substantial evidence to support the Commission's Orders.

C. The Commission did not err in declining to apply the Siting Act's modification clause

Appellants argue the Commission erred in declining to apply the Siting Act's modification clause. Appellants argue the Commission has latitude to make changes to an Application and point to S.C. Code Ann. § 58-33-160(1) which states in part:

> The Commission shall render a decision upon the record either granting or denying the application as filed, or granting it upon such *terms, conditions or modifications of the construction, operation or maintenance of the major utility facility as the Commission may deem appropriate*; such conditions shall be as determined by the applicable State agency having jurisdiction or authority under statutes,

[6] ORS's Designation of Matter requested that these portions of the Application be included. However, upon receiving the Record on Appeal and noting their absence, ORS considered the matter and chose not to pursue having the portions included.

> rules, regulations or standards promulgated thereunder, and the conditions shall become a part of the certificate. (Emphasis added.)

Among the reasons for denying the Appellants' recommendation for solar, the Commission stated in Order No. 2014-408:

> [A] solar generating facility cannot replace the needed MWs from the LCCP. We do not think it is good practice for this Commission to grant permission for the Company to build or secure more capacity than is needed as this could ultimately result in customers paying more than necessary for electric service. It is also questionable whether this would be permitted under the Siting Act given that such a grant of permission would be enlarging the scope of the Application without notice to the public. Lastly, it is also questionable whether this Commission can change the type of facility being requested by the Company. Here, SACE and SCCCL request that an RFP be required for the consideration of solar to be added to the LCCP. The Commission views this as requiring the Company to materially change its Application. (R. p. 16-17.)

The American Heritage College Dictionary defines "modification" as a small alteration, adjustment, or limitation. American Heritage College Dictionary p. 894 (4th ed. 2002). ORS disagrees that the statute offers the leeway endorsed by Appellants.

"The construction of a statute by the agency charged with its administration will be accorded the most respectful consideration and will not be overruled absent compelling reasons." *Brown v. S.C. Dep't of Health & Envtl. Control*, 348 S.C. 507, 515, 560 S.E.2d 410, 414 (2002) (citing *Dunton v. S.C. Bd. of Examiners in Optometry*, 291 S.C. 221, 223, 353 S.E.2d 132, 133 (1987)). "A statute as a whole must receive practical, reasonable, and fair interpretation consonant with the purpose, design, and policy of lawmakers." *Sloan v. S.C. Bd. of Physical Therapy Exam'rs*, 370 S.C. 452, 468, 636

S.E.2d 598, 606 (2006). The court should not consider the particular clause being construed in isolation, but should read it in conjunction with the purpose of the whole statute and the policy of the law. *S.C. Coastal Council v. South Carolina State Ethics Comm'n*, 306 S.C. 41, 44, 410 S.E.2d 245, 247 (1991). "Where the statute's language is plain and unambiguous, and conveys a clear and definite meaning, the rules of statutory interpretation are not needed and the court has no right to impose another meaning." *Hodges v. Rainey*, 341 S.C. 79, 85, 533 S.E.2d 578, 581 (2000). Among the reasons the Commission concluded it would not be appropriate to accept Appellants' solar recommendation is that such an expansion of the Application is questionable under the limits of the Siting Act, given that the recommendation enlarges the scope of the Application without public notice. (R. p. 16-17.) *See also* S.C. Code Ann. §§ 1-23-320 (Supp. 2014) and 58-33-120 (Supp. 2014) (requiring notice). As the entity statutorily charged with representing the public interest before the Commission, ORS appreciates the Commission's concern for public notice. S.C. Code Ann. § 58-4-10(B) (Supp. 2014). The Commission's decision, which is supported by ORS, should receive deference.

CONCLUSION

The Commission did not misunderstand or misapply Appellants' position, appropriately considered the environmental impact, and did not err in declining to apply the Siting Act's modification clause. In addition, ORS has reviewed Applicants' Brief and supports it in its entirety. Commission Order Nos. 2014-408 and 2014-546 should be affirmed in their entirety.

Respectfully submitted,

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THE STATE OF SOUTH CAROLINA
In The Court of Appeals

APPEAL FROM
THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

Docket No. 2013-392-E
Appellate Case No. 2014-001514

In The Matter of Joint Application of Duke Energy Carolinas, LLC and North Carolina Electric Membership Corporation for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of a 750 MW Combined Generating Plant Near Anderson, SC

CERTIFICATE OF COUNSEL

The undersigned hereby certifies that this Final Brief of Respondent Office of Regulatory Staff complies with Rule 211(b), SCACR.

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CERTIFICATE OF SERVICE

This is to certify that I have caused to be served this day one (1) copy of **the Office of Regulatory Staff's Final Brief** by placing same in the care and custody of the United States Postal Service with first class postage affixed thereto and addressed as follows:

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THIS OPINION HAS NO PRECEDENTIAL VALUE. IT SHOULD NOT BE CITED OR RELIED ON AS PRECEDENT IN ANY PROCEEDING EXCEPT AS PROVIDED BY RULE 268(d)(2), SCACR.

THE STATE OF SOUTH CAROLINA
In The Court of Appeals

In the Matter of Joint Application of Duke Energy Carolinas, LLC and North Carolina Electric Membership Corporation for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of a 750MW Combined Generating Plant Near Anderson, SC.

Appellate Case No. 2014-001514

Appeal from the Public Service Commission

Unpublished Opinion No. 2016-UP-054
Heard January 14, 2016 – Filed February 10, 2016

AFFIRMED

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Len Sullivan Anthony, of North Myrtle Beach, for Respondent North Carolina Electric Membership Corporation.

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Richard Lee Whitt, Austin & Rogers, PA, of Columbia, for Respondent Invenergy Therman Development, LLC.

PER CURIAM: The South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy (the Alliance) appeal the Public Service Commission's decision to issue Duke Energy Carolinas, LLC and the North Carolina Electric Membership Corporation (NCEMC) a Certificate of Environmental Compatibility and Public Convenience and Necessity to build a 750 megawatt combined cycle natural gas-fired generating facility near Anderson. The Coastal Conservation League and the Alliance argue the Commission erred in issuing the Certificate by (1) finding the proposed plant's environmental impact was justified and (2) not requiring Duke Energy and NCEMC to modify their application for the Certificate. We affirm and find (1) the Commission considered and understood the Coastal Conservation League and the Alliance's proposed solar component, (2) substantial evidence supports the Commission's issuance of the Certificate, and (3) there is no legal basis for requiring the Commission to condition the Certificate on Duke Energy soliciting bids for the proposed solar plant.

"No person shall commence to construct a major utility facility without first having obtained a certificate[1] issued with respect to such facility by the Commission." S.C. Code Ann. § 58-33-110(1) (2015). "An applicant for a certificate shall file an

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[1] "The term 'certificate' means a certificate of environmental compatibility and public convenience and necessity." S.C. Code Ann. § 58-33-20(8) (2015).

application with the commission, in such form as the commission may prescribe." S.C. Code Ann. § 58-33-120(1) (2015).

> The Commission shall render a decision upon the record either granting or denying the application as filed, or granting it upon such terms, conditions or modifications of the construction, operation or maintenance of the major utility facility as the Commission may deem appropriate; such conditions shall be as determined by the applicable State agency having jurisdiction or authority under statutes, rules, regulations or standards promulgated thereunder, and the conditions shall become a part of the certificate. The Commission may not grant a certificate for the construction, operation, and maintenance of a major utility facility, either as proposed or as modified by the Commission, unless it shall find and determine:
>
> (a) The basis of the need for the facility.
>
> (b) The nature of the probable environmental impact.
>
> (c) That the impact of the facility upon the environment is justified, considering the state of available technology and the nature and economics of various alternatives and other pertinent considerations.
>
> (d) That the facilities will serve the interests of the system economy and reliability.
>
> (e) That there is reasonable assurance that the proposed facility will conform to applicable State and local laws and regulations issued thereunder, including any allowable variance provisions therein, except that the Commission may refuse to apply any local law or local regulation if it finds that, as applied to the proposed facility, such law or regulation is unreasonably restrictive in view of the existing technology, or of factors of cost or

economics or of the needs of consumers whether located inside or outside of the directly affected government subdivisions.

(f) That public convenience and necessity require the construction of the facility.

S.C. Code Ann. § 58-33-160(1) (2015). "[T]his Court employs a deferential standard of review when reviewing a decision of the Public Service Commission and will affirm that decision when substantial evidence supports it." *Friends of Earth v. Pub. Serv. Comm'n*, 387 S.C. 360, 366, 692 S.E.2d 910, 913 (2010).

First, we find the Commission considered and understood the Coastal Conservation League and the Alliance's solar proposal. The Commission made the findings required by South Carolina Code section 58-33-160. Specifically at issue in this appeal, the Commission made findings on "the nature of the probable environmental impact" of the proposed gas plant and determined the impact was "justified, considering the state of available technology and the nature and economics of various alternatives and other pertinent considerations." *See* § 58-33-160(1)(b)-(c).

The Commission found Duke Energy and NCEMC had appropriately evaluated the environmental impacts of the proposed plant, and the Commission described those impacts. Specifically, the Commission found the proposed plant (1) had "critical infrastructure such as available land, water supply, and transmission facilities . . . already in place," due to its location—adjacent to an existing power plant; (2) had archeological clearance; (3) would have "minimal effects on the visual resources and scenic quality" of the area; (4) would feature "state of the art environmental control technology for natural gas combined cycle generation;" and (5) would include a cooling tower to minimize "both the intake and discharge impacts to the Saluda River." The Commission also noted the Office of Regulatory Staff's witness testified the proposed plant would not result in any significant impacts to the environment and the Department of Health and Environmental Control, the Department of Natural Resources, and the Department of Parks, Recreation and Tourism were all parties to the case and did not appear.

Additionally, the Commission found the impact of the proposed plant was "justified, considering the state of available technology and the nature and economics of the various alternatives and other pertinent considerations." *See* § 58-33-160(1)(c). The Commission considered the solar proposal and found there

was no need for an additional 375 megawatt solar facility.[2] The Commission found Duke Energy had "conducted a thorough review in determining" the proposed plant "is best to meet its future electricity generating needs," and "decline[d] to require [Duke Energy] to do further."[3]

Second, we find substantial evidence supports the Commission's issuance of the Certificate. "[T]he [c]ourt may not substitute its judgment for the Commission's on questions about which there is room for a difference of intelligent opinion." *Friends of Earth*, 387 S.C. at 366, 692 S.E.2d at 913. "[T]he Commission's findings are presumptively correct, [and] the party challenging a Commission order bears the burden of convincingly proving the decision is clearly erroneous, or arbitrary or capricious, or an abuse of discretion, in view of the substantial evidence on the whole record." *Id.*

The Commission made specific findings based on testimony regarding the nature of the environmental impact of the proposed plant and whether it was justified. The Commission accurately described the solar proposal both in its order issuing the Certificate and its order denying the petition for rehearing. Additionally, Duke Energy's application and its witnesses[4] described the proposed plant's projected impact on water quality, air quality, and cultural resources. For these reasons, the Commission's finding that the proposed plant was justified, without the solar plant, was supported by the evidence.

Third, we find there is no legal basis for requiring the Commission to condition the Certificate on Duke Energy soliciting bids for the proposed solar plant. Section

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[2] The Coastal Conservation League and the Alliance argue the Commission misunderstood their solar proposal. However, the Coastal Conservation League and the Alliance made this same argument in a petition for rehearing on the Commission's order issuing the Certificate. The Commission denied the petition for rehearing and emphasized it understood the proposed solar plant was to be used to "offset gas generation when conditions exist for economic solar energy production."

[3] The Commission also encouraged Duke Energy to voluntarily consider solar generation.

[4] Interestingly, one of Duke Energy's witnesses testified the proposed solar plant would be the largest solar plant in the world and would require approximately 2,625 acres of land.

58-33-160 allows the Commission to grant an application for a certificate "upon such terms, conditions or modifications of the construction, operation or maintenance of the major utility facility as the Commission may deem appropriate." § 53-33-160(1). However, this section does not enable the Commission to grant an application but require more than a "modification" to the application. "Modification" is defined as a "small alteration, adjustment, or limitation." *Modification*, Webster's II New College Dictionary (Houghton Mifflin Co. ed., 1999). We hold requiring Duke Energy to build—or solicit bids for—the proposed solar plant would constitute more than a "modification" to its application. *See* 64 Am. Jur. 2d *Public Utilities* § 143 (2011) ("Public service commissions are administrative agencies whose power is derived from the legislature and whose functions are legislative functions."); *Sloan v. S.C. Bd. of Physical Therapy Exam'rs*, 370 S.C. 452, 468, 636 S.E.2d 598, 606 (2006) ("A statute as a whole must receive practical, reasonable, and fair interpretation consonant with the purpose, design, and policy of lawmakers.").

We hold the Commission considered and understood the Coastal Conservation League and the Alliance's solar proposal, substantial evidence supports the Commission's issuance of the Certificate, and there is no legal basis for requiring the Commission to condition the Certificate on Duke Energy soliciting bids for the proposed solar plant. Accordingly, the Commission's issuance of a Certificate to Duke Energy and NCEMC is **AFFIRMED.**

FEW, C.J., and KONDUROS and LOCKEMY, JJ., concur.

2016 WL 526516
Only the Westlaw citation is currently available.

UNPUBLISHED OPINION. CHECK COURT RULES BEFORE CITING.

Court of Appeals of South Carolina.

In the Matter of Joint Application of DUKE ENERGY CAROLINAS, LLC and North Carolina Electric Membership Corporation for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of a 750MW Combined Generating Plant Near Anderson, SC.

Appellate Case No. 2014–001514.
|
No. 2016–UP–054.
|
Heard Jan. 14, 2016.
|
Filed Feb. 10, 2016.

Appeal from the Public Service Commission.

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Opinion

PER CURIAM.

*1 The South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy (the Alliance) appeal the Public Service Commission's decision to issue Duke Energy Carolinas, LLC and the North Carolina Electric Membership Corporation (NCEMC) a Certificate of Environmental Compatibility and Public Convenience and Necessity to build a 750 megawatt combined cycle natural gas-fired generating facility near Anderson. The Coastal Conservation League and the Alliance argue the Commission erred in issuing the Certificate by (1) finding the proposed plant's environmental impact was justified and (2) not requiring Duke Energy and NCEMC to modify their application for the Certificate. We affirm and find (1) the Commission considered and understood the Coastal Conservation League and the Alliance's proposed solar component, (2) substantial evidence supports the Commission's issuance of the Certificate, and (3) there is no legal basis for requiring the Commission to condition the Certificate on Duke Energy soliciting bids for the proposed solar plant.

"No person shall commence to construct a major utility facility without first having obtained a certificate [1] issued with respect to such facility by the Commission." S.C.Code Ann. § 58–33–110(1) (2015). "An applicant for a certificate shall file an application with the commission, in such form as the commission may prescribe." S.C.Code Ann. § 58–33–120(1) (2015).

> The Commission shall render a decision upon the record either granting or denying the application as filed, or granting it upon such terms, conditions or modifications of the construction, operation or maintenance of the major utility facility as the Commission may deem appropriate; such conditions shall be as determined by the applicable State agency having jurisdiction or authority under statutes, rules, regulations or standards promulgated thereunder, and the conditions shall become a part of the certificate.

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> The Commission may not grant a certificate for the construction, operation, and maintenance of a major utility facility, either as proposed or as modified by the Commission, unless it shall find and determine:
>
> (a) The basis of the need for the facility.
>
> (b) The nature of the probable environmental impact.
>
> (c) That the impact of the facility upon the environment is justified, considering the state of available technology and the nature and economics of various alternatives and other pertinent considerations.
>
> (d) That the facilities will serve the interests of the system economy and reliability.
>
> (e) That there is reasonable assurance that the proposed facility will conform to applicable State and local laws and regulations issued thereunder, including any allowable variance provisions therein, except that the Commission may refuse to apply any local law or local regulation if it finds that, as applied to the proposed facility, such law or regulation is unreasonably restrictive in view of the existing technology, or of factors of cost or economics or of the needs of consumers whether located inside or outside of the directly affected government subdivisions.
>
> ***2** (f) That public convenience and necessity require the construction of the facility.

S.C.Code Ann. § 58–33–160(1) (2015). "[T]his Court employs a deferential standard of review when reviewing a decision of the Public Service Commission and will affirm that decision when substantial evidence supports it." *Friends of Earth v. Pub. Serv. Comm'n,* 387 S.C. 360, 366, 692 S.E.2d 910, 913 (2010).

First, we find the Commission considered and understood the Coastal Conservation League and the Alliance's solar proposal. The Commission made the findings required by South Carolina Code section 58–33–160. Specifically at issue in this appeal, the Commission made findings on "the nature of the probable environmental impact" of the proposed gas plant and determined the impact was "justified, considering the state of available technology and the nature and economics of various alternatives and other pertinent considerations ." *See* § 58–33–160(1)(b)–(c).

The Commission found Duke Energy and NCEMC had appropriately evaluated the environmental impacts of the proposed plant, and the Commission described those impacts. Specifically, the Commission found the proposed plant (1) had "critical infrastructure such as available land, water supply, and transmission facilities ... already in place," due to its location—adjacent to an existing power plant; (2) had archeological clearance; (3) would have "minimal effects on the visual resources and scenic quality" of the area; (4) would feature "state of the art environmental control technology for natural gas combined cycle generation;" and (5) would include a cooling tower to minimize "both the intake and discharge impacts to the Saluda River." The Commission also noted the Office of Regulatory Staff's witness testified the proposed plant would not result in any significant impacts to the environment and the Department of Health and Environmental Control, the Department of Natural Resources, and the Department of Parks, Recreation and Tourism were all parties to the case and did not appear.

Additionally, the Commission found the impact of the proposed plant was "justified, considering the state of available technology and the nature and economics of the various alternatives and other pertinent considerations." *See* § 58–33–160(1)(c). The Commission considered the solar proposal and found there was no need for an additional 375 megawatt solar facility.[2] The Commission found Duke Energy had "conducted a thorough review in determining" the proposed plant "is best to meet its future electricity generating needs," and "decline[d] to require [Duke Energy] to do further."[3]

Second, we find substantial evidence supports the Commission's issuance of the Certificate. "[T]he [c]ourt may not substitute its judgment for the Commission's on questions about which there is room for a difference of intelligent opinion." *Friends of Earth,* 387 S.C. at 366, 692 S.E.2d at 913. "[T]he Commission's findings are presumptively correct, [and] the party challenging a Commission order bears the burden of convincingly proving the decision is clearly erroneous, or arbitrary or capricious, or an abuse of discretion, in view of the substantial evidence on the whole record." *Id.*

***3** The Commission made specific findings based on testimony regarding the nature of the environmental impact of the proposed plant and whether it was justified. The Commission accurately described the solar proposal both in its order issuing the Certificate and its order denying the petition for rehearing. Additionally, Duke Energy's application and its witnesses[4] described the proposed plant's projected impact on water quality, air quality, and cultural

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resources. For these reasons, the Commission's finding that the proposed plant was justified, without the solar plant, was supported by the evidence.

Third, we find there is no legal basis for requiring the Commission to condition the Certificate on Duke Energy soliciting bids for the proposed solar plant. Section 58–33–160 allows the Commission to grant an application for a certificate "upon such terms, conditions or modifications of the construction, operation or maintenance of the major utility facility as the Commission may deem appropriate." § 53–33–160(1). However, this section does not enable the Commission to grant an application but require more than a "modification" to the application. "Modification" is defined as a "small alteration, adjustment, or limitation." *Modification,* Webster's II New College Dictionary (Houghton Mifflin Co. ed., 1999). We hold requiring Duke Energy to build—or solicit bids for—the proposed solar plant would constitute more than a "modification" to its application. *See* 64 Am.Jur.2d *Public Utilities* § 143 (2011) ("Public service commissions are administrative agencies whose power is derived from the legislature and whose functions are legislative functions."); *Sloan v. S.C. Bd. of Physical Therapy Exam'rs,* 370 S.C. 452, 468, 636 S.E.2d 598, 606 (2006) ("A statute as a whole must receive practical, reasonable, and fair interpretation consonant with the purpose, design, and policy of lawmakers.").

We hold the Commission considered and understood the Coastal Conservation League and the Alliance's solar proposal, substantial evidence supports the Commission's issuance of the Certificate, and there is no legal basis for requiring the Commission to condition the Certificate on Duke Energy soliciting bids for the proposed solar plant. Accordingly, the Commission's issuance of a Certificate to Duke Energy and NCEMC is **AFFIRMED.**

FEW, C.J., and KONDUROS and LOCKEMY, JJ., concur.

All Citations

Not Reported in S.E.2d, 2016 WL 526516

Footnotes

1 "The term 'certificate' means a certificate of environmental compatibility and public convenience and necessity." S.C.Code Ann. § 58–33–20(8) (2015).

2 The Coastal Conservation League and the Alliance argue the Commission misunderstood their solar proposal. However, the Coastal Conservation League and the Alliance made this same argument in a petition for rehearing on the Commission's order issuing the Certificate. The Commission denied the petition for rehearing and emphasized it understood the proposed solar plant was to be used to "offset gas generation when conditions exist for economic solar energy production."

3 The Commission also encouraged Duke Energy to voluntarily consider solar generation.

4 Interestingly, one of Duke Energy's witnesses testified the proposed solar plant would be the largest solar plant in the world and would require approximately 2,625 acres of land.

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THE STATE OF SOUTH CAROLINA
In the Court of Appeals

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SC Court of Appeals

Appellate Case No. 2014-001514

APPEAL FROM THE PUBLIC SERVICE COMMISSION

Docket No. 2013-392-E

In The Matter of Joint Application of Duke Energy Carolinas, LLC and North Carolina Electric Membership Corporation for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of a 750MW Combined Generating Plant Near Anderson, SC

APPELLANTS' PETITION FOR REHEARING

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Pursuant to Rule 221(a), SCACR, the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy (collectively, "Appellants") respectfully petition for rehearing and reconsideration of this Court's February 10, 2016 Per Curiam Opinion affirming the decision of the Public Service Commission of South Carolina ("PSC" or "Commission") to issue a Certificate of Environmental Compatibility and Public Convenience and Necessity ("Certificate") granted to Respondents Duke Energy Carolinas, LLC ("Duke") and the North Carolina Electric Membership Corporation ("NCEMC") for the proposed Lee natural gas combined cycle ("NGCC") power plant in Anderson County, South Carolina.

INTRODUCTION

Under the Utility Facility Siting and Environmental Protection Act, (the "Act"), the Commission "may not" grant a certificate for the construction or operation of a major utility facility "unless" it finds and determines that "the impact of the facility upon the environment is justified, considering the state of available technology and the nature and economics of the various alternatives and other pertinent considerations." S.C. Code Ann. § 58-33-160(1)(c). The Commission can grant or deny the application "as filed," or grant it upon "such terms, conditions or modifications" of "construction, operation or maintenance" as it may deem appropriate. *Id.* § 58-33-160(1).

In this case, the Commission failed to execute its statutory charge. It was presented with a proposal for solar technology that would complement, not replace, the proposed gas plant – available technology that would save ratepayers money and lessen environmental impacts. In particular, the solar component proposed by Appellants would enable the "ramping down" of the gas plant's operations to lower its consumption of

water from the Saluda River and its emission of air pollution. The proposal would also save money, since 80-90% of a natural gas plant's costs come from burning fuel. R. p. 316.

While it was undisputed that the ramping down of gas plant operations would reduce water consumption from the Saluda River and reduce air pollution emissions, the Commission nonetheless failed to address Appellants' solar proposal. Instead, it addressed and analyzed proposals that Appellants did *not* make. By way of analogy, if Duke's proposal was to build and operate what is in essence a 10-person capacity van, Appellants' proposal was to include a hybrid electric feature for that van whose costs would be recouped with the van's gas savings.

Rather than address Appellants' proposal, the Commission refused it on grounds that did not apply to the actual proposal before the Commission. On the one hand, it claimed that Appellants had proposed too much capacity – in essence, a 40-person bus. On the other hand, it claimed, inconsistently, that Appellants had proposed too little capacity – a two-person car. Because it used reasoning that was not applicable to the proposal before it, the Commission never gave Appellants' proposal any consideration at all. In failing to do so, it arbitrarily and capriciously failed its clear statutory duty to consider all "alternatives" and "available technology" to reduce a major energy facility's environmental impacts. S.C. Code Ann. § 58-33-160(1)(c).

This Court's decision affirming the Commission contains two central errors that warrant reconsideration.

1. **The Commission Arbitrarily and Capriciously Failed to Actually Consider Appellants' Solar Proposal.**

This Court's Opinion posits that the Commission's recitation of Appellants' proposal meant that it "considered" it. *In re Duke Energy Carolinas, LLC*, No. 2014-1514, 2016 WL 526516, at *2 (Ct. App. Feb. 10, 2016). The only evidence beyond a one-line recitation of Appellants' solar proposal, however, is the Opinion's agreement with the Commission that Appellants proposed "additional" generating capacity (expressed in megawatts, or MW) beyond what is needed.

Rather than demonstrate that the Commission considered Appellants' proposal, this reasoning repeats the Commission's erroneous conflation of energy generating *capacity*, expressed in megawatts (MWs), and energy *generation*, expressed in megawatt-hours (MWhs). The record shows that Appellants never proposed "additional" MW capacity for its own sake. Instead, they proposed that Duke issue a request for proposals ("RFP") for either a solar facility or a contract to purchase solar power. Although expressed in terms of MWs, the point of the RFP was to evaluate bids from energy market participants who could deliver solar energy generation (MWhs) that would offset generation from the gas plant and allow it to ramp down operations and thereby burn less fuel. As with a hybrid vehicle, the point of the electric component (analogous to the proposed solar component in this case) is not to boost maximum horsepower, but to reduce operations of the paired fossil fuel engine, thus reducing gas use and saving money.

The Opinion correctly recognizes that this concept was put forth clearly before the Commission. *Id.* at *2, n. 2. Indeed, when asked by a Commissioner whether the proposal was to tell Duke to "pursue generation capacity beyond its needs," R. p. 324, Appellants' witness explained that it was "not a capacity need" being addressed, and not

"anticipated to be a capacity increase," but instead was a "companion piece to this plant" that "offset ... costs associated with running Lee" by "ramping down" a "percentage of the operations at the plant [and] replacing that with the solar," R. pp. 324, 325.[1]

In the end, there is simply no evidence in the record that the Commission actually considered Appellants' proposal. Instead, it fundamentally misapprehended Appellants' proposal, and rejected it on mutually inconsistent grounds that do not apply to the proposal that was actually before the Commission.[2] While it is true that the Commission, and this Court, have in places accurately recited the proposal, such recitation cannot make up for the actual failure to consider or otherwise engage its actual merits. "Consideration" of Appellants' proposal requires more than rote recitation or repetition of it. *See U.S. v. Cooper*, 437 F.3d 324, 329 (3d Cir. 2006) ("[m]eaningful consideration requires more than mere recitation that the factors have been considered"); *In re Criscione*, 173 Cal. App. 4th 60, 74-75, 92 Cal. Rptr. 3d 258, 268 (2009) (due

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[1] *See* R. p. 320 (proposal would "reduce the operating costs" of gas unit); R. p. 316 (solar as "alternative to operating the unit"); R. p. 320 (would "offset the operating costs" of gas plant); R. p. 320 (would "have operational characteristics to complement" gas plant and reduce costs of "owning and operating the unit"); R. p. 317 (goal to deliver energy "cost-effective relative to the long-term operating cost" of Lee unit).

[2] The Commission inconsistently attacked Appellants' proposal as providing too little capacity and too much, demonstrating a fundamental misunderstanding of Appellants' proposal. *Contrast* R. pp. 15-16 (Commission objecting to building gas plant with *less than* 650 megawatts [Appellants never proposed this]); R. p. 16 (objecting that "*capacity" of solar facility was below required need* [Appellants never proposed building only solar]) *with* R. p. 16 ("MWs generated from solar would be *in addition to* the 650 MW capacity requirements" [Appellants justified proposal with offsetting MWhs, not new MW capacity]); R. p. 16 ("The *additional* 375 MW of solar *capacity*...are *not needed* at this time" [same]; R. p. 16 (objecting to having "*more capacity than is needed*" [same]). Appellants proposed a solar component of a sufficiently large magnitude (expressed in MW) so that its energy generation (expressed in MWhs) would enable the gas plant to ramp down significantly and often – thus saving money and reducing impacts. That proposal was never considered by the Commission.

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consideration requires more than "rote recitation" of the relevant factors with no analysis).

The complete failure to engage on evidence that it must statutorily consider renders the Commission's decision arbitrary and capricious, and justifies remand. *S. Bell Tel. & Tel. Co. v. Pub. Serv. Comm'n,* 270 S.C. 590, 602-604, 244 S.E.2d 278, 284-285 (1978), *holding modified by Parker v. S.C. Pub. Serv. Comm'n*, 280 S.C. 310, 313 S.E.2d 290 (1984).

The failure is made all the more egregious by the uncontested truth that Appellants' proposal could reduce impacts to the environment and impacts to ratepayers. With regard to environmental impacts, for example, while the NGCC would emit nitrogen oxides ("NOx"), carbon monoxide, and volatile organic compounds, R. pp. 276, 277, operating the plant at lower power as enabled by a solar component would reduce emission of air pollution, including NOx, R. p. 286. While the plant would consume 10 cubic feet per second of water from the Saluda River, R. p. 278, or 4,488 gallons per minute, it is undisputed that operating the unit at lower output would reduce water use from the River, R. p. 285. And while the plant would emit significant amounts of carbon dioxide ("CO2") pollution, R. p. 321, it is undisputed that Appellants' proposal would yield "direct emissions reduction benefits" of carbon dioxide, R. p. 321.

From the standpoint of economics, the gas plant is estimated to cost ratepayers around $673 million to build. R. pp. 286-287. But it will be far more expensive to run. Given that operating costs, mainly the natural gas burned as fuel, will constitute 80-90% of the Lee NGCC's long-term cost, R. p. 316, the total lifetime operating costs (mainly fuel) could approach nearly $3 billion. The solar proposal put forth by Appellants

offered substantial cost savings as well as risk hedging advantages.[3] Critically, under the solar RFP proposed by Appellants, Duke would *only* have to accept a bid for solar power if the bidder could meet or beat the price that it would cost to produce that power by running the gas plant. R. p. 299. Any cost savings would be passed on to customers, while there would be zero risk of increased costs. Again, the Commission did not engage on this crucial feature of Appellants' proposal.

Had the Commission engaged on Appellants' proposal, this record evidence – showing the proposal would lessen environmental impacts and lower ratepayer risk – would have been considered. Based on the Commission's written orders, it was not. Likewise, the Commission did not address record evidence showing that, operationally, the NGCC proposed by Duke is well-suited to pair with a solar complement.[4] The record shows no consideration of any of this because the Commission did not, in fact, consider Appellants' solar proposal, or how this "available technology" would lessen the proposed gas plant's environmental impact. That failure rendered its decision arbitrary and capricious and unlawful. *Morall v. Drug Enforcement Agency*, 412 F.3d 165, 178 (D.C. Cir. 2005) (agency acts arbitrarily and capriciously when it ignores relevant testimony); *Surgicore v. Office of Pers. Mgmt.*, No. 03-C-2451, 2006 WL 733548, at *9 (N.D. Ill. Mar. 21, 2006) (agency acted "arbitrarily and capriciously" by ignoring information relevant to appeal); *Tolman v. Salt Lake Cty. Attorney*, 818 P.2d 23, 32 (Utah Ct. App.

[3] *See* R. pp. 321, 317 (incremental capital costs of solar "more than compensated by the savings in operating costs" of NGCC); R. pp. 300, 316, 320 ("offset the operating costs" of Lee); R. pp. 305, 322 (hedge against higher gas prices), R. p. 301(insulate ratepayers from the risk of increasing and volatile gas prices).

[4] The NGCC design proposed by Duke can ramp up and down quickly; does not lose efficiency when running at less than full power; and can operate on a system that includes intermittent power sources like solar. R. 285.

1991) (failure to actually consider and address contentions was agency abuse of discretion); *Buxton v. Indus. Comm'n of Utah*, 587 P.2d 121, 123 (Utah 1978) (holding "Commission is not vested with arbitrary powers; and it cannot simply ignore competent and credible evidence when there is nothing discrediting therein and there is no evidence to the contrary"); *City of Pittsburgh v. Pennsylvania Pub. Util. Comm'n,* 370 Pa. 305, 315-16, 88 A.2d 59, 64-65 (Pa. 1952) (ignoring undisputed competent evidence was "was not an exercise of judgment by the Commission but an arbitrary and unreasonable finding").

The Opinion's finding that the Commission gave any consideration to Appellants' proposal beyond reciting it should be reconsidered, and the matter remanded to the Commission for consideration of Appellants' proposal.

2. **The Statute Empowers the Commission to Condition and Modify Certifications to Save Ratepayers Money and Reduce Environmental Damage.**

As something of an alternate ground, the Opinion holds that the Commission had no choice but to reject Appellants' proposal given a highly circumscribed ability to condition its certifications on "modifications." *See In re Duke Energy*, 2016 WL 526516, at *3. Citing a dictionary entry, the Opinion holds that the Commission is empowered to consider only a "small alteration, adjustment, or limitation" to a proposed major generating facility. *See id.* This deserves reconsideration for several reasons.

First, as the Supreme Court made clear in an earlier case involving this Commission, when a statutory term such as "modification" is undefined, a court may not "merely consider the language of the particular clause being construed," but must

examine "the undefined word and its meaning in conjunction with the purpose of the whole statute and the policy of the law." *S.C. Energy Users Comm. v. S.C. Pub. Serv. Comm'n*, 388 S.C. 486, 492-493, 697 S.E.2d 587, 590-591 (2010). That was not done here. Instead, the Opinion cites a limited dictionary sub-definition of "modification," rather than the first definition set forth in the same dictionary, which is "the act of modifying," with the term "modify" defined to mean "to change in form or character: ALTER." Webster's II New College Dictionary (Houghton Mifflin Co. ed., 2001). This basic meaning of modification – to change or alter – is found in other dictionaries as well[5] and better fits "the purpose of the whole statute and the policy of the law," which the Opinion did not address.

That law requires that the Commission may *not* issue a Certificate "unless" the Commission "find[s] and determine[s]" that "the impact of the facility upon the environment is justified, considering the state of available technology and the nature and economics of the various alternatives and other pertinent considerations." S.C. Code Ann. § 58-33-160(1)(c). As noted, in carrying out this duty, the Commission can grant or deny the application "as filed," or grant it upon "such terms, conditions or modifications" of "construction, operation or maintenance" as the Commission "may deem appropriate." *Id.* § 58-33-160(1). Further, the Siting Act explicitly requires additional public notice where the Commission conditions its certification upon the modification of the location

[5] *See, e.g.*, THE AMERICAN HERITAGE DICTIONARY OF THE ENGLISH LANGUAGE (Fifth ed. 2015) (defining "modify" as "To change in form or character; alter.") (*available at* https://ahdictionary.com/word/search.html?q=modify); MERRIAM-WEBSTER (defining "modification" as "the act or process of changing parts of something : the act or process of modifying something") (available at http://www.merriam-webster.com/dictionary/modification).

of all or part of a proposed facility, *id.* § 58-33-160(2), and empowers the Commission to require after-the-fact modifications for emergency-approved facilities "if, after giving due consideration to the major utility facility, available technology and the economics involved, it finds such modification necessary in order to minimize the environmental impact," *id.* § 58-33-110(6).

Taken together, these provisions embody a clear policy choice by the General Assembly to charge and empower the Commission with actively reviewing proposals for major energy production facilities in South Carolina; to approve them only if their environmental impacts are "justified" given available alternatives; and to impose terms, conditions, and modifications for such proposals to minimize environmental impacts. It was error to construe the term "modification" without considering the statutory context or the General Assembly's intent in enacting it, and to adopt a constrained definition that undercuts the statutory scheme.

That scheme explicitly empowers the Commission to either (1) grant or deny the application "as filed," or (2) grant it upon "such terms, conditions or modifications" of "construction, operation or maintenance" as the Commission "may deem appropriate" after a full public hearing. *Id.* §§ 58-33-160(1); 58-33-130(1). The General Assembly gave the Commission something well beyond a thumbs-up or thumbs-down power: it gave it the power to condition certifications on modifications that would reduce environmental impacts and save ratepayers money. The Commission's power to condition the grant of a Certificate on a modification of the utility's proposed facility is entirely consistent with the General Assembly's broad grant of authority to the Commission:

> The commission is vested with power and jurisdiction to supervise and regulate the rates and service of every public utility in this State and to fix just and reasonable standards, classifications, regulations, practices, and measurements of service to be furnished, imposed, or observed, and followed by every public utility in this State.

S.C. Code Ann. § 58-3-140(A). Empowering the Commission to modify a facility fits the general rule that administrative commissions have the power to modify approvals to carry out the goals of the underlying statute, *see U.S. v. State Water Res. Control Bd.*, 182 Cal. App. 3d 82, 130, 227 Cal. Rptr. 161, 188 (Cal. Ct. App. 1986) (finding Commission had implied power to modify permits to include water quality conditions), and that such modifications should be upheld where reasonable and based on evidence, *see In re Narragansett Elec. Co.*, 544 A.2d 121, 127 (R.I. 1988); *Cf. Mueller v. Mo. Hazardous Waste Mgmt. Comm'n*, 904 S.W.2d 552, 559 (Mo. Ct. App. 1995) (refusing to imply power to modify where Commission only had power to resolve appeals of permit issuances or denials).

The power to issue certifications with something more than "small" adjustments comports with the South Carolina Supreme Court's view that the S.C. Public Service Commission "possesses not merely the powers which in terms are conferred upon it, but also such powers as must be inferred or implied in order to enable the agency to effectively exercise the express powers admittedly possessed by it." *Carolina Water Serv., Inc. v. S.C. Pub. Serv. Comm'n*, 272 S.C. 81, 87, 248 S.E.2d 924, 927 (1978) (quoting *Beard-Laney, Inc. v. Darby*, 213 S.C. 380, 389, 49 S.E.2d 564, 567 (1948)). Here, the power to modify and condition certifications as to the construction, operation, and maintenance of a proposed facility is made explicit, with no textual limitation except the Commission acting as it "deem[s] appropriate." S.C. Code Ann. § 58-33-160(1).

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Engrafting judicially-created limitations on that power is inconsistent with the overall intent of the Certification review scheme and the power vested with the Commission. The proposed limitation is also at odds with, and improperly constrains, the Commission's explicit power to impose after-the-fact modifications for temporarily authorized facilities where the Commission "finds such modification necessary in order to minimize the environmental impact," *id.* § 58-33-110(6), and with its power to modify facilities to change their location and provide notice of such changes, *id.* § 58-33-160(2). *Cf. Saxony Lutheran High Sch., Inc. v. Mo. Dep't of Natural Res.*, 404 S.W.3d 902, 911 (Mo. Ct. App. 2013) (finding that presence of a provision for public notice supported view that Commission had power to modify and correct a noncompliant application).

Because the General Assembly gave the Commission the power to condition approvals upon "such terms, conditions or modifications" of "construction, operation or maintenance" as the Commission "may deem appropriate" to minimize environmental impacts, S.C. Code Ann. § 58-33-160(1), that language, and the policy choice it reflects, must be respected. Properly construed, the term "modification" – to alter or change – easily encompasses consideration of Appellants' proposal to include a solar component as an available technology to limit pollution and save ratepayers money. Appellants did not propose to physically alter the facility for which Duke sought a Certificate—a 750 MW combined-cycle natural gas plant. Instead, they proposed something much more modest: that Duke solicit bids from solar companies in the marketplace for solar power to complement the gas plant's operations by allowing Duke to ramp down the gas plant's operations to reduce ratepayer costs and environmental impacts. R. p. 300. Whether the Commission approves of that proposal remains to be seen. Appellants therefore request

that the Court remand this matter so that the Commission may actually consider their proposal.

The Opinion's reading of the term "modification" to preclude consideration of that proposal, based on a single dictionary entry with no reference to the statute, should be reconsidered.

CONCLUSION

For the foregoing reasons, Appellants respectfully request that their petition for rehearing and reconsideration be allowed, that the Court reverse the Commission's grant of a Certificate to Duke, and remand this matter to the Commission.

THE STATE OF SOUTH CAROLINA
In the Court of Appeals

Appellate Case No. 2014-001514

APPEAL FROM THE PUBLIC SERVICE COMMISSION

Docket No. 2013-392-E

In The Matter of Joint Application of Duke Energy Carolinas, LLC and North Carolina Electric Membership Corporation for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of a 750MW Combined Generating Plant Near Anderson, SC

CERTIFICATE OF SERVICE

I certify that I have served Appellants South Carolina Coastal Conservation League and Southern Alliance for Clean Energy's Petition for Rehearing on all parties by depositing a copy in the United States Mail, postage prepaid, on February 23, 2016, addressed to their attorneys of record, as indicated below:

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February 23, 2016

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SC Court of Appeals

VIA FEDERAL EXPRESS
The Honorable Jenny Abbott Kitchings
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1220 Senate Street
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Re: Joint Application of Duke Energy Carolinas
Appellate Case No. 2014-001514

Dear Ms. Kitchings:

Enclosed for filing please find the original and seven (7) copies of Appellants South Carolina Coastal Conservation League and Southern Alliance for Clean Energy's Petition for Rehearing and Certificate of Service in the above-referenced matter. Also enclosed is a check in the amount of $25.00 to cover the associated filing fee. Please return a file-stamped copy to our office in the enclosed self-addressed, stamped envelope.

By copy of this correspondence, I am serving the same upon all counsel of record. If you have any questions or if there is anything further I should provide, please do not hesitate to contact me at 843-720-5270 or bholman@selcsc.org.

Thank you kindly for your assistance with this matter.

Sincerely,

J. Blanding Holman IV

JBH/arp

cc: All Counsel of Record (via First Class Mail)

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The South Carolina Court of Appeals

In the Matter of Joint Application of Duke Energy Carolinas, LLC and North Carolina Electric Membership Corporation for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of a 750MW Combined Generating Plant Near Anderson, SC.

Appellate Case No. 2014-001514

ORDER

After careful consideration of the petition for rehearing, the Court is unable to discover that any material fact or principle of law has been either overlooked or disregarded, and hence, there is no basis for granting a rehearing. Accordingly, the petition for rehearing is denied.

_____ C.J.

_____ J.

_____ J.

Columbia, South Carolina

FILED
March 24, 2016

cc:
James Blanding Holman, IV, Esquire
Christopher Kaltman DeScherer, Esquire
Len Sullivan Anthony, Esquire
Richard Lee Whitt, Esquire

Timika Shafeek-Horton, Esquire
Nanette Solveig Edwards, Esquire
Shannon Bowyer Hudson, Esquire
Jacquelyn Sue Dickman, Esquire
Frank Rogers Ellerbe, III, Esquire
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Susan Annelle Lake, Esquire