DUKE ENERGY®
CAROLINAS

Duke Energy Carolinas

Integrated Resource Plan (Annual Report)

October 15, 2013

Public

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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 3 NG Conversion; Nuclear Uprates	170; 32
2016	-	-
2017	New CC; Nuclear Uprates	680; 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.

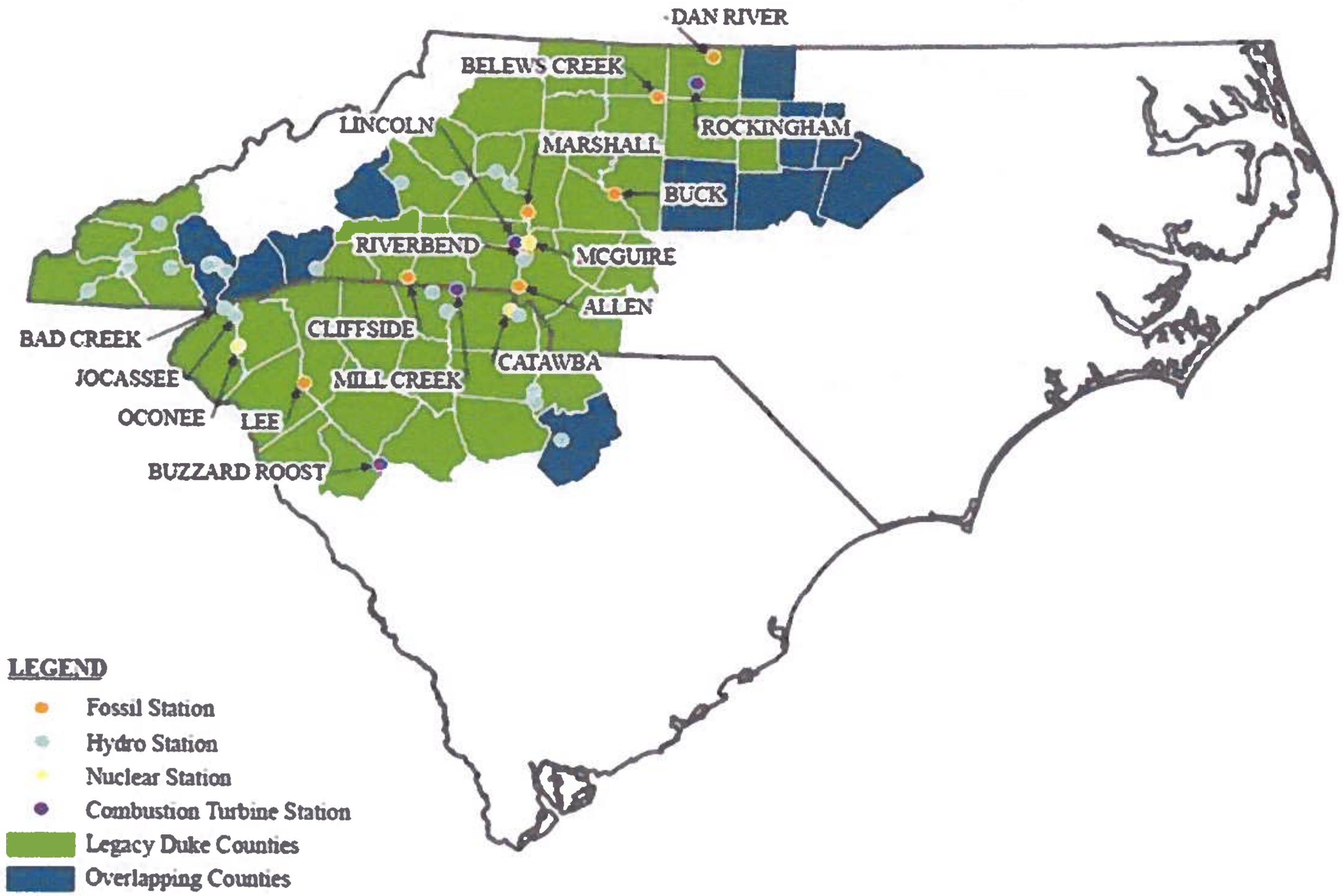
DEC currently meets energy demand, in part, by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:

- 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).

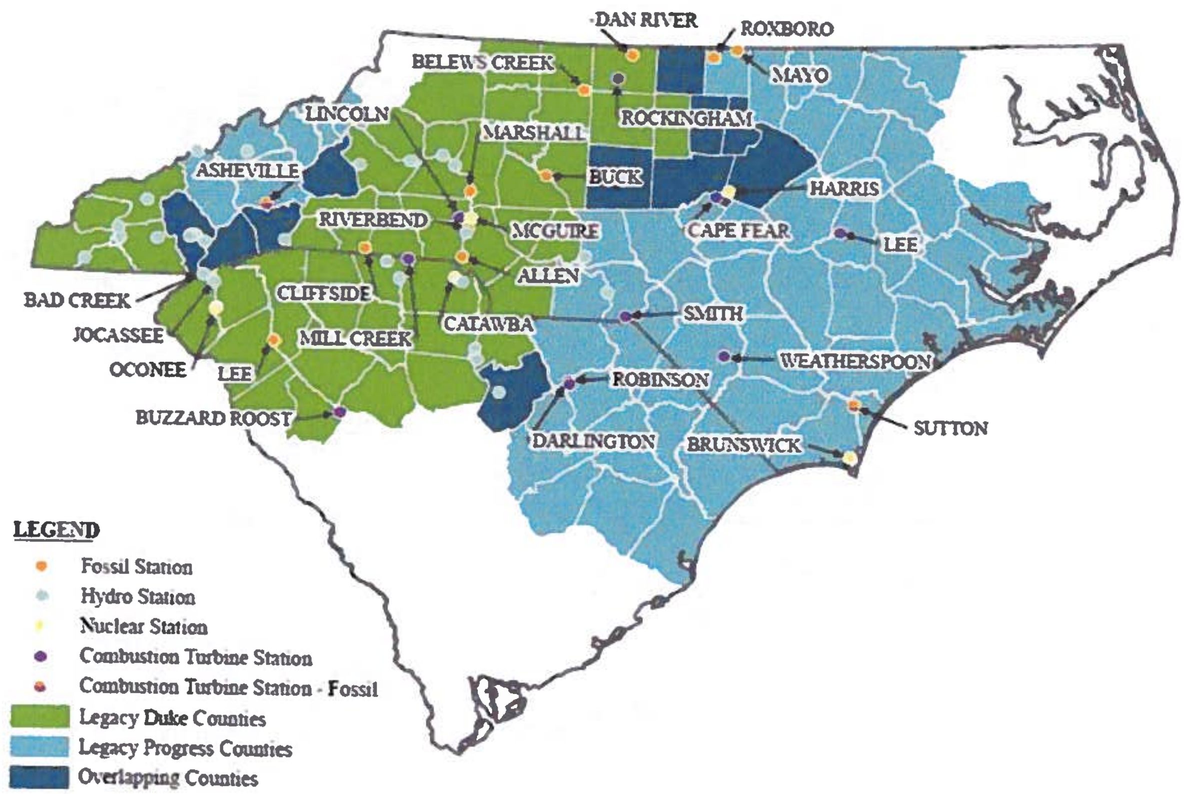
The map on the following page provides a high-level view of the DEC service area.

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

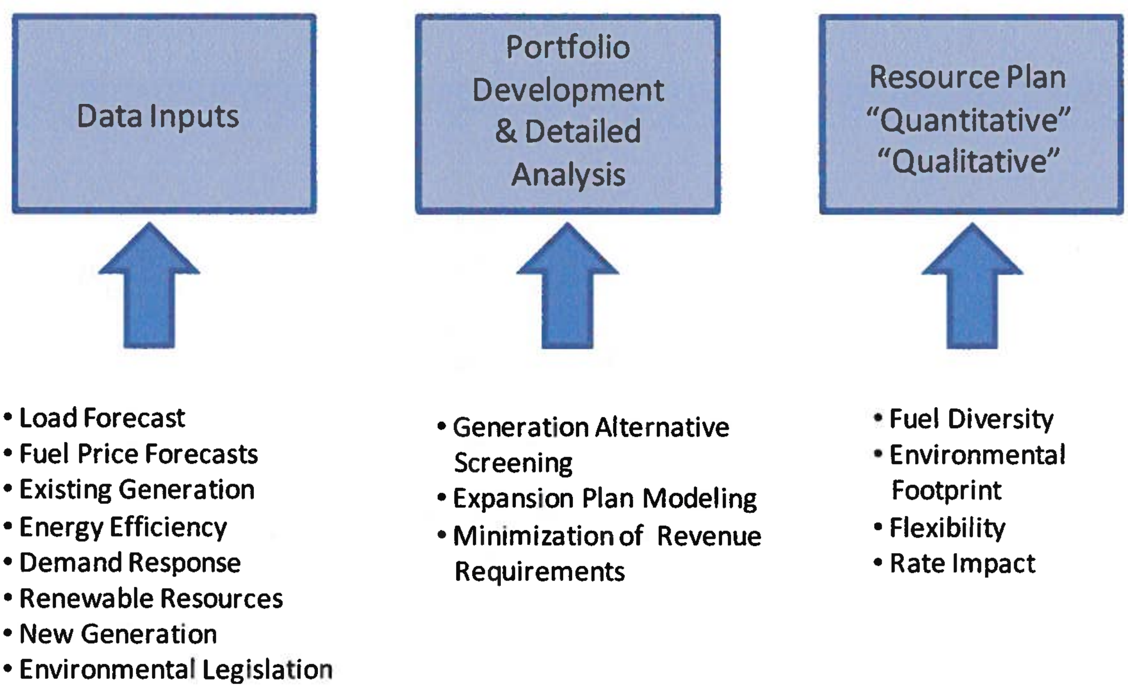
DEC's resource plan reflects reserve margins ranging from 14 to 22%. Reserves projected in DEC's IRP meet the minimum planning reserve margin target and thus satisfy the one day in 10 year LOLE criterion. Projected reserve margins exceed the minimum 14.5% target by 3% or more in 2019 as a result of the 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.

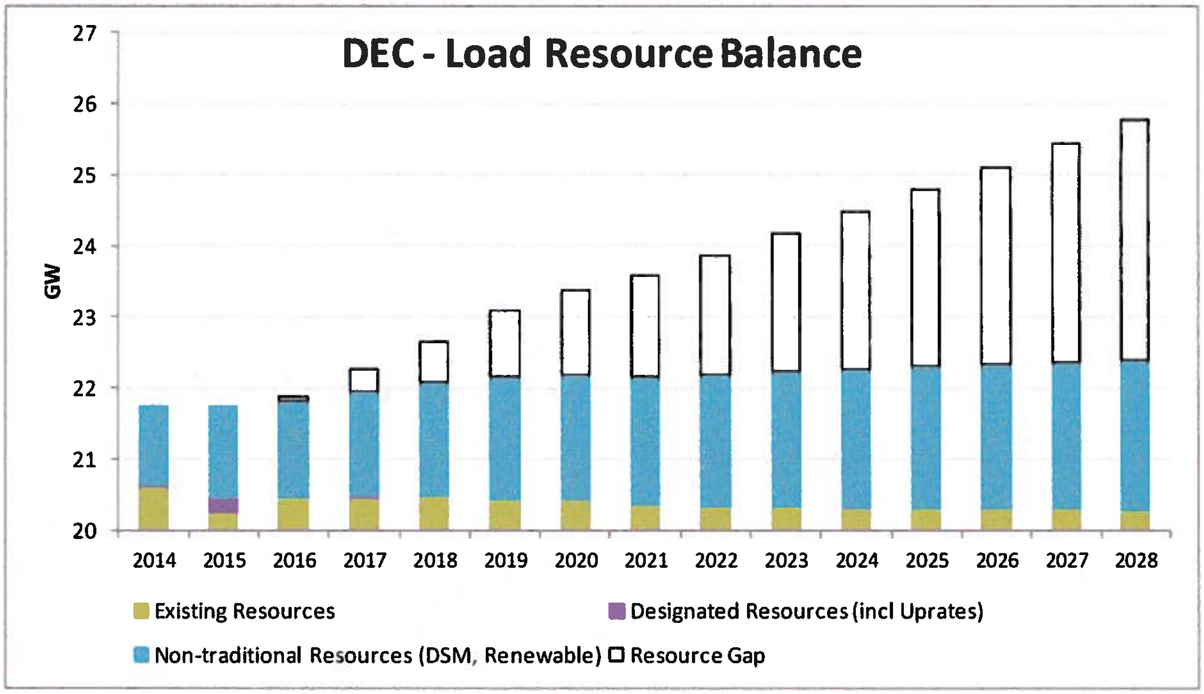
Resource Plans

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

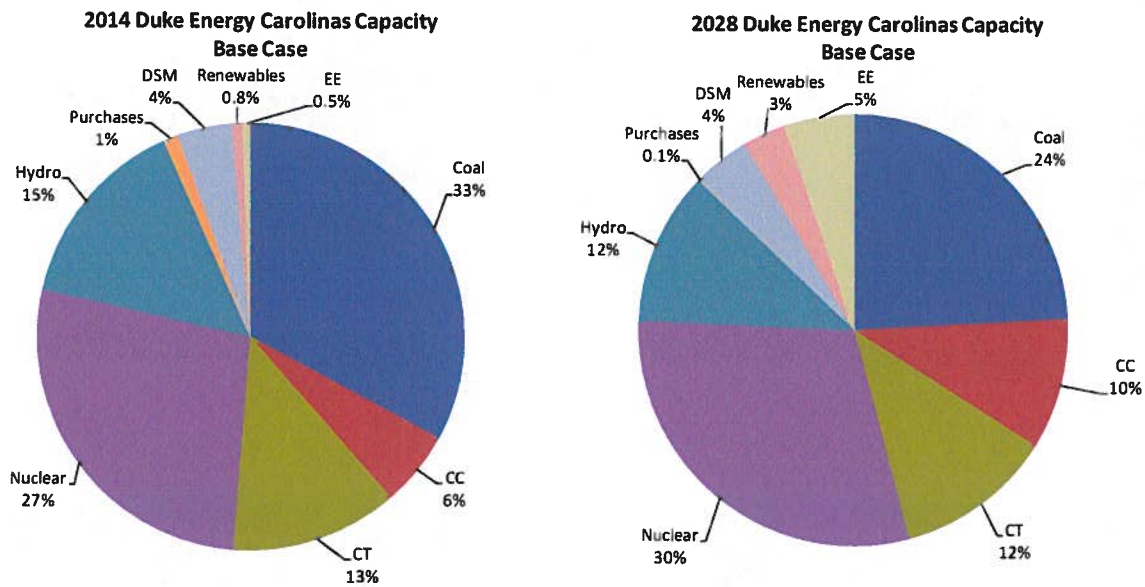
15. Sum of lines 13 and 14

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	-	-

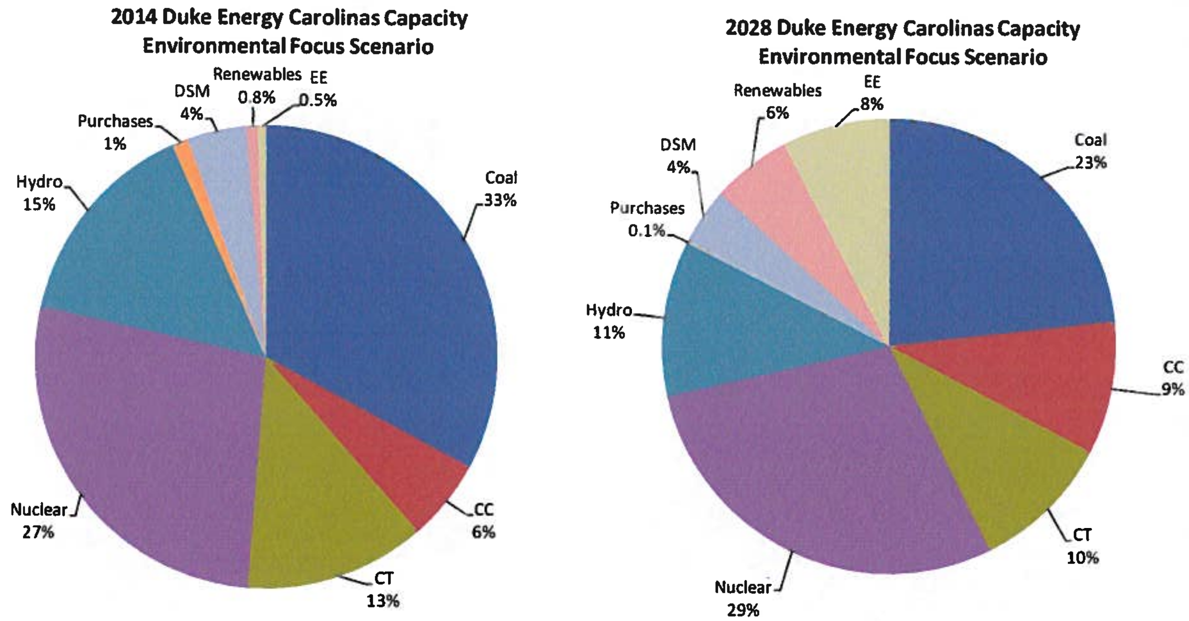
Note: Tables represent only undesignated resources from 2018 through 2028, no changes to the Base Case build plan occurred in prior years

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; 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

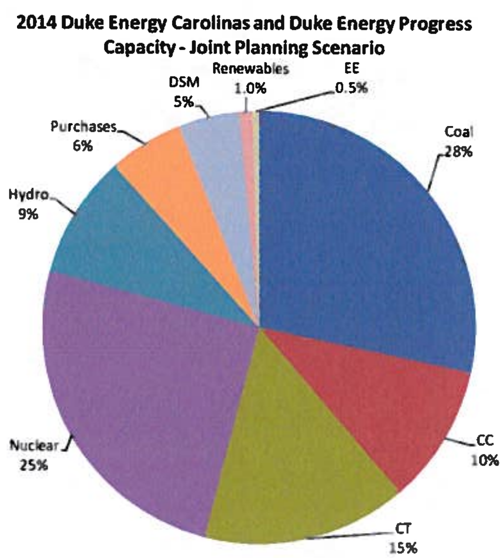
Duke Energy Carolinas and Duke Energy Progress Joint Planning Scenario Resource Plan

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

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



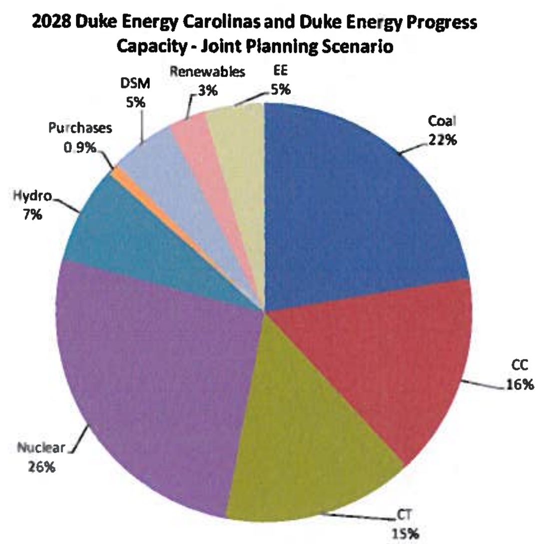
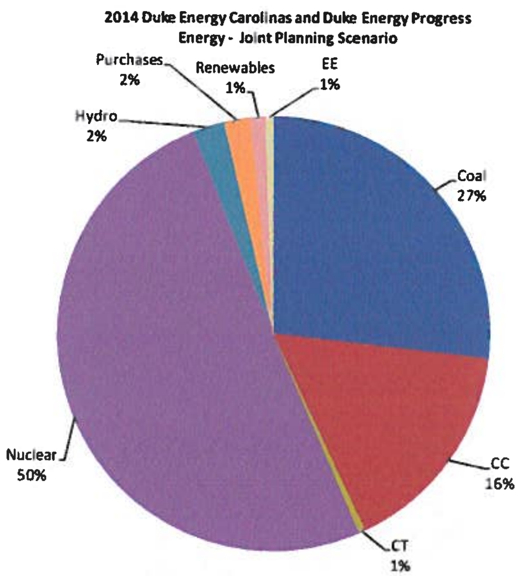
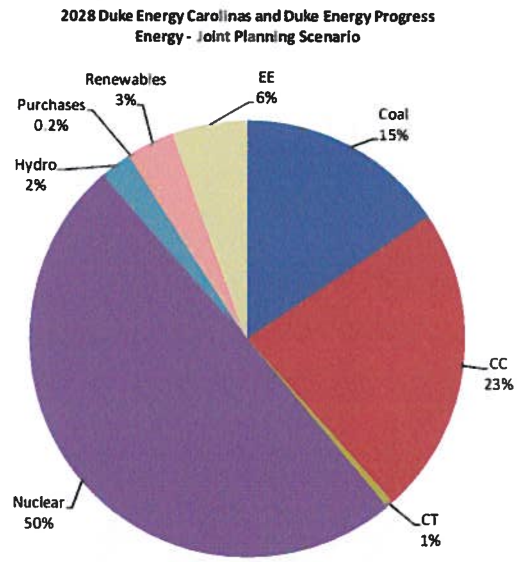


Chart 8-J DEC and DEP Energy by Fuel Type – Joint Planning Scenario





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

<u>Supply-Side</u>

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

- Baseload – 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 o 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

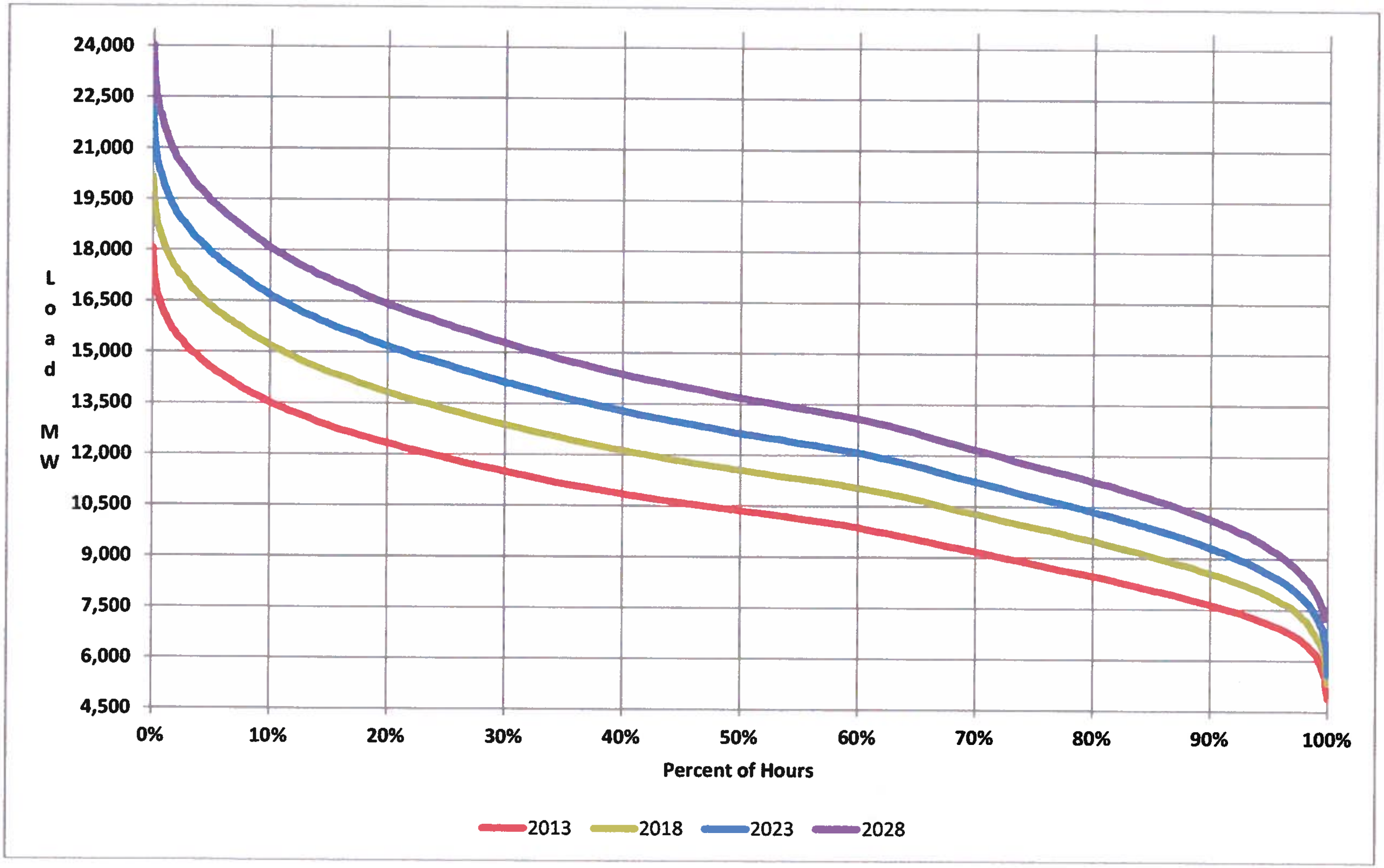
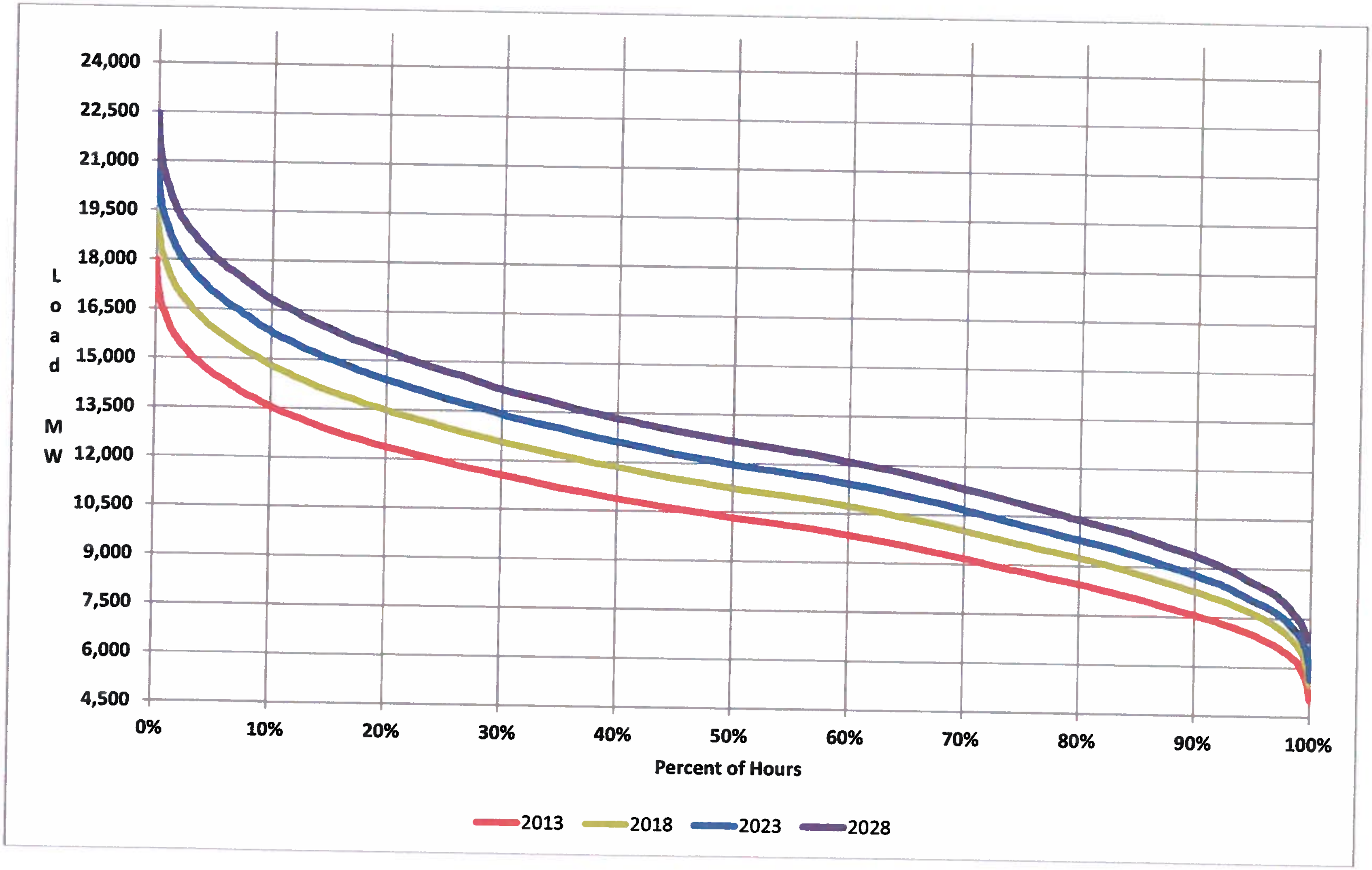


Table C-6
Load Forecast with Energy Efficiency Programs

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.

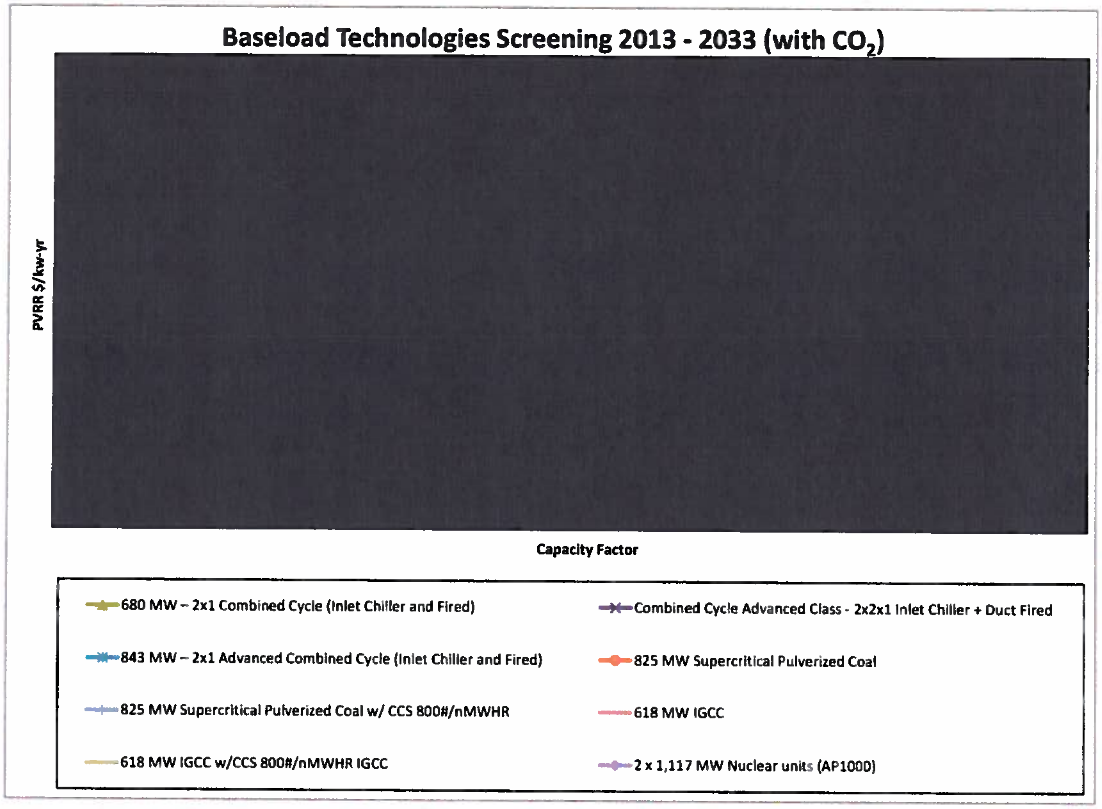
Screening Results

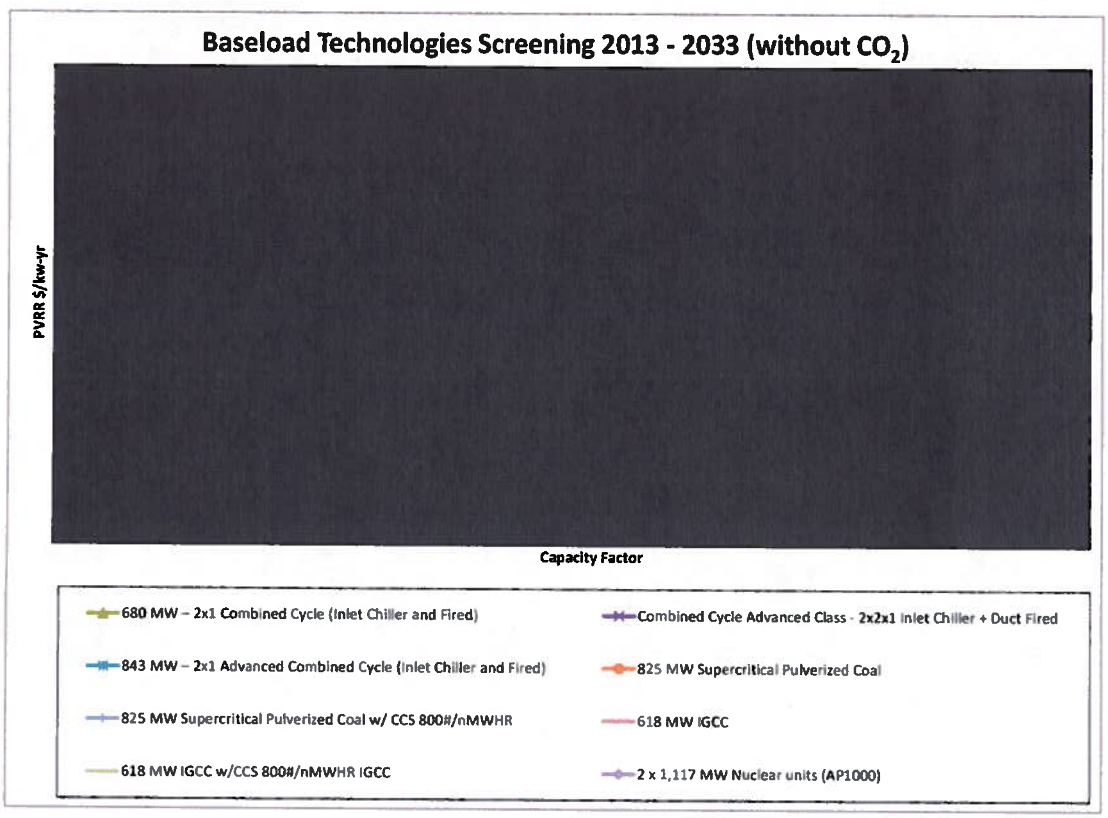
The results of the screening within each category are shown in the figures below. Results of the baseload screening show that combined cycle generation is the least-cost baseload resource. With lower gas prices, larger capacities and increased efficiency, combined cycle units have become more cost-effective 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.


Baseload Technologies Screening 2013 - 2033 (with CO_2)
[redacted]
PVRR $/kw-yr
Capacity Factor
680 MW – 2x1 Combined Cycle (Inlet Chiller and Fired)
Combined Cycle Advanced Class - 2x2x1 Inlet Chiller + Duct Fired
843 MW – 2x1 Advanced Combined Cycle (Inlet Chiller and Fired)
825 MW Supercritical Pulverized Coal
825 MW Supercritical Pulverized Coal w/ CCS 800#/nMWHR
618 MW IGCC
618 MW IGCC w/CCS 800#/nMWHR IGCC
2 x 1,117 MW Nuclear units (AP1000)


Baseload Technologies Screening 2013 - 2033 (without CO_2)
[redacted]
PVRR $/kw-yr
Capacity Factor
680 MW – 2x1 Combined Cycle (Inlet Chiller and Fired)
Combined Cycle Advanced Class - 2x2x1 Inlet Chiller + Duct Fired
843 MW – 2x1 Advanced Combined Cycle (Inlet Chiller and Fired)
825 MW Supercritical Pulverized Coal
825 MW Supercritical Pulverized Coal w/ CCS 800#/nMWHR
618 MW IGCC
618 MW IGCC w/CCS 800#/nMWHR IGCC
2 x 1,117 MW Nuclear units (AP1000)

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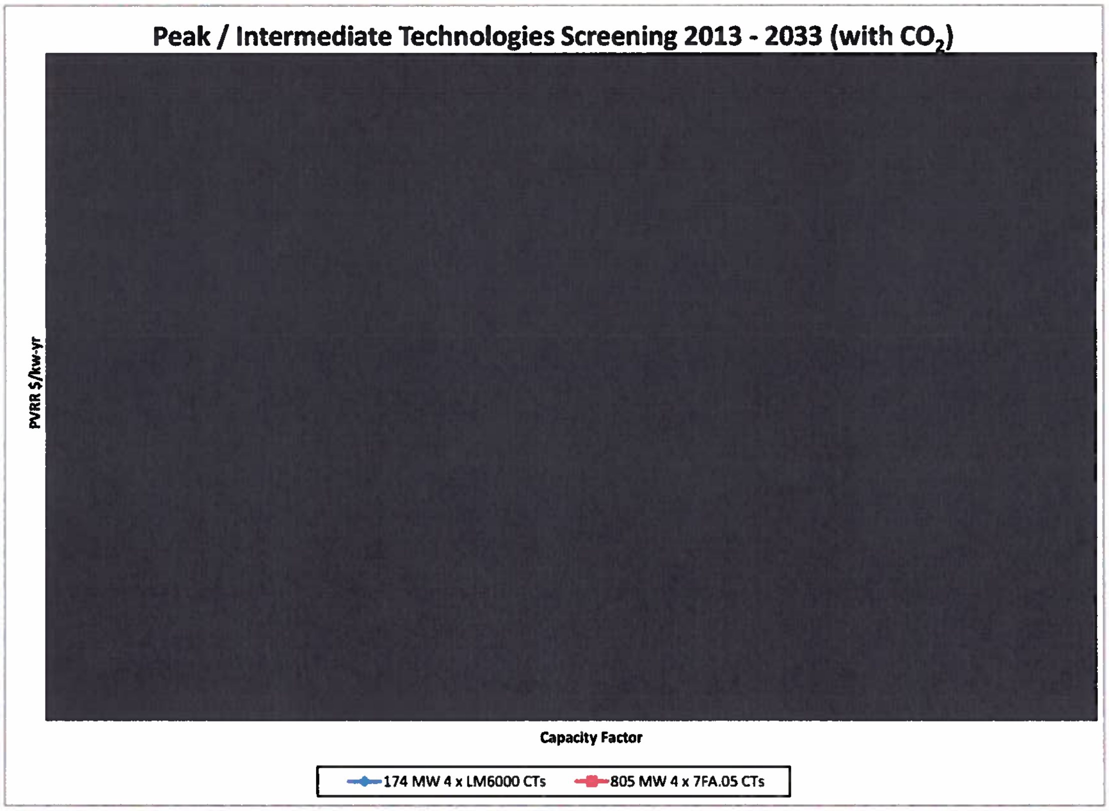

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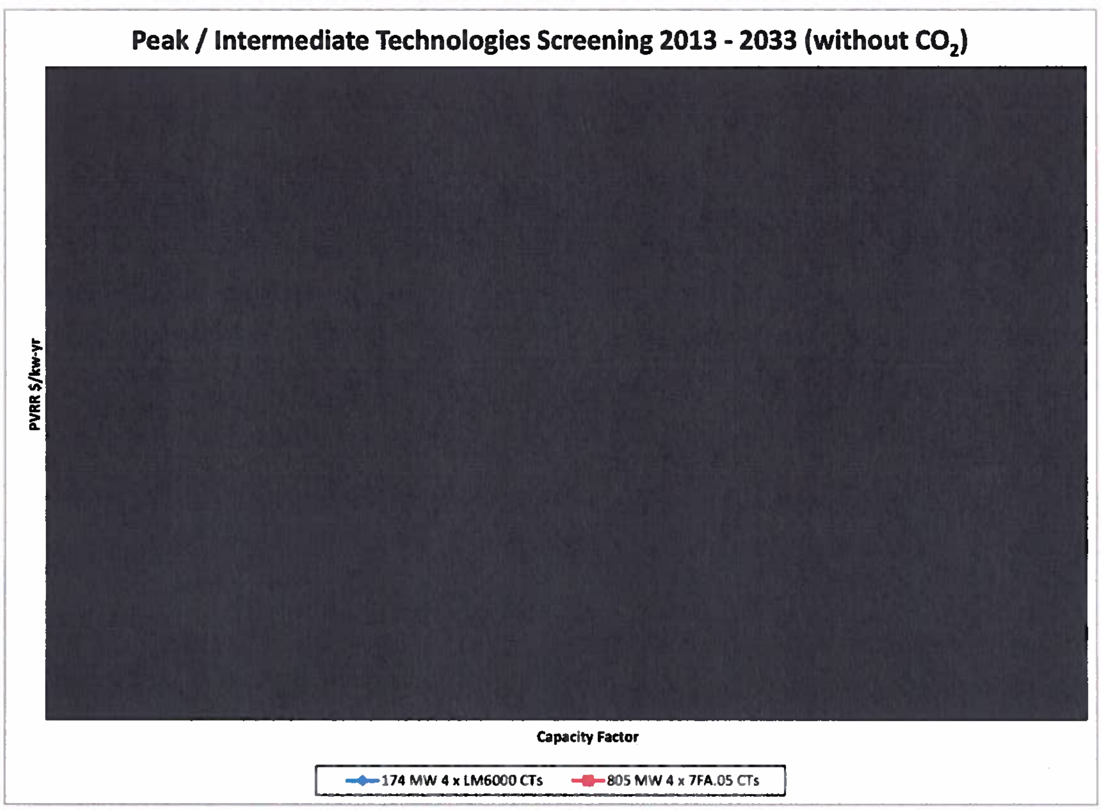
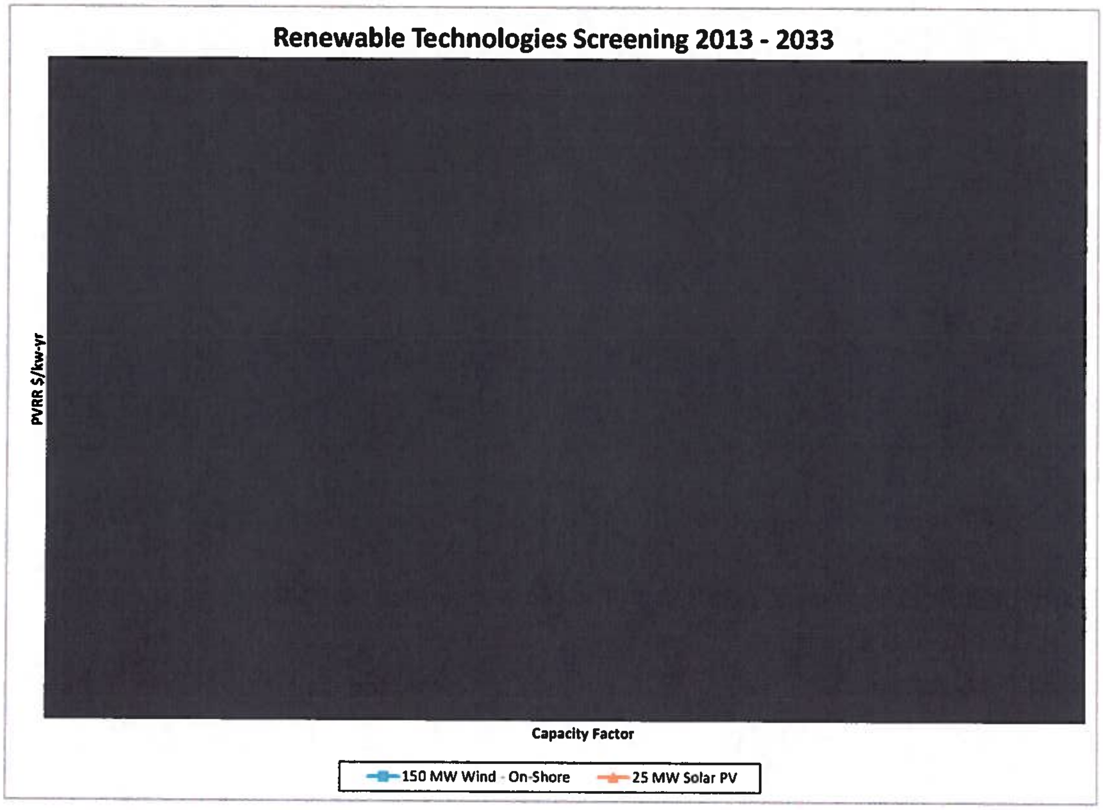



Renewable Technologies Screening 2013 - 2033
PVRR $/kw-yr
Capacity Factor
150 MW Wind - On-Shore
25 MW Solar PV

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

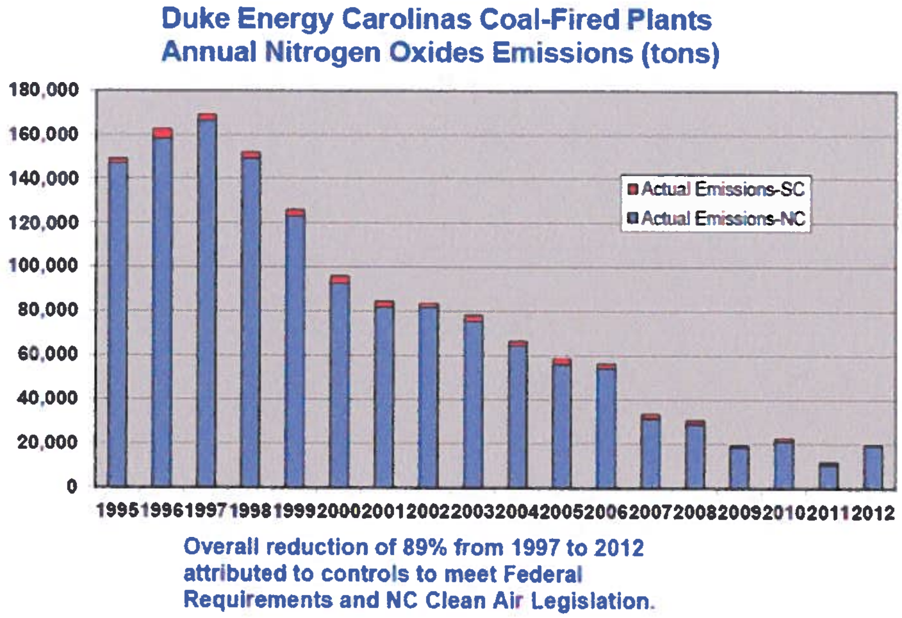
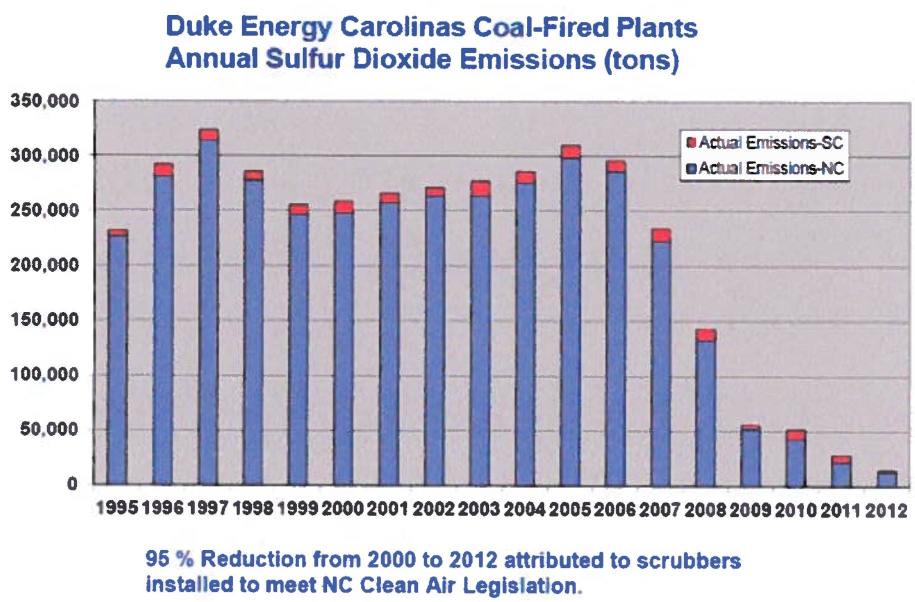


Chart G-2 DEC SO_2 Emissions



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
Table of Contents

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

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[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				
[redacted]	5 years*	[redacted]		
	20 Years*			
	10 Years			
	5 Years			
	5 Years*			
	5 Years			
	5 Years*			
	15 Years			
	20 Years*			
	15 Years*			
	20 Years*			
Total Solar REC Purchases		[redacted]		

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

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

* 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