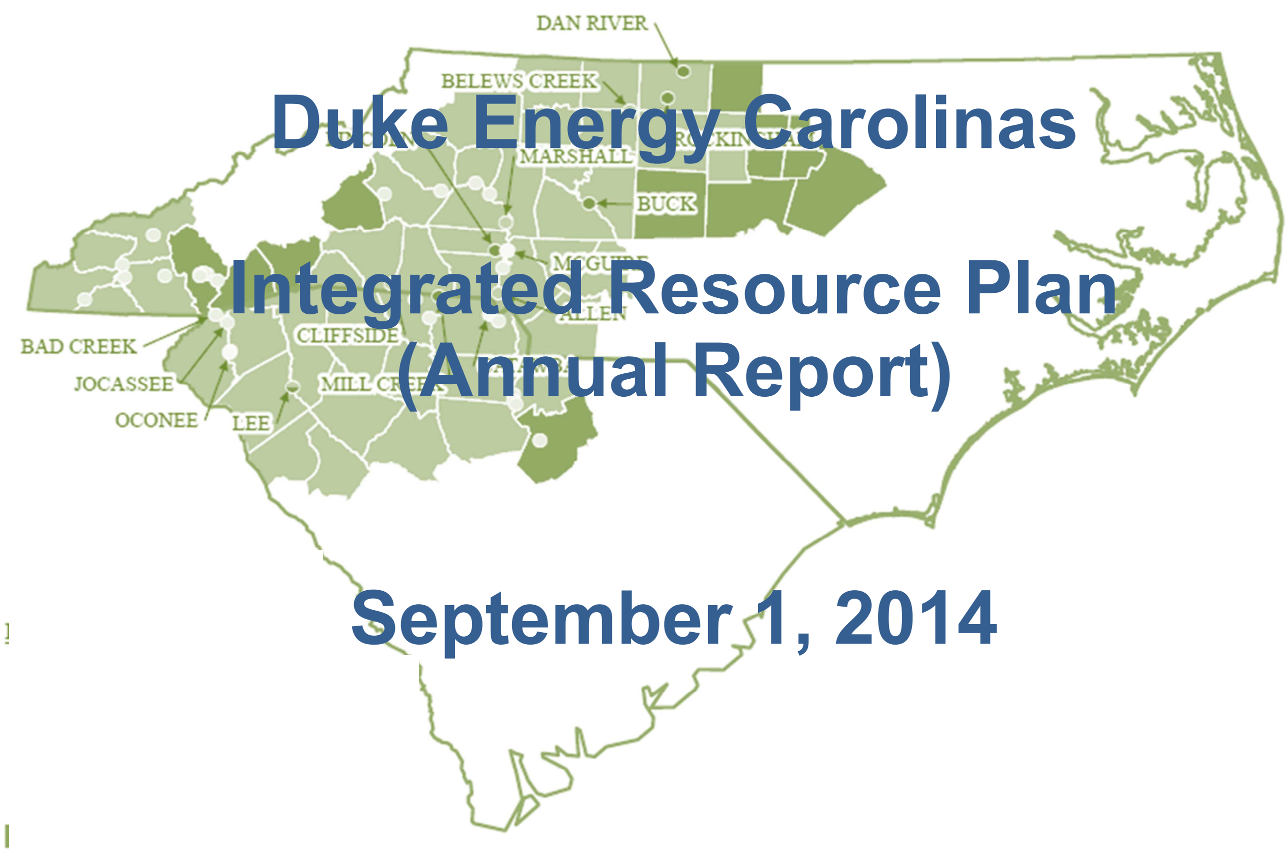
DUKE ENERGY® CAROLINAS



Duke Energy Carolinas

Integrated Resource Plan (Annual Report)

September 1, 2014

Public

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ABBREVIATIONS	
BCFD	Billion Cubic Feet Per Day
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAPP	Central Appalachian Coal
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 Programs
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
FPS	Feet Per Second
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
MGD	Million Gallons Per Day
NAAQS	National Ambient Air Quality Standards
NAP	Northern Appalachian Coal
NC	North Carolina
NCCSA	North Carolina Clean Smokestacks Act
NCDAQ	North Carolina Division of Air Quality
NCEMC	North Carolina Electric Membership Corporation
NCMPA1	North Carolina Municipal Power Agency #1
NCTPC	NC Transmission Planning Collaborative
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
OATT	Open Access Transmission Tariff
PD	Power Delivery
PEV	Plug-In Electric Vehicles
PMPA	Piedmont Municipal Power Agency
PPA	Purchase Power Agreement
PPB	Parts Per Billion
PSCSC	Public Service Commission of South Carolina
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
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
UG/M^3	Micrograms Per Cubic Meter
UCT	Utility Cost Test
VACAR	Virginia/Carolinas
VAR	Volt Ampere Reactive

1. EXECUTIVE SUMMARY

Overview

For more than a century, Duke Energy Carolinas (DEC) has provided affordable and reliable electricity to customers in North Carolina and South Carolina now totaling more than 2.4 million in number. Each year, as required by the North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC), DEC submits a long-range planning document called the Integrated Resource Plan (IRP) detailing potential infrastructure needed to match the forecasted electricity requirements for our customers over the next 15 years.

The 2014 IRP is the best projection of how the Company's energy portfolio will look over the next 15 years, based on current data assumptions. This projection will change as variables such as projected load forecasts, fuel prices, new environmental regulations and other outside factors change.

The proposed plan will meet the following objectives:

- Provide reliable electricity during peak demand periods by maintaining adequate reserve margins. Peak demand refers to the highest amount of electricity being consumed at any point in time across DEC's entire system.
- Add new resources at the lowest reasonable cost to customers. These resources include energy efficiency (EE) programs, demand-side management programs (DSM), renewable resources, nuclear facilities and natural gas generation.
- Meet or exceed all Federal, State and local environmental regulations.

The Road Ahead— Determining Customer Electricity Needs 2015 – 2029

The 2014 IRP identifies the incremental amount of electricity our customers will require over the next 15 years using the following basic formula:

Growth in Customer Energy Consumption + **Resource Retirements** = **New Resource Needs**

The energy consumption annual growth rate for all customers is forecasted to be 1.5%. The growth rate is offset by projections for increased EE impacts, reducing the projected growth rate by 0.5% for a net growth rate of 1.0%after accounting for energy efficiency. Peak demand growth net of EE is expected to grow slightly faster than overall consumption with an average projected growth rate of 1.4%.

Projected electricity consumption growth rates by customer class are as follows:

- Commercial class is the fastest growing class with a projected growth rate of 1.5%.
- Industrial class has a projected growth rate of 0.6%.
- Residential class has a projected growth rate of 1.1%.

In addition to customer growth, plant retirements and expiring purchased power contracts create the need to add incremental resources to allow the Company to reliably meet future customer demand. Over the last several years, aging, less efficient coal plants have been replaced with a combination of renewable energy, EE, DSM and state-of-the art natural gas generation facilities.

The Company will soon be closing its last coal facility not equipped with advanced emission controls. In April 2015, Lee Steam Station Units 1 and 2 in Anderson County, S.C will be shuttered. Unit 3 will be converted to natural gas. These closings are the last in a series of coal unit retirements totaling approximately 1,700 MW of cumulative retirements. In addition, DEC has retired approximately 400 MW of older combustion turbine (CT) units.

Investment Strategy to Meet Customer Needs

Natural Gas

The 2014 IRP identifies the need for new natural gas plants that are economic, highly efficient and reliable. The planning document outlines the following relative to new natural gas resources. Locations for most of these facilities have not been finalized:

- Convert 170 MW Lee Steam Unit 3 from coal to natural gas in 2015.
- Complete construction of the 770 MW natural gas combined cycle plant at Lee Steam Station, Anderson County, SC, expected to be commercially available by the end of 2017.
- Consider an 866 MW natural gas combined cycle in 2020.
- Consider 792 MW of combustion turbine resources in 2028.

Nuclear Power

The 2014 IRP continues to support new nuclear generation as a carbon-free, cost-effective, reliable option within the Company's resources portfolio. The current base plan calls for the following:

- Complete all steps needed to secure a Combined Construction and Operating License (COL) from the Nuclear Regulatory Commission (NRC) for the W.S. Lee Nuclear Station (Lee Nuclear), Cherokee, SC.

- Commercial operation of the first unit at the Lee Nuclear Station by 2024.
- Review the potential need for additional new nuclear capacity by 2033 in advance of the Oconee license expiration.
- Study the possibility of an additional license extension at the Oconee Nuclear Station that would allow for operations beyond the current sixty-year license, which expires in the 2033-34 time frame.

Renewable Energy and Solar Resources

Renewable mandates, substantial tax subsidies and declining costs make solar energy the Company's primary renewable energy resource within the 2014 IRP. DEC continues to add solar energy to its resource mix through Purchased Power Agreements (PPAs), Renewable Energy Credit (REC) purchases and utility-owned solar generation. The 2014 IRP calls for:

- Increasing solar energy resources from 480 MW in 2015 to 1,681 MW in 2029.
- Complying with NC Renewable Energy and Energy Efficiency Portfolio Standards (NC REPS) through a combination of solar, other renewables, EE and REC purchases.
- Planning for incremental renewables above NC REPS as a result of new supportive legislation in South Carolina and the potential future additional State and/or Federal incentives or technology cost declines.

While the Company is aggressively pursuing solar as a renewable resource, the 2014 IRP recognizes and plans for its operational limitations. Solar energy is an intermittent renewable energy source. It cannot be dispatched to meet changing demand from customers all hours of the day and night, through all types of weather. As such, solar energy in combination with traditional resources like natural gas or nuclear plants must be part of the Company's diverse resource portfolio.

In general, by way of comparison:

- Solar energy's equivalent full output is available approximately 20% of the time.
- Nuclear energy's equivalent full output is available greater than 90% of the time.
- Natural gas combined cycle's energy is available greater than 90% of the time.

As a result, it can take 4 to 5 MW of installed solar generation to produce the same amount of energy that is available from a single MW of natural gas or nuclear generation. So while solar's total contribution is somewhat limited relative to traditional supply alternatives, it is considered an important component of DEC's resource mix.

Energy Efficiency and Demand-Side Management

New EE and DSM programs approved in 2014 are supporting efforts to reduce the annual forecasted demand growth over the next 15 years. Aggressive marketing campaigns have been launched to make customers aware of DEC's 20 EE and DSM programs, successfully increasing customer adoption. The Company is forecasting continued energy and capacity savings from both EE and DSM programs through the planning period as depicted in the table below.

Table Exec-1: DEC Projected EE and DSM Energy and Capacity Savings

Projected EE and DSM Energy and Capacity Savings		
Year	**Energy (MWh)**	**Capacity (MW)**
2015	664,000	1,173
2029	7,668,000	2,475

Cost-effective EE and DSM programs efficiently reduce the Company's need to construct new generation resources and purchase fuel to operate those resources. The Base Case shows the current projections for cost-effective achievable savings. Even greater savings may be possible depending on variables such as customer participation and future technology innovations. Alternative resource portfolios with these higher levels are presented in Appendix A.

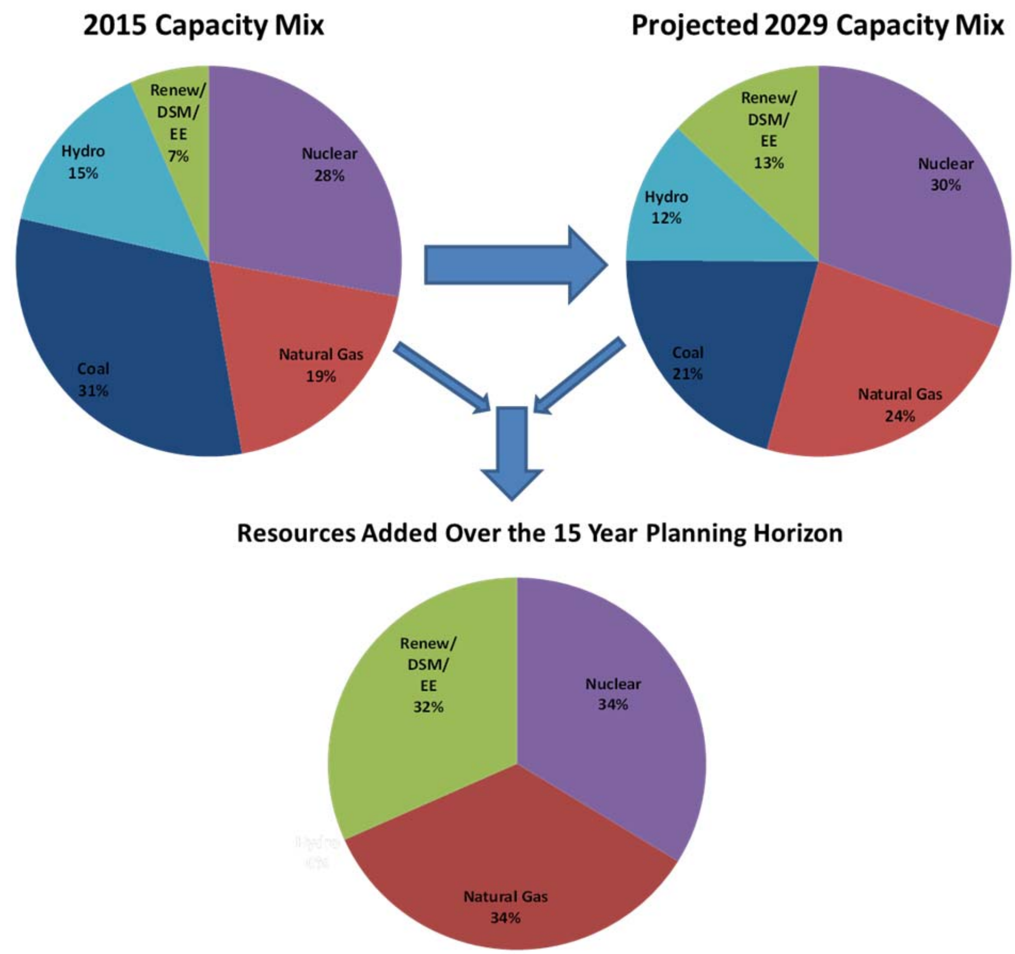
Strong Trend Toward Cleaner, More Environmentally Friendly Generation

When viewed in total, more than 55% of the energy that DEC will supply in 2015 originates from emission-free resources. This includes previously mentioned nuclear energy, hydro-electric power, DSM, EE and renewable energy.

The remaining 45% of the energy portfolio continues to shift toward clean, efficient natural gas units and coal plants that are equipped with state-of-the-art emission technology. Based upon the proposed Environmental Protection Agency (EPA) carbon standards for new generation, the 2014 IRP does not call for the construction of any new coal plants.

The figure below illustrates how the Company's capacity mix is expected to change over the planning horizon. As shown in the bottom pie chart, DSM, EE and renewables will combine to meet one-third of the Company's projected incremental peak demand needs. The plan also calls for approximately one third of future resources to come from new natural gas generation with the final third coming from nuclear generation. In aggregate, the incremental resource additions identified in the 2014 IRP contribute to an economic, reliable and increasingly clean energy portfolio for the Company's customers.

Figure Exec-1: 2015 & 2029 Capacity Mix and Sources of Incremental Capacity Additions



Identifying Resource Options for Further Consideration

This report is intended to provide stakeholders insight into the Company's planning process for meeting forecasted customer peak demand and cumulative energy needs over the 15-year planning horizon. Such stakeholders include: legislative policymakers, public utility commissioners and their staffs, residential, commercial and industrial retail customers, wholesale customers, environmental advocates, renewable resource industry groups and the general public. A more detailed presentation of the Base Case, as described in the above Executive Summary, is included in this document in Chapter 8 and Appendix A.

The following chapters provide an overview of the inputs, analysis and results included in the 2014 IRP. In addition to the Base Case, four different resource portfolios were analyzed under multiple sensitivities. Finally, the appendices to the document give even greater detail and specific information regarding the input development and the analytic process utilized in the 2014 IRP.

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 2.43 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.

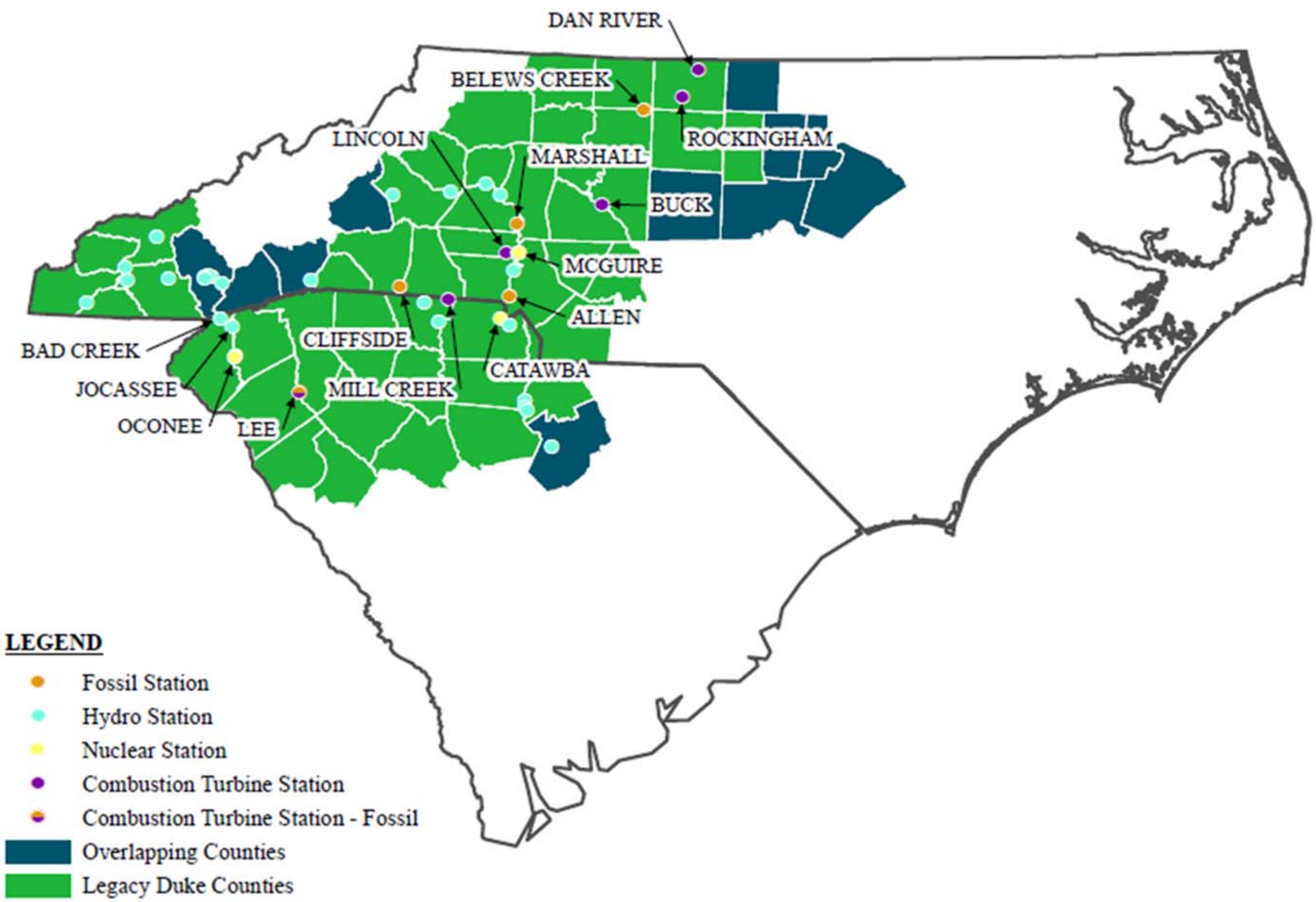
DEC currently meets energy demand, in part, by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:

- Three nuclear generating stations with a combined capacity of 7,122 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 3,238 MW
- Six CT stations and two CC stations with a combined capacity of 4,038 MW

The Company's power delivery system consists of approximately 102,300 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, Smoky 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).

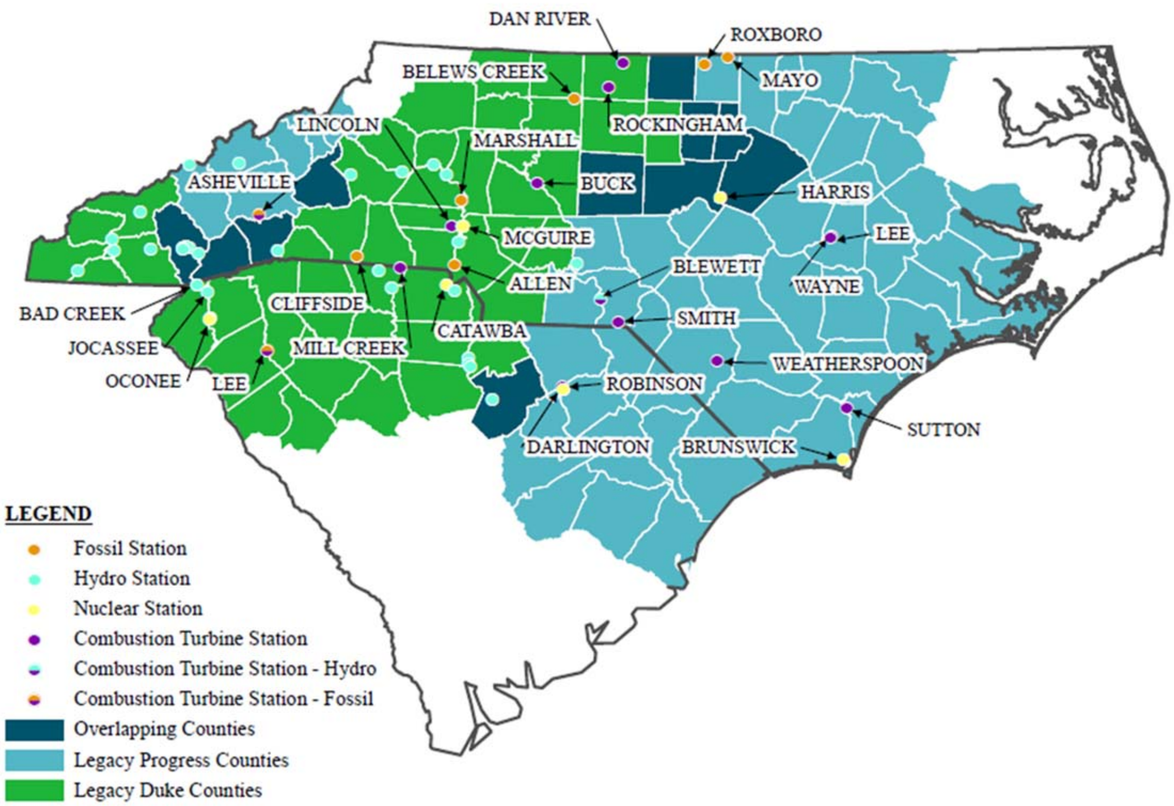
The map on the following page provides a high-level view of the DEC service area.

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 territories of the Companies are shown in the map below.

Chart 2-B DEC and DEP Service Area



3. ELECTRIC LOAD FORECAST

The Duke Energy Carolinas' spring 2014 forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2015 – 2029 and represents the needs of the retail and wholesale customers that DEC is contractually obligated to serve.

Energy projections are developed with econometric models using key economic factors such as income, electricity prices, industrial production indices, along with weather and appliance efficiency trends. Population is also used in the residential customer model. 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 2014 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 was derived using a Statistical Adjusted End-Use Model (SAE). This is a regression-based framework that uses projected appliance saturation and efficiency trends developed by Itron using Energy Information Administration (EIA) data. It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models. The outlook for usage per customer is essentially flat through much of the forecast horizon, so most of the growth is primarily due to customer increases. The projected energy growth rate of residential in the spring 2014 forecast after all adjustments for utility EE programs, solar and electric vehicles from 2015-2029 is 1.1%.

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 energy growth rate of 1.5%, after adjustments.

The industrial class forecast is impacted by the level of manufacturing output, exchange rates, electric prices and weather. Overall, industrial energy usage is expected to grow 0.6% over the forecast horizon, after adjustments.

Peak Demand and Energy Forecast

If the impacts of new Duke Energy Carolinas energy efficiency programs are included, the projected compound annual growth rate for the summer peak demand for retail and wholesale over the planning horizon is 1.4%, while winter peaks are forecasted to grow at a rate of 1.5%. The forecasted compound annual growth rate for energy is 1.0% after the impacts of energy efficiency programs are subtracted.

The spring 2014 forecast is lower than the spring 2013 forecast, with summer peak growth of 1.5% in the spring 2013 forecast versus 1.4% in the new forecast. It is lower mainly due to a slightly slower economic outlook. These growth rates reflect the impacts of EE.

The load forecast projection for energy and capacity including the impacts of EE that was utilized in the 2014 IRP is shown in Table 3-A.

Table 3-A Load Forecast with Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWh)
2015	18,486	17,303	95,763
2016	18,822	17,637	97,329
2017	19,130	17,982	98,789
2018	19,448	18,317	100,271
2019	19,806	18,672	101,484
2020	20,076	18,882	102,221
2021	20,291	19,105	102,873
2022	20,529	19,322	103,515
2023	20,777	19,570	104,150
2024	21,085	19,883	104,983
2025	21,320	20,158	105,618
2026	21,595	20,440	106,399
2027	21,906	20,721	107,713
2028	22,276	21,083	109,158
2029	22,537	21,346	110,555

Note: Table 8-C differs from these values due to 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, DEC advocates a balanced solution to meeting future energy needs in the Carolinas. That balance includes a strong commitment to energy efficiency and demand side management.

Since 2009, DEC has been actively developing and implementing new EE and DSM programs throughout its North Carolina and South Carolina service areas to help customers reduce their electricity demands. DEC's EE and DSM plan is 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 EE/DSM 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 from State utility commissions to implement EE and DSM 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 PSCSC 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.

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. 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.

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, NC, 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 EE, DSM and consumer education programs, which also includes a discussion of the methodology for determining the cost effectiveness of EE and DSM programs. Smart Grid-related demand response impacts are also discussed in Appendix D.

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 in Docket E-7, Sub 986. 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 2014 IRP. However, it is being treated as an aspirational target for the development of future EE plans and programs. As such, the aspirational EE target is included in the quantitative analysis phase of this IRP to examine the economic and operational impacts of this level of EE when also coupled with a high level of renewable energy resources.

5. RENEWABLE ENERGY REQUIREMENTS

Renewable resources such as wind and solar are considered within the IRP planning process as potential resources to meet DEC's customer energy and capacity needs. In addition, 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 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 2014 IRP that a new legislative or regulatory 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 2019 and would gradually increase to a 12.5% level by 2027. 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 but would not contain additional technology-specific set-asides or a cost-cap feature.

South Carolina recently passed legislation allowing the Company to apply to the PSCSC for approval to participate in a Distributed Energy Resource (DER) program. The Company has not yet filed for approval of a new DER program, but anticipates that such a program would encourage additional distributed energy resources in the Company's South Carolina territory over the coming years. The Company notes that the additional requirements assumed in the Company's plan provide for more renewable resources than the SC legislation would provide through the DER Plan included in the SC legislation.

The Company has assessed the current and potential future costs of renewable and traditional technologies. Based on this analysis, the IRP modeling process yielded no incremental renewable energy resources that will be developed over the planning horizon beyond those needed to meet existing and anticipated statutory renewable energy requirements described above. However, in sensitivities in which the projected price of renewable resources was reduced, additional renewables were selected. In those sensitivities, substantial reductions in capital cost would be required for solar to be selected as opposed to traditional supply side resources. A detailed discussion of these sensitivities is provided in Appendix A.

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 1,248 MW (nameplate) of compliance renewable capacity will be interconnected to the DEC system by 2021, with that figure growing to approximately 2,144 MW by the end of the planning horizon in 2029. Actual results could vary substantially depending on future legislative requirements, supportive tax policies, technology cost trends and other market forces, but the Company anticipates a diverse portfolio including solar, wind, biomass, hydro, and other resources.

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 2014 IRP, the contribution to peak values that were utilized were 46% of nameplate for solar and 13% 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
2015	0	171	102	274		0	373	102	475
2016	0	206	110	316		0	448	110	557
2017	0	217	106	324		0	472	106	579
2018	0	229	92	321		0	497	92	589
2019	0	286	128	414		0	621	128	750
2020	20	355	158	533		150	771	158	1079
2021	20	419	187	625		150	911	187	1248
2022	20	479	211	709		150	1041	211	1402
2023	20	537	243	799		150	1167	243	1560
2024	20	590	272	882		150	1283	272	1706
2025	20	644	289	953		150	1400	289	1839
2026	20	693	304	1017		150	1507	304	1962
2027	20	738	313	1071		150	1605	313	2068
2028	20	764	327	1110		150	1661	327	2138
2029	20	768	324	1112		150	1670	324	2144

Total renewable resources included in the 2014 Base Case IRP is somewhat larger than what is presented in Table 5-A. Below in Table 5-A.1 provides the total renewable resources, which includes both compliance renewable resources as well as non-compliance renewable purchases.

Non-compliance renewable purchases result from Qualified Facilities (QFs) that the Company is required to purchase under the Public Utilities Regulatory Policies Act (PURPA). Qualified facilities that do not sell renewable energy certificates to the Company are captured in the IRP as non-compliance renewable purchases.

Table 5-A.1 DEC Base Case Total Renewables (Compliance & Non-compliance)

DEC Renewables									
	MW Contribution to Summer Peak					MW Nameplate			
	Wind	Solar	Biomass/ Hydro	Total		Wind	Solar	Biomass/ Hydro	Total
2015	0	221	126	347		0	480	126	607
2016	0	255	128	383		0	554	128	683
2017	0	263	124	387		0	572	124	696
2018	0	275	106	381		0	597	106	703
2019	0	331	141	472		0	719	141	860
2020	20	400	171	590		150	869	171	1190
2021	20	464	200	683		150	1009	200	1359
2022	20	524	224	767		150	1139	224	1512
2023	20	582	253	855		150	1265	253	1668
2024	20	635	283	937		150	1381	283	1814
2025	20	689	300	1008		150	1498	300	1947
2026	20	738	315	1073		150	1605	315	2070
2027	20	783	324	1126		150	1702	324	2175
2028	20	807	327	1153		150	1754	327	2231
2029	20	773	324	1117		150	1681	324	2155

Summary of Renewable Energy Planning Assumptions

The Company's assumptions relating to renewable energy requirements (existing and anticipated) included in the 2014 IRP are largely similar to the assumptions in DEC's 2013 IRP.

DEC continues to expect the development and interconnection of significant quantities of solar resources over the planning horizon, driven by continued declines in the installed cost of solar as a result of increased industry scale, standardization, and technological innovation. Some 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 compliance efforts beyond the solar set-aside minimum threshold for NC REPS, and in the corresponding compliance assumptions for 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, although, land-based wind in the U.S. has benefitted from supportive Federal tax policies no longer in effect. Although the Company expects to rely upon wind resources for REPS compliance, the extent and timing changes depending upon supporting policies and prevailing market prices. The Company has also 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.

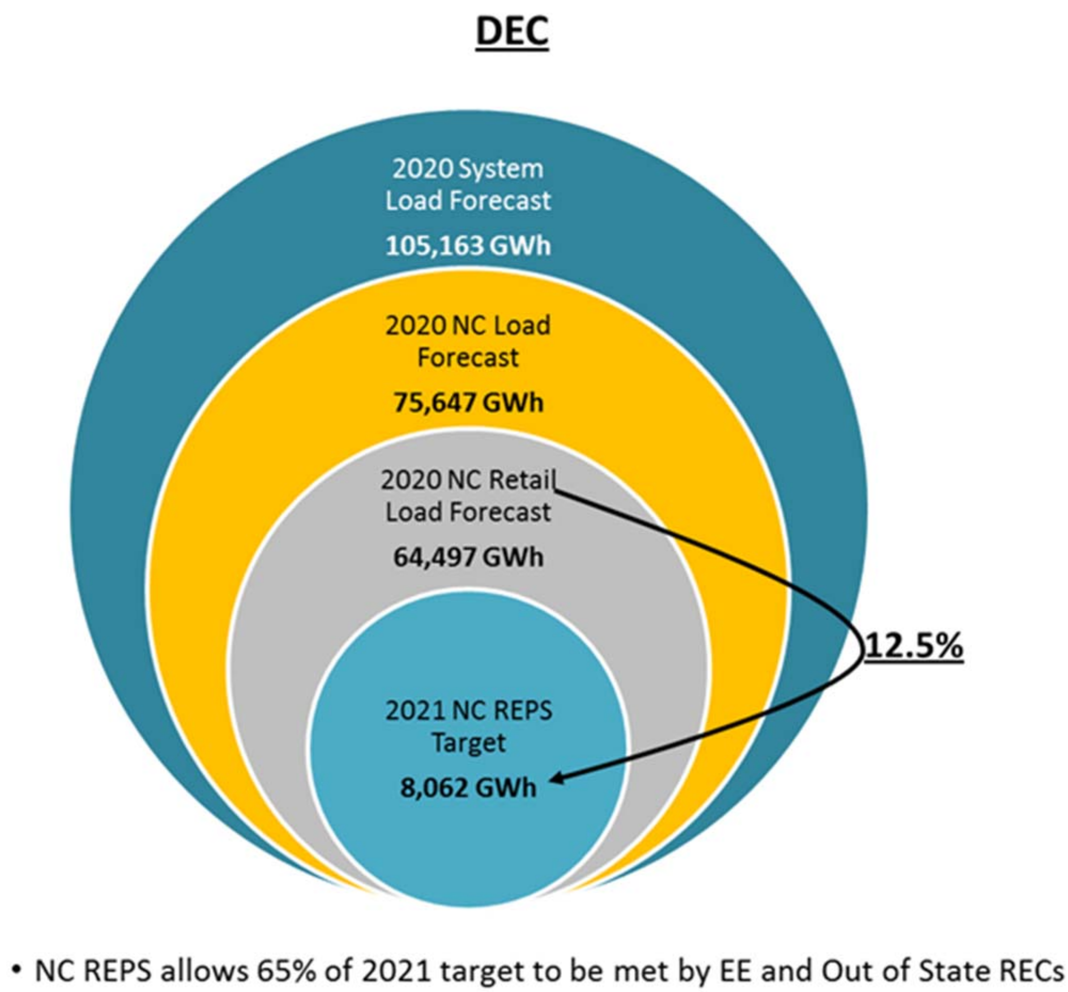
In general, the Company expects a mix of resources will ultimately be used for meeting renewable targets, with the specifics of that mix determined in large part by policy developments over the coming five to ten years. Costs for all the resources discussed above are highly dependent upon future subsidies, 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. Each of the portfolios considered in the IRP process include resources to fully comply with NC REPS.

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, REPS requirement of meeting 12.5% of NC Retail Energy by 2021 is derived as shown in Figure 5-A below.

Figure 5-A: Meeting NC REPS Requirements



Additionally, 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 both State and Federal incentives scheduled to decline over the coming years, 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 IRP evaluates two of the five resource portfolios under market conditions reflective of higher penetrations of renewable resources and energy efficiency as compared to the Base Case. These portfolios do not envision a specific market condition, but rather merely consider 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, these portfolios assume a requirement for DEC to serve approximately 10% of its total combined retail load with new renewable resources by 2030. This represents over twice the amount of renewable energy as compared to the Base Case. Additionally, EE is incorporated at an aspirational target level as established in the Merger Settlement Agreement. As presented in the table below, the High EE/Renewables portfolios include additional renewables of approximately 3,418 MW nameplate (1,481 MW contribution to peak) in DEC as compared to the Base Case. Table 5-B below provides the renewable energy resources assumed in the High EE/Renewables portfolios.

Table 5-B DEC High Renewables (Compliance and Non-compliance Purchases)

DEC Renewables									
	MW Contribution to Summer Peak					MW Nameplate			
	Wind	Solar	Biomass/ Hydro	Total		Wind	Solar	Biomass/ Hydro	Total
2015	0	221	126	347		0	480	126	607
2016	0	255	128	383		0	554	128	683
2017	0	263	124	387		0	572	124	696
2018	0	275	106	381		0	597	106	703
2019	0	331	141	472		0	719	141	860
2020	23	544	171	738		178	1183	171	1532
2021	27	753	200	979		205	1637	200	2042
2022	30	957	224	1211		233	2081	224	2538
2023	34	1160	253	1447		261	2521	253	3035
2024	38	1358	283	1678		289	2951	283	3523
2025	41	1556	300	1897		316	3382	300	3998
2026	45	1750	315	2109		344	3804	315	4462
2027	48	1939	324	2311		372	4215	324	4910
2028	52	2107	327	2486		399	4581	327	5307
2029	56	2218	324	2598		427	4823	324	5574

6. SCREENING OF GENERATION ALTERNATIVES

As previously discussed, the Company develops the load forecast and adjusts for the impacts of EE programs 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 2014 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 CCS, CTs, CCs with inlet chillers and duct firing, and nuclear units. In addition, Duke Energy Carolinas considered renewable technologies such as wind, solar, and landfill gas in the screening analysis.

For the 2014 IRP screening analysis, 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 evaluated in the screening analysis phase of the IRP process. The technical and economic screening is discussed in detail in Appendix F.

- Base load – 723 MW Supercritical Pulverized Coal with CCS
- Base load – 525 MW IGCC with CCS
- Base load – 2 x 1,117 MW Nuclear units (AP1000)
- Base load – 688 MW – 2x2x1 Combined Cycle (Inlet Chiller and Duct Fired)
- Base load – 866 MW – 2x2x1 Advanced Combined Cycle (Inlet Chiller and Duct Fired)
- Base load – 1,302 MW – 3x3x1 Advanced Combined Cycle (Inlet Chiller and Duct Fired)
- Peaking/Intermediate – 173 MW 4-LM6000 CTs
- Peaking/Intermediate – 792 MW 4-7FA CTs
- Renewable – 150 MW Wind - On-Shore
- Renewable – 5 MW Landfill Gas
- Renewable – 25 MW Solar Photovoltaic (PV)

7. RESERVE CRITERIA

Background

The reliability of energy service is a primary goal 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 years 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

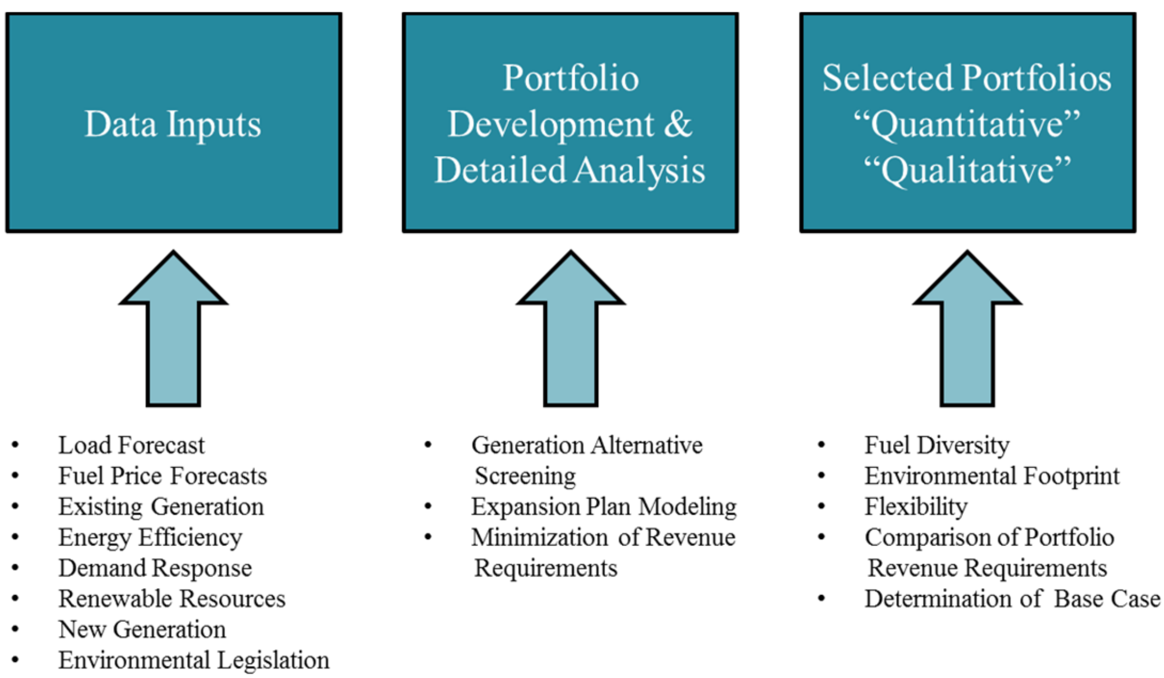
DEC's resource plan reflects reserve margins ranging from 15 to 23%. Reserves projected in DEC's IRP meet the minimum planning reserve margin target and thus satisfy the one day in 10 years LOLE criterion. The projected reserve margin exceeds the minimum 14.5% target by 3% or more in 2015 primarily as a result of a reduction in the load forecast. Projected reserve margins also exceed the target by 3% or more in 2020 and 2021 as a result of the economic addition of a large combined cycle facility in 2020 and in 2024-2027 as a result of the economic addition of large baseload additions in 2024 and 2026. Similarly, the projected reserve margin exceeds 3% or more of the target in 2028 as a result of the economic addition of a large block of CT capacity. 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 cumulative energy sales and hourly peak demand. To determine total resources needed, the Company considers the peak demand 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 and planning reserve margin while complying with all environmental and regulatory requirements. It should be noted that DEC considers the non-firm energy purchases and sales associated with the Joint Dispatch Agreement (JDA) with DEP in the development of its independent Base Case and four alternative portfolios as discussed later in this chapter and in Appendix A.

Figure 8-A represents a simplified overview of the resource planning process. The IRP Process and development of the Base Case and additional portfolios are discussed in more detail in Appendix A.

Figure 8-A Simplified IRP Process



Data Inputs

The initial step in the IRP development process is one of input data refreshment and revision. For the 2014 IRP, data inputs such as load forecast, EE and DSM projections, fuel prices, projected CO_2 prices, individual plant operating and cost information, and future resource information were updated with the most current data. These data inputs were developed and provided by Company subject matter experts and/or based upon vendor studies, where available. Furthermore, DEC and DEP continue to benefit from the combined experience of both utilities' subject matter experts 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 IRP 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 are examined in more detail in the appendices.

- Load Forecast for Customer Demand
- EE/DSM
- Renewable Resource Cost Projections
- Fuel Costs Forecasts
- Technology Costs and Operating Characteristics
- Environmental Legislation and Regulation
- Nuclear Issues

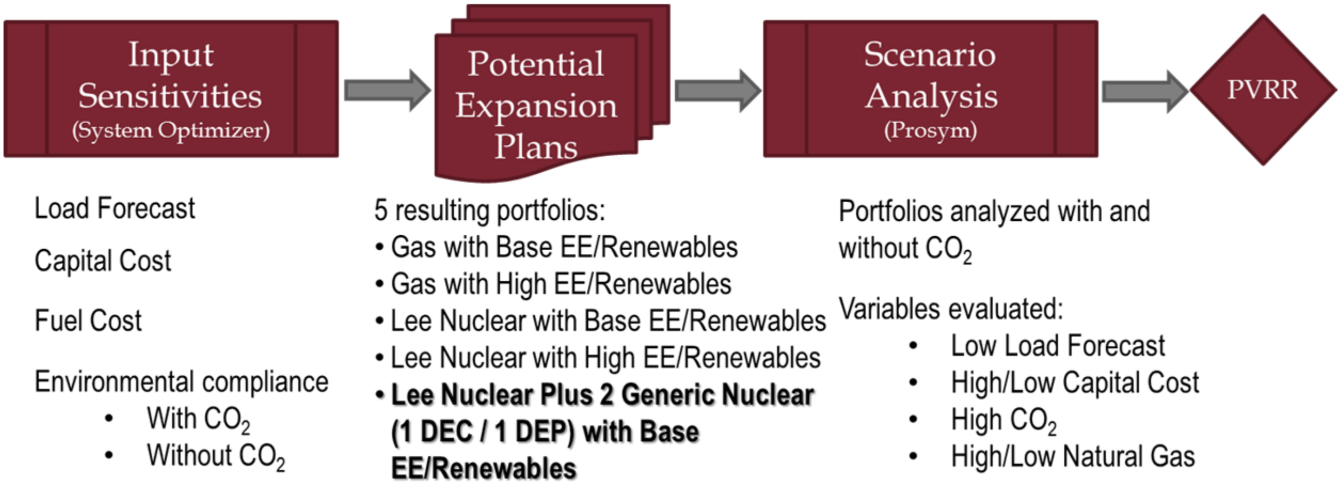
Generation Alternative Screening

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

Portfolio Development and Detailed Analysis

The following figure provides an overview of the process for the portfolio development and detailed analysis phase of the IRP.

Figure 8-B Overview of Portfolio Development and Detailed Analysis Phase



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 simulation modeling is to determine the best mix of capacity additions for the Company's short- and long-term resource needs with an objective of selecting a robust plan that minimizes the PVRR and is environmentally sound complying with all State and Federal regulations.

Sensitivity analysis of input variables such as load forecast, fuel costs, renewable energy, EE, and capital costs are considered as part of the quantitative analysis within the resource planning process. Utilizing the results of these sensitivities, portfolios that are representative of possible expansion plan options for the DEC system are developed and the portfolios' economics are analyzed. Finally, the portfolios are analyzed under scenarios that represent both a carbon-constrained future (With CO_2) and a future without carbon constraints (No CO_2) in order to evaluate the robustness and economic value of each portfolio.

In addition to evaluating these portfolios solely within the DEC system, the potential benefits of sharing capacity within DEC and DEP are examined in a common Joint Planning Case. A detailed discussion of these portfolios is provided in Appendix A.

Selected Portfolios

For the 2014 IRP, the sensitivity analysis within the potential expansion plans step resulted in five representative portfolios, which were developed, from the sensitivity analysis of the data inputs. Three resource portfolios were developed with base levels of energy efficiency and renewable resources. These three portfolios included: 1) a no new nuclear portfolio, 2) a two unit Lee Nuclear portfolio, and 3) Lee Nuclear plus two additional nuclear units (1 DEC / 1 DEP) beyond the 15 year planning horizon. Two additional resource portfolios were developed by evaluating the no nuclear portfolio and the Lee Nuclear portfolio in an environment with higher amounts of EE and renewables as discussed in Chapters 4 and 5. Table 8-A provides a listing of the portfolios that were evaluated with base input assumptions in the 2014 IRP and their relative PVRR ranking in both the With CO_2 and No CO_2 scenarios.

Table 8-A: Portfolios Developed Under Base Input Assumptions

Portfolio	Portfolio Description	PVRR Ranking (With CO_2)	PVRR Ranking (No CO_2)
1	No Nuclear with Base EE/Renewables	2	1
2	Lee Nuclear with Base EE/Renewables	3	2
3	Lee Nuclear + 2 New Nuclear (1 in DEC / 1 in DEP) with Base EE/Renewables	1 - Base Case	3
4	No Nuclear with High EE/Renewables	4	4
5	Lee Nuclear with High EE/Renewables	5	5

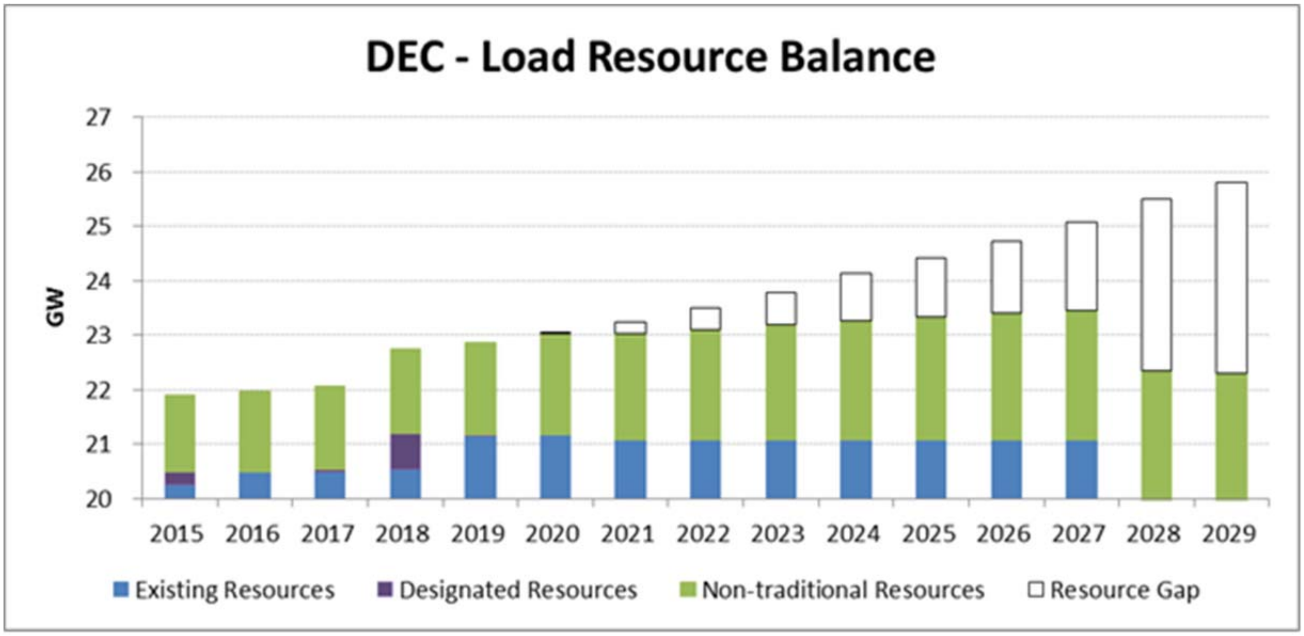
Based on the PVRR Rankings, the robustness of the portfolio, and the belief that there will be some type of carbon legislation in the future, Portfolio #3 With CO_2 was selected as the Base Case in the 2014 IRP.

Base Case

The Base Case was selected based upon the evaluation of the portfolios in the With CO_2 scenario. The Base Case was developed utilizing consistent assumptions and analytic methods between DEC and DEP, where appropriate. This case 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. A Joint Planning Case that begins to explore the potential for DEC and DEP to share firm capacity was also developed and is discussed later in this chapter and in Appendix A.

The Load and Resource Balance Chart shown in Chart 8-A illustrates the resource needs that are required for DEC to meet its load obligation inclusive of a required reserve margin. The existing generating resources, designated resource additions and EE resources do not meet the required load and reserve margin beginning in 2020. As a result, the resource plan analyses have determined the most robust plan to meet this resource gap.

Chart 8-A DEC Base Case Load Resource Balance



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

Year	2015	2016	2017	2018	2019	2020	2021	2022
Resource Need	0	0	0	0	0	16	202	409
Year	2023	2024	2025	2026	2027	2028	2029	
Resource Need	605	876	1,074	1,324	1,626	3,160	3,509	

Tables 8-B and 8-C present the Load, Capacity and Reserves tables for the Base Case analysis that was completed for DEC's 2014 IRP.

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

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2014 Annual Plan

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Load Forecast															
1 Duke System Peak	18,635	19,033	19,407	19,792	20,219	20,563	20,815	21,146	21,492	21,896	22,232	22,597	22,987	23,425	23,748
2 Firm Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(101)	(164)	(230)	(297)	(366)	(440)	(524)	(617)	(715)	(811)	(912)	(1,002)	(1,081)	(1,149)	(1,211)
4 Adjusted Duke System Peak	**18,533**	**18,869**	**19,177**	**19,495**	**19,853**	**20,123**	**20,291**	**20,529**	**20,777**	**21,085**	**21,320**	**21,595**	**21,906**	**22,276**	**22,537**
Existing and Designated Resources															
5 Generating Capacity	20,449	20,311	20,311	20,356	21,026	21,036	21,042	21,042	21,042	21,042	21,042	21,042	21,042	21,042	19,915
6 Designated Additions / Uprates	232	0	45	670	10	6	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	(370)	0	0	0	0	0	0	0	0	0	0	0	0	(1,127)	0
8 Cumulative Generating Capacity	**20,311**	**20,311**	**20,356**	**21,026**	**21,036**	**21,042**	**21,042**	**21,042**	**21,042**	**21,042**	**21,042**	**21,042**	**21,042**	**19,915**	**19,915**
Purchase Contracts															
9 Cumulative Purchase Contracts	**243**	**237**	**233**	**230**	**189**	**186**	**100**	**81**	**79**	**79**	**79**	**79**	**78**	**56**	**5**
Non-Compliance Renewable Purchases	73	68	64	60	58	58	58	58	56	55	55	55	55	43	5
Non-Renewables Purchases	169	169	169	169	131	128	42	24	24	24	24	24	24	14	0
Undesignated Future Resources															
10 Nuclear	0	0	0	0	0	0	0	0	0	1,117	0	1,117	0	0	0
11 Combined Cycle	0	0	0	0	0	866	0	0	0	0	0	0	0	0	0
12 Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0	0	792	0
Renewables															
13 Cumulative Renewables Capacity	274	316	324	321	414	533	626	710	799	882	953	1,018	1,071	1,111	1,112
14 Cumulative Production Capacity	**20,828**	**20,864**	**20,912**	**21,576**	**21,639**	**22,626**	**22,633**	**22,698**	**22,786**	**23,986**	**24,057**	**25,238**	**25,291**	**24,974**	**24,924**
Demand Side Management (DSM)															
15 Cumulative DSM Capacity	**1,072**	**1,095**	**1,142**	**1,180**	**1,213**	**1,264**	**1,264**	**1,264**	**1,264**	**1,264**	**1,264**	**1,264**	**1,264**	**1,264**	**1,264**
16 Cumulative Capacity w/ DSM	**21,900**	**21,959**	**22,054**	**22,756**	**22,852**	**23,891**	**23,898**	**23,963**	**24,051**	**25,250**	**25,321**	**26,503**	**26,556**	**26,238**	**26,188**
Reserves w/ DSM															
17 Generating Reserves	3,367	3,090	2,877	3,261	2,999	3,768	3,606	3,434	3,273	4,165	4,001	4,908	4,650	3,962	3,651
18 % Reserve Margin	**18.17%**	**16.38%**	**15.00%**	**16.73%**	**15.11%**	**18.73%**	**17.77%**	**16.73%**	**15.76%**	**19.75%**	**18.77%**	**22.73%**	**21.23%**	**17.79%**	**16.20%**

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

Winter Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2014 Annual Plan

	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29
Load Forecast														
1 Duke System Peak	17,784	18,175	18,556	18,934	19,246	19,485	19,771	20,092	20,478	20,829	21,180	21,520	21,933	22,243
2 Firm Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(100)	(145)	(192)	(262)	(317)	(379)	(449)	(523)	(595)	(671)	(740)	(799)	(850)	(896)
4 Adjusted Duke System Peak	**17,684**	**18,029**	**18,364**	**18,672**	**18,929**	**19,105**	**19,322**	**19,570**	**19,883**	**20,158**	**20,440**	**20,721**	**21,083**	**21,346**
Existing and Designated Resources														
5 Generating Capacity	21,227	21,087	21,132	21,877	21,812	21,822	21,828	21,828	21,828	21,828	21,828	21,828	21,828	21,828
6 Designated Additions / Uprates	232	45	745	0	10	6	0	0	0	0	0	0	0	0
7 Retirements / Derates	(372)	0	0	(65)	0	0	0	0	0	0	0	0	0	(1,161)
8 Cumulative Generating Capacity	**21,087**	**21,132**	**21,877**	**21,812**	**21,822**	**21,828**	**21,828**	**21,828**	**21,828**	**21,828**	**21,828**	**21,828**	**21,828**	**20,667**
Purchase Contracts														
9 Cumulative Purchase Contracts	**205**	**199**	**198**	**195**	**155**	**152**	**60**	**41**	**39**	**39**	**39**	**39**	**39**	**18**
Non-Compliance Renewable Purchases	29	24	22	19	18	18	18	18	16	15	15	15	15	5
Non-Renewables Purchases	175	175	175	175	137	134	42	24	24	24	24	24	24	14
Undesignated Future Resources														
10 Nuclear	0	0	0	0	0	0	0	0	0	1,117	0	1,117	0	0
11 Combined Cycle	0	0	0	0	0	907	0	0	0	0	0	0	0	0
12 Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0	0	872
Renewables														
13 Cumulative Renewables Capacity	121	132	130	117	160	262	297	328	366	401	424	444	458	475
14 Cumulative Production Capacity	**21,413**	**21,463**	**22,205**	**22,123**	**22,136**	**23,148**	**23,091**	**23,103**	**23,139**	**24,292**	**24,314**	**25,452**	**25,465**	**25,172**
Demand Side Management (DSM)														
15 Cumulative DSM Capacity	**570**	**577**	**588**	**594**	**597**	**601**	**601**	**601**	**601**	**601**	**601**	**601**	**601**	**601**
16 Cumulative Capacity w/ DSM	**21,983**	**22,040**	**22,792**	**22,718**	**22,733**	**23,748**	**23,692**	**23,704**	**23,740**	**24,892**	**24,915**	**26,053**	**26,066**	**25,773**
Reserves w/ DSM														
17 Generating Reserves	4,299	4,010	4,428	4,046	3,804	4,643	4,369	4,134	3,857	4,734	4,475	5,331	4,983	4,427
18 % Reserve Margin	**24.3%**	**22.2%**	**24.1%**	**21.7%**	**20.1%**	**24.3%**	**22.6%**	**21.1%**	**19.4%**	**23.5%**	**21.9%**	**25.7%**	**23.6%**	**20.7%**

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. This backstand is included in Line 1.

2. A 150 MW firm sale is included in 2014. The sale ends in 2014.

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

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

5. Existing generating capacity reflecting designated additions, planned uprates, retirements and derates as of April, 2014.

   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).

   Lee Combined Cycle is reflected in 2028 (670 MW). This is the DEC capacity net of 100 MW to be owned by NCEMC.

   Capacity Additions include Duke Energy Carolinas hydro units scheduled to be repaired and returned to service. The units are returned to service in the 2014-2020 timeframe and total 18 MW.

   Also included is a 105 MW capacity increase due to nuclear uprates at Catawba, McGuire, and Oconee. Timing of these uprates is shown from 2015-2017.

7. The 370 MW capacity retirement in summer 2015 represents the projected retirement date for Lee Steam Station.

   A planning assumption for coal retirements has been included in the 2014 IRP.

   Allen Steam Station (1127 MW) is assumed to retire in 2028.
   Nuclear Stations are assumed to retire at the end of their current license extension.

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

   No nuclear facilities are assumed to retire in the 15 year study period.

   The Hydro facilities for which Duke has submitted an application to FERC for license renewal are assumed to continue operation through the planning horizon.

   All retirement dates are subject to review on an ongoing basis.

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

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.

   Additional line items are shown under the total line item to show the amounts of renewable and traditional QF purchases. Renewables in these line items are not used for NC REPS compliance.

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.

    Addition of 1,117 MW Lee Nuclear Unit additions in 2024 and 2026.

11. New combined cycle 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 866 MW of combined cycle capacity in 2020.

12. New combustion turbine 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 792 MW of combustion turbine capacity in 2028.

13. Cumulative solar, biomass, hydro and wind resources to meet NC REPS compliance

    Also includes compliance resources for South Carolina (discussions in Chapter 5).

14. Sum of lines 8 through 13.

15. Cumulative Demand Response programs including load control and DSDR.

16. Sum of lines 14 and 15.

17. The difference between lines 4 and 16.

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

A tabular presentation of the Base Case resource plan represented in the above LCR table is shown below:

Table 8-D DEC Base Case

Duke Energy Carolinas Resource Plan [1] Base Case						
Year	**Resource**			**MW**		
2015	Lee 3 NG Conversion	Nuclear Uprates	Hydro Units Return to Service [2]	170	60	2
2016	-			-		
2017	Nuclear Uprates			45		
2018	Lee CC [3]			670		
2019	Hydro Units Return to Service [4]			10		
2020	New CC		Hydro Units Return to Service [4]	866		6
2021	-			-		
2022	-			-		
2023	-			-		
2024	New Nuclear			1117		
2025	-			-		
2026	New Nuclear			1117		
2027	-			-		
2028	New CT			792		
2029	-			-		

Notes: (1) Table includes both designated and undesignated capacity additions

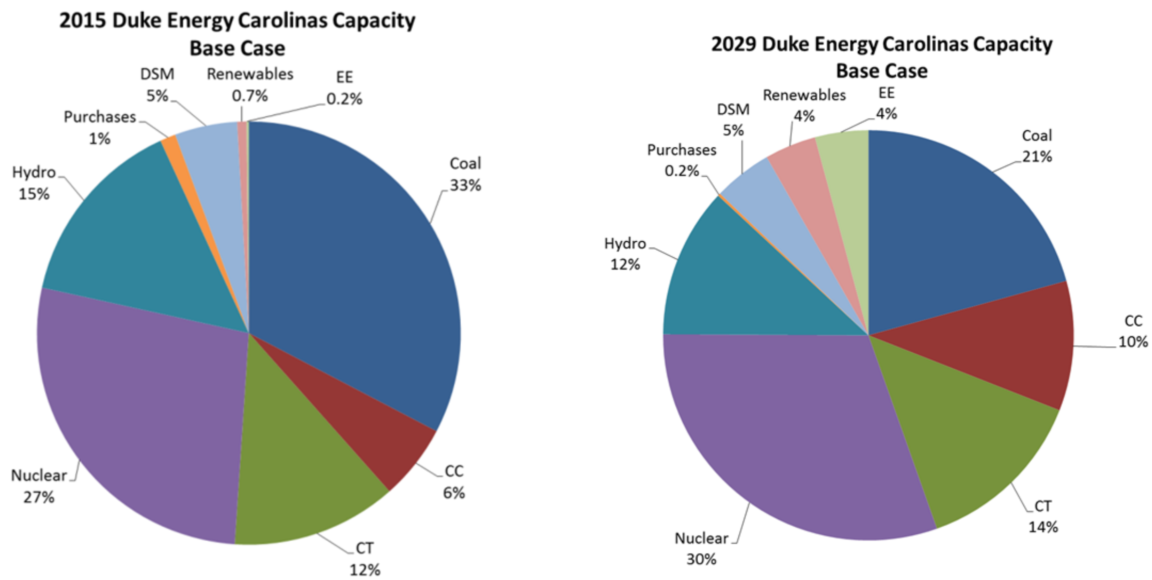
(2) Bryson City and Mission hydro units return to service

(3) Lee CC capacity is net of NCEMC ownership of 100 MW

(4) Rocky Creek Units currently offline for refurbishment; these are expected return to service dates

The following charts illustrate both the current and forecasted capacity by fuel type for the DEC system, as projected by the Base Case. As demonstrated in Chart 8-B, the capacity mix for the DEC system changes with the passage of time. In 2029, 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.

Chart 8-B 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 in Appendix A. As previously noted, the further out in time planned additions or retirements are within the 2014 IRP, the greater the opportunity for input assumptions to change. Thus, resource allocation decisions at the end of the planning horizon have a greater possibility for change as compared to those earlier in the planning horizon.

Joint Planning Case

A Joint Planning Case that begins to explore the potential for DEC and DEP to share firm capacity between the Companies was also developed. The focus of this case 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 or purchasing new capacity additions. This case does not address the specific implementation methods or issues required to implement shared capacity. Rather, this case 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.

[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 energy.

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

Table 8-E DEC and DEP Joint Planning Case

Duke Energy Carolinas and Duke Energy Progress Combined Base Cases [(1)]

Year	Resource		MW	
2015	-		-	
2016	-		-	
2017	-		-	
2018	-		-	
2019	-		-	
2020	New CC	New CC	866	866
2021	New CT		792	
2022	New CC		866	
2023	-		-	
2024	New Nuclear		1117	
2025	-		-	
2026	New Nuclear		1117	
2027	New CC		866	
2028	New CT		792	
2029	New CT		396	

Notes: (1) Table only includes undesignated capacity additions

Delays CC 1 year

Delays Need for CT & Reduces Total CT Need

Delays CC 1 year

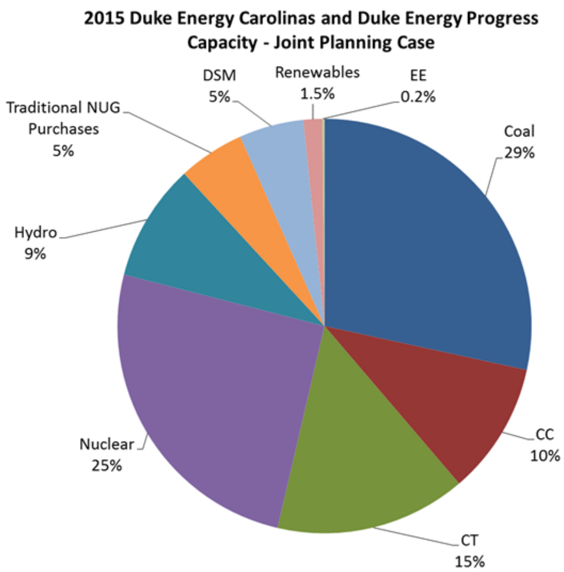
Duke Energy Carolinas and Duke Energy Progress Joint Planning Case

Year	Resource		MW	
2015	-		-	
2016	-		-	
2017	-		-	
2018	-		-	
2019	-		-	
2020	New CC		866	
2021	New CC		866	
2022	New CC		866	
2023	-		-	
2024	New Nuclear		659 / 458	
2025	-		-	
2026	New Nuclear		659 / 458	
2027	-		-	
2028	New CC	New CT	866	1188
2029	New CT		396	

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

Under a carbon constrained future, the collective output from nuclear generation is projected to remain at approximately half of all energy requirements for DEC and DEP collectively assuming the addition of the Lee Nuclear Station. Conversely, the output of coal-fired facilities is expected to be reduced by more than half while natural gas generation more than doubles in output over the planning horizon. Renewable and EE resources grow significantly from today's levels making meaningful contributions to the energy needs of the Carolinas. However, these resources do have limitations in their aggregate energy contributions due to physical limitations associated with intermittency, as well as economic limitations in light of expiring tax subsidies.

Chart 8-C <u>**CAPACITY CHARTS**</u>
(DEC and DEP Joint Planning Case)



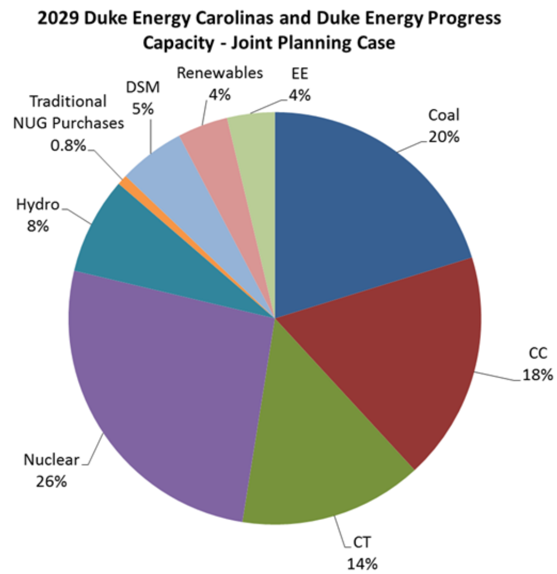
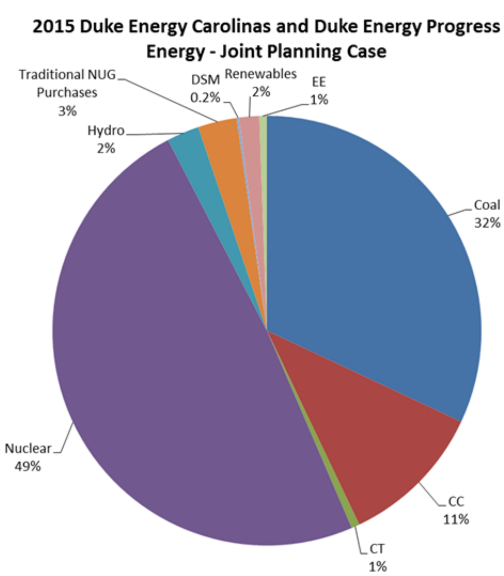
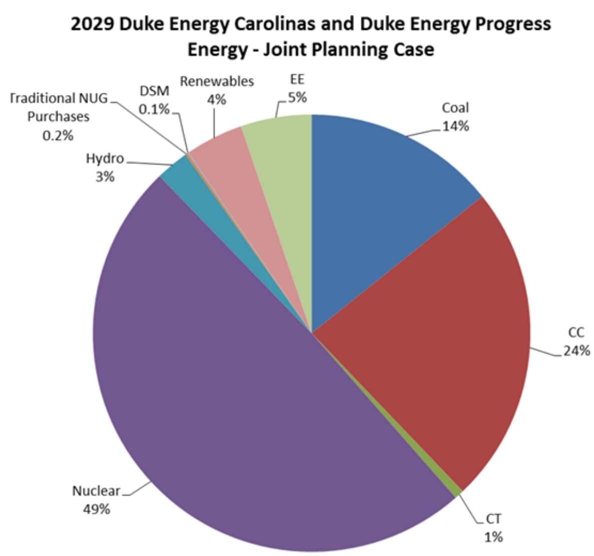


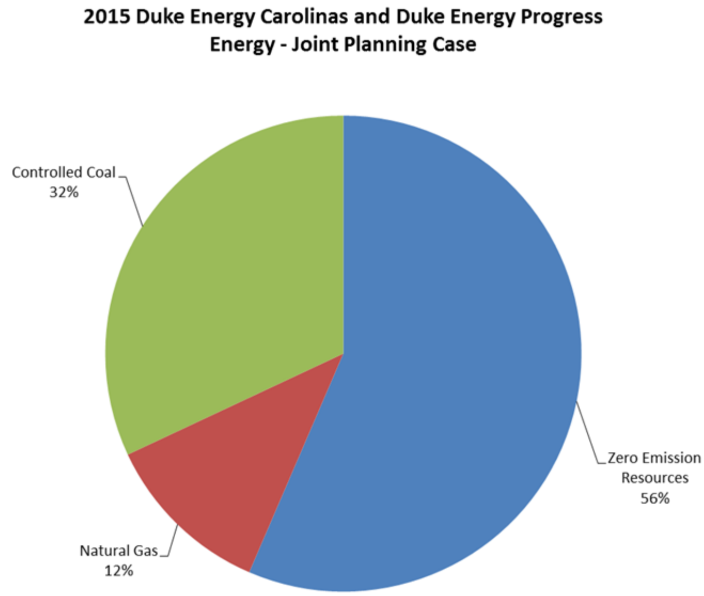
Chart 8-D <u>**ENERGY CHARTS**</u>
(DEC and DEP Joint Planning Case)

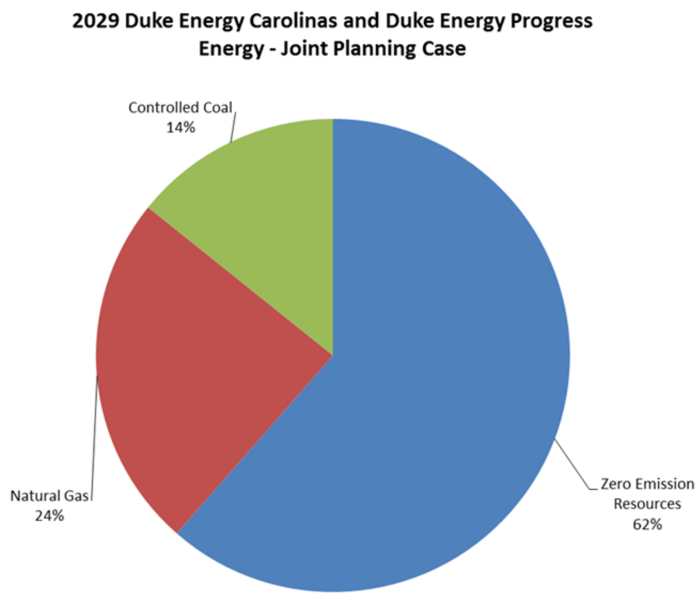




The following charts group the energy sources based upon the emissions impacts of the resources in the DEC and DEP Joint Planning Case. The Zero Emission category includes nuclear, hydro, renewables, EE and DSM resources. The Natural Gas category includes clean burning gas CCs and CTs. It must be noted that the remaining coal facilities are controlled with state-of-the-art environmental emission control technologies.

Chart 8-E DEC and DEP Energy by Emission Impact – Joint Planning Case





Note: Oil-fired CTs produce a negligible amount of energy and only at times of extreme peaks. This represents less than 1% of annual energy contribution.

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:

Continued Reliance on EE and DSM Resources:

The Company is committed to continuing to grow the amount of EE and DSM resources utilized to meet customer growth. The following are the ways in which DEC will increase these resources:

- Continue to execute the Company's EE and DSM plan, which includes a diverse portfolio of EE and DSM programs spanning the residential, commercial and industrial classes. 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 EE/DSM portfolio by: (1) adding new or expanding existing programs to include additional measures, (2) modifying programs modifications to account for changing market conditions and new measurement and verification (M&V) results and (3) considering other EE research and development pilots.

Continued Focus on Renewable Energy Resources:

DEC is committed to full compliance with NC REPS in North Carolina and is actively exploring incremental renewable resource additions contemplated under the recently passed South Carolina legislation. Due to Federal and State subsidies for solar developers, the Company is experiencing a substantial increase in solar QFs in the interconnection queue. With this level of interest in solar development, DEC continues to procure renewable purchase power resources, when economically viable, as part of its Compliance Plan. DEC is also pursuing the addition of new utility-owned solar on the DEC system.

DEC continues 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 Pursue New Nuclear

As part of the 2014 IRP, new nuclear resources continue to be supported in the resource plan in the 2024 and 2026 timeframe. As such, DEC remains on course to obtain the COL for the Lee Nuclear facility in 2016. The following is a summary of the activities relative to the COL for the Lee Nuclear facility.

On Dec. 23, 2013, the NRC issued the Final Environmental Impact Statement (FEIS) for Lee Nuclear, and on Jan. 2, 2014, the South Carolina Department of Health and Environmental Control (SC DHEC) issued the final Water Quality Certification[2]. With the National Pollutant Discharge Elimination System (NPDES)[2] permit, which was issued in July 2013, all of the major, required environmental permits and certifications required for the COL have been received. The NRC's COL licensing schedule targets the Advanced Final Safety Evaluation Report to be issued in May 2015, the Advisory Committee on Reactor Safeguards (ACRS) review of Advanced Final Safety Evaluation Report (SER) in September of 2015, the Final Safety Evaluation Report to be issued in December of 2015, and the mandatory hearing in April 2016 and, if this schedule is met, the COL is expected shortly thereafter.

Several final issues must be completed prior to NRC licensure of Lee Nuclear.

- 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 Duke Energy Carolinas to update the Lee Nuclear site-specific seismic analysis to incorporate the new Central and Eastern United States Seismic Source Characterization model[3]. Duke Energy Carolinas submitted the seismic hazard evaluation for the station that was required as a follow-up action from the Fukushima event. The seismic update for the nuclear island was submitted to the NRC in January 2014, and the update for buildings adjacent to the nuclear island was submitted in February 2014.

- Westinghouse in late 2013 indicated that modifications are being made to the passive emergency cooling system[4] of its AP1000 reactor design after an analysis showed that condensate flow would be lower than previously estimated. In February 2014 Duke Energy Florida[5] submitted an update to the Levy Nuclear Plant COL to address the modifications to the passive emergency cooling system. The NRC is advancing on its review of proposed changes to the design of the condensate return system of Westinghouse's AP1000 reactor, which it expects to complete by the end of 2014.

- On June 8, 2012, the District of Columbia Court of Appeals invalidated the NRC's most recent promulgation of the Waste Confidence rule[6]. In an August 7, 2012, adjudicatory decision, the Commission stated the NRC would not issue new licenses

[2] The Section 402 NPDES permit and the Section 401 Water Quality Certification are part of the Clean Water Act.
[3] This model was published as NUREG-2115 in January 2012.
[4] The condensate return system is part of the passive emergency cooling system that could be used to cool AP1000 units in certain types of incidents.
[5] The passive emergency cooling system issue is common to all AP1000 applicants and licensees; therefore, the NRC will review the changes for one AP1000 for application to all AP1000s. The lead review is of Duke Energy Florida's application for a COL for Levy Nuclear Plant.
[6] Note: the NRC has begun referring to the Waste Confidence rule as "Continued Storage of Spent Fuel" to better reflect its purpose.

or license renewals for reactors or independent spent fuel storage installations until the court's concerns had been appropriately addressed. On September 6, 2012, the NRC commissioners issued guidance to the NRC staff directing them to develop a generic Environmental Impact Statement (EIS) to support an updated Waste Confidence rule. The Commission provided a timeline of 24 months from the time of its order for the staff to finish the generic EIS and publish a final Waste Confidence rule. On September 13, 2013, the NRC issued a draft Waste Confidence rule and a draft generic EIS for public comment. In present form the proposed rule, if promulgated, would support issuing new and renewed licenses for power reactors and independent spent fuel storage installations. In January 2014, the NRC announced a delay in the schedule for completing the Waste Confidence rule. Due to an extended public comment period arising out of the Federal government shutdown in October 2013, the NRC now projects the final rule and associated EIS will be complete no later than October 3, 2014.

Addition of Clean Natural Gas Resources:

- Continue construction of the Lee combined cycle plant (Lee CC) at the Lee Steam Station site located in Anderson, SC. As demonstrated in recent IRP plans, a capacity need was identified in 2017/2018 to allow DEC to meet its customers' load demands. After evaluating multiple bids in a Request for Proposals (RFP) to address the 2017/2018 capacity need, the Company determined the most economic alternative to meet the need was to construct a new natural gas combined cycle facility at the Lee Steam Station site in Anderson County SC. The Company received a Certificate of Environmental Compatibility and Public Convenience and Necessity (CECPCN) in an order dated May 2, 2014, to move forward with the construction of the Lee CC.

- Complete the conversion of Lee Steam Station Unit 3 from coal to natural gas fuel. Lee Steam Station Unit 3 is reflected in the 2014 Duke Energy Carolinas IRP as a retired coal unit by April 2015 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.

Continued Focus on Environmental Compliance & Wholesale:

- Retire older coal generation. As of April 2014, approximately 1,300 MW of older coal generation has been retired and replaced with clean-burning natural gas, renewable energy resources or energy efficiency. By April 2015, Duke Energy Carolinas will have no remaining older, un-scrubbed coal units in operation.

- 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), the new ozone National Ambient Air Quality Standard (NAAQS) and EPA's Clean Power Plan proposal (Section 111d of Clean Air Act regulating CO_2 from existing power plants).

- Aggressively pursue compliance with NC legislation addressing coal ash management and ash pond remediation. Ensure timely compliance plans and their associated costs are contemplated within the planning process and future integrated resource plans.
- 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 2014 IRP is shown in Table 9-A below. 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, EE and DSM represent cumulative totals.

Table 9-A DEC Short-Term Action Plan

Duke Energy Carolinas Short-Term Action Plan							
			Compliance Renewable Resources (Cumulative Nameplate MW)				
Year	Retirements	Additions (1)	Wind (2)	Solar (2)	Biomass/Hydro (3)	EE	DSM (4)
2015	370 MW Lee 1-3 Coal	170 MW Lee NG Conv 60 MW Nuc	0	373	102	101	1072
2016			0	448	110	164	1095
2017		45 MW Nuc	0	472	106	230	1142
2018		670 MW Lee CC (5)	0	497	92	297	1180
2019		10 MW Hydro Units (6) Return to Service	0	621	128	366	1213

Notes:
(1) Includes 105 MW of nuclear uprates
(2) Capacity is shown in nameplate ratings. For planning purposes, wind presents a 13% contribution to peak and solar has a 46% contribution to peak.
(3) Biomass includes swine and poultry contracts.
(4) Includes impacts of grid modernization.
(5) 670 MW is net of NCEMC portion of Lee CC
(6) Rocky Creek Hydro units are currently offline for refurbishment; this is expected return to service date

DEC Request for Proposal (RFP) Activity

Supply-Side

The CECPCN for the construction of the Lee CC facility was granted on May 2, 2014 following an extensive RFP process seeking dispatchable, non-peaking capacity. The air permit required for construction of the facility was received on February 19, 2014. Subsequent to permit approvals, final evaluations were completed for gas turbine, steam turbine, and heat recovery steam generator supply contracts, as well as the project engineering, procurement and construction (EPC) contract. These four contracts were awarded between June and August of 2014. Mobilization to the site and construction start is expected in the second quarter of 2015 in support of a November 1, 2017 commercial operation date.

Renewable Energy

A Solar RFP was released on February 13, 2014, to solicit for up to 300 MW of solar PV facilities that would provide power & associated renewable energy certificates within the DEC and DEP service territories. Executed contracts in response to this RFP will advance Duke Energy's goal of encouraging new opportunities for development, diversifying the electric supply mix, and complying with NC REPS.

The RFP interest was in PPAs and turnkey asset purchase proposals larger than 5.0 MW_{AC} with a preference for turnkey constructed projects larger than 20 MW_{AC}. Respondents to the RFP were allowed to submit up to a total of 5 proposals for turnkey or PPA projects that will be directly connected to the DEC or DEP transmission or distribution system. Projects must be in-service and capable of delivering full rated output by December 31, 2015. PPA contract durations could not exceed a 15-year term.

Following the close of the RFP on March 28, 2014, projects totaling 817 MW_{AC} were proposed from 23 different project sites. Proposal responses were submitted by 10 different counterparties. Projects proposed for DEC were comprised of 3 asset purchase proposals and 1 PPA proposal. Projects proposed for DEP were comprised of 13 asset purchase proposals and 6 PPA proposals.

Respondents were notified in April 2014 of their proposal status and if they had been shortlisted.

The Due Diligence process was then conducted on the shortlisted asset purchase proposals by internal technical experts as well as by Luminate, a management consultant, that serves the power, energy and renewable markets. Following the completion of the asset purchase Due Diligence process, the next steps are to occur by October 1, 2014. Those steps are to negotiate definitive contract agreements, seek appropriate Duke Energy executive approval, seek NCUC – Certificate of

Public Convenience and Necessity (CPCN) transfer/assignment approval request, and procure long lead time items.

Shortlisted PPA proposals are currently in varying stages of contract execution.

APPENDIX A: QUANTITATIVE ANALYSIS

This appendix provides an overview of the Company's quantitative analysis of the resource options available to meet customers' future energy needs. Sensitivities on major inputs resulted in multiple portfolios that were then evaluated in both a future where carbon emissions are constrained using a proxy CO_2 price forecast and a future where there are no constraints on carbon emissions and no explicit price on CO_2. These portfolios were analyzed using a least cost analysis to determine the Base Case for the 2014 IRP. The selection of this plan takes into account the cost to customers, resource diversity and reliability and the long-term carbon intensity of the system.

The future resource needs were optimized for DEC and DEP independently. However, an additional case representative of jointly planning future capacity on a DEC/DEP combined system basis using the Base Case assumptions was also analyzed to demonstrate potential customer savings, if this option was available in the future.

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 peak demand and energy load forecast – identified future customer aggregate demands to determine system peak demands and developed the corresponding energy load shape. Two forecasts were developed (with and without a future CO_2 price structure) that illustrate the impact carbon emissions constraints would have on energy demand.
- 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 in the future. The following assumptions impacted the 2014 resource plan:

- With the impacts of constrained carbon emissions considered, the growth in summer customer peak demand after the impact of energy efficiency averaged 1.4% from 2015 through 2029. The forecasted compound annual growth rate for energy load is 1.0% after the impacts of energy efficiency programs are included. If carbon emissions are not constrained, the average growth in summer peak demand increases to 1.5% annually and the annual energy growth rate increases to 1.3%. In all cases, these growth rates are inclusive of the impacts of projected energy efficiency programs.
- Retirement of 370 MW at Lee Steam Station by June 2015
- Conversion of 170 MW of Lee Unit 3 to natural gas in April 2015
- Expected nuclear uprates of 105 MW by 2017
- A projected retirement of 1,127 MW at the Allen Steam Station in 2028
- 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 traditional and non-traditional supply-side options to meet customer energy and capacity needs. The Company developed EE and DSM projections based on existing EE/DSM program experience, the most recent market potential study, input from its EE/DSM collaborative and cost-effectiveness screening for use in the IRP. Supply-side options reflect a diverse mix of technologies and fuel sources (gas, 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 the capacity size options and operational capabilities of each technology, with the most cost-effective options of each being selected for inclusion in the portfolio analysis phase. An overview of resources screened on technical basis and a levelized economic basis is discussed 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 – 688 MW – 2 x 1 Combined Cycle (Inlet Chiller and Duct Fired)
- Baseload – 866 MW – 2 x 1 Advanced Combined Cycle (Inlet Chiller and Duct Fired)
- Peaking/Intermediate – 396 MW – 2 x 7FA.05 CTs
    - (Based upon the cost to construct 4 units, available for brownfield sites only)
- Peaking/Intermediate – 792 MW – 4 x 7FA.05 CTs
- Renewable – 150 MW – On-shore Wind
- Renewable – 25 MW – Solar PV

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

EE and DSM programs continue to be an important part of Duke Energy Carolinas' system mix. The Company considered both EE and DSM 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 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. The impacts of this goal were incorporated in two of the five portfolios evaluated. The program costs used for this analysis leveraged the Company's internal projections for the first five years and in the longer term, utilized the 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 the simulation modeling software, *System Optimizer* (SO). SO identified five portfolios that encompass the impact of the range of input sensitivities evaluated. An overview of the base planning assumptions and sensitivities considered is outlined below:

- Impact of potential carbon constraints
  - All sensitivities were evaluated under scenarios including the impacts where carbon emissions are constrained using a proxy CO_2 price forecast (With CO_2 Scenario) and assuming that there is not an explicit price on CO_2 (No CO_2 Scenario).
    - In the With CO_2 Scenario, the carbon price is assumed to initially be $17 /ton in 2020 and to increase linearly to $36/ton by 2029
    - Additionally, a high CO_2 sensitivity was also conducted using the carbon price assumed to initially be $20/ton in 2020 and increase linearly to $50/ton by 2029.
- Retirements
  - Coal assets – For the purpose of this IRP, the depreciation book life was used as a placeholder for future retirement dates for coal assets. Based on this assumption, Allen Steam Station was retired in 2028.
  - Nuclear assets – Oconee Nuclear Station's current operating license has been extended to 60 years and expires in 2033. To date, no nuclear units in the United States have received a license extension beyond 60 years. For the purpose of this IRP, the Oconee Station is assumed to be retired in 2033.
- Coal and natural gas fuel prices
  - Sensitivities of +/– 15% were performed for coal and gas prices, individually.
    - Short-term pricing: Based on market observations
    - Long-term pricing: Based on the Company's fundamental fuel price projections. Separate fuel prices were developed for the With CO_2 Scenario and the No CO_2 Scenario.
- Capital Cost Sensitivities
  - Nuclear – Varied capital cost by +/- 10%
  - CC/CT – Varied capital cost by +/- 20 %
  - Renewables – Resources to comply with NC REPS and a placeholder renewable energy requirement for South Carolina were input as existing resources. To determine if additional renewable resources would be selected, a capital cost

sensitivity was performed for solar in both the With CO_2 and No CO_2 Scenarios. Below is an overview of the sensitivities performed:

- Solar
    - Base – Solar facility cost estimates plus a 10% Federal Investment Tax Credit (ITC)
    - Base inclusive of the Federal ITC with an additional 25% reduction in capital cost (approximately a 35% total reduction)
    - Base inclusive of the Federal ITC with an additional 55% reduction in capital cost (approximately a 65% total reduction)
- Wind
    - Cost sensitivities were not performed for wind due to the physical limitations on the amount that could be reasonably achieved in the Carolinas.
    - The SO model was allowed to select additional wind resources at the current estimated price.

- Nuclear Selection – Three different options were evaluated with regards to the selection of nuclear.
    - ➢ Allowed the SO model to select four nuclear units for the combined DEC/DEP system. The Company restricted placement of these units to three in DEC territory, two of which would represent Lee Nuclear Station with an additional generic unit in DEC, and one generic unit in DEP.
    - ➢ Allowed SO to select two nuclear units. These units represent Lee Nuclear Station in DEC.
    - ➢ Nuclear units are not a resource option.
- EE and Renewables – Two different options were evaluated with regards to the amount of EE and Renewables.
    - ➢ Base EE and Compliance Renewables
        - Base EE corresponds to the Company's current projections for achievable cost-effective EE program acceptance.

- Compliance renewables corresponds to the renewable resources needed to meet full compliance with NC REPS and a placeholder for future compliance requirements in South Carolina.

- High EE and High Renewables

  - Evaluated to assess the impact of additional EE and renewables on the expansion plan.

  - Aspirational EE – Established as part of the Duke Energy-Progress Energy Merger Settlement Agreement. The cumulative EE achievements since 2009 are counted toward the cumulative settlement agreement impacts. By 2029, this accounts for a 11% reduction in total load.

  - High Renewables – Represented 10% of gross MWh met with renewables incorporating the existing NC and SC renewable planning assumptions. The incremental amount was phased in from 2020 to 2030.

- High and Low Load – Sensitivities were performed assuming changes in load of +/- 5%.

Results

A review of the results from the sensitivity analysis yielded some common themes.

Initial Resource Needs - The first resource need after the Lee Combined Cycle Station with base EE and renewable assumptions was in 2020. Combined cycle generation was selected optimally for the With CO_2 Scenario and associated sensitivities. Combined cycle was also selected in the No CO_2 Scenario if gas prices were lower or if coal prices were higher.

New Nuclear Selection – In the With CO_2 Scenario, Lee Nuclear was selected in the 2024 to 2030 timeframe and two generic units were selected in the 2035 timeframe, one in DEC and one in DEP. New nuclear was not selected in the No CO_2 Scenario or in any of the sensitivities associated with this scenario.

Renewable Generation – No additional wind or solar generation in excess of the base assumptions was selected unless the capital cost was lower or incentivized over the 10% assumed in the Base Case. When the capital cost of solar was reduced by 35%, no additional solar was selected in the No CO_2 Scenario. However, additional solar was selected in the 2030 timeframe in the With CO_2 Scenario. When the solar capital cost was lowered by 65%, additional solar was selected in the No CO_2 Scenario in the 2020 to 2025 timeframe. With the 65% reduction in solar capital cost, additional solar was selected throughout the planning horizon in the With CO_2 Scenario.

Gas Firing Technology Options – In general, combustion turbines were selected in lieu of combined cycle generation in the No CO_2 Scenario. However, if gas prices are lower or if coal prices are higher, additional combined cycle generation is selected instead of CTs.

High EE and Renewables – The first resource need, other than the additional renewable resources included in this scenario, remains in 2023 in the No CO_2 Scenario and in 2026 in the With CO_2 Scenario. It was also observed that after a significant amount of solar was implemented, the need for new resource additions was driven by the winter reserve margin. In this instance, the winter reserve margin dipped below the acceptable minimum planning reserve margin. This phenomenon occurred because solar contributed to reducing the summer peak need but did not reduce the peak need in the winter.

Portfolio Development

Using insights gleaned from the sensitivity analysis, five portfolios were developed. The primary purpose of these portfolios was to assess the value of new nuclear generation considering the potential for additional EE and renewable generation.

Portfolio 1 (No Nuclear, Base EE/Renewables)
This portfolio was developed to simulate a future where nuclear is not available as a resource option going forward with base EE and renewable assumptions.

Portfolio 2 (Lee Nuclear, Base EE/Renewables)
This portfolio was developed to simulate a future where Lee Nuclear Station is the only new nuclear generation installed in the 2024 to 2034 timeframe with base EE and renewable assumptions.

Portfolio 3 (Lee Nuclear + 2 New Nuclear (1 DEC/1 DEP), Base EE/Renewables)
This portfolio was developed to simulate a future where Lee Nuclear Station is constructed on the DEC system plus one additional generic nuclear unit is installed on each of the DEP and DEC systems during the 2024 to 2034 timeframe with base EE and renewable assumptions.

Portfolio 4 (No Nuclear, High EE/Renewables)
This portfolio was developed to simulate a future where nuclear is not available as a resource option going forward with the assumption of aspirational EE and high renewables.

Portfolio 5 (Lee Nuclear, High EE/Renewables)
This portfolio was developed to simulate a future where Lee Nuclear Station is the only new nuclear generation installed during the 2024 to 2034 timeframe with the assumption of aspirational EE and high renewables.

An overview of the resource needs of each portfolio are shown in Table A-1 below. The amount of renewables in each portfolio is summarized in Table A-2.

Table A-1 Duke Energy Carolinas Portfolio Summary Plans

Duke Energy Carolinas - Portfolios										
	P1		P2		P3		P4		P5	
Year	Tech	MW	Tech	MW	Tech	MW	Tech	MW	Tech	MW
2020	CC	866	CC	866	CC	866		-		-
2021		-		-		-		-		-
2022		-		-		-		-		-
2023	CC	866		-		-		-		-
2024		-	NUC	1,117	NUC	1,117		-	NUC	1,117
2025		-		-		-		-		-
2026		-	NUC	1,117	NUC	1,117	CC	866	NUC	1,117
2027	CC	866		-		-	CT	396		-
2028	CC	1,732	CT	396	CT	792	CC	866		-
2029		-	CC	866		-	CT	396	CT	396
2030		-		-		-		-	CC	866
2031	CT	396	CC	866	CC	866	CC	866		-
2032	CC	866		-	CC	792		-	CT	198
2033	CC	2,598	CC	2,598	CC	1,732	CC	2,598	CC	2,598
		-	CT	594	NUC	1,117	CT	198		-
2034	CT	198		-		-	CC	866	CC	866
		-		-		-		-	CT	198
Total										
	CC	7794	CC	5196	CC	4256	CC	6062	CC	4330
	CT	594	CT	990	CT	792	CT	990	CT	792
	NUC	0	NUC	2234	NUC	3351	NUC	0	NUC	2234
Total		8388		8420		8399		7052		7356

Table A-2 DEC Renewable Summary

DEC Renewables									
Portfolios 1,2 & 3					Portfolios 4&5				
MW Nameplate					MW Nameplate				
	Wind	Solar	Biomass/ Hydro	Total		Wind	Solar	Biomass/ Hydro	Total
2015	0	480	126	607	2015	0	480	126	607
2016	0	554	128	683	2016	0	554	128	683
2017	0	572	124	696	2017	0	572	124	696
2018	0	597	106	703	2018	0	597	106	703
2019	0	719	141	860	2019	0	719	141	860
2020	150	869	171	1190	2020	178	1183	171	1532
2021	150	1009	200	1359	2021	205	1637	200	2042
2022	150	1139	224	1512	2022	233	2081	224	2538
2023	150	1265	253	1668	2023	261	2521	253	3035
2024	150	1381	283	1814	2024	289	2951	283	3523
2025	150	1498	300	1947	2025	316	3382	300	3998
2026	150	1605	315	2070	2026	344	3804	315	4462
2027	150	1702	324	2175	2027	372	4215	324	4910
2028	150	1754	327	2231	2028	399	4581	327	5307
2029	150	1681	324	2155	2029	427	4823	324	5574

4. Perform Portfolio Analysis

The five portfolios identified in the screening analysis were evaluated in more detail with an hourly production cost model (PROSYM) under the With CO_2 and No CO_2 Scenarios. High and low fuel and high CO_2 price sensitivities were also performed to ensure the robustness of each portfolio.

Table A-3 below summarizes the revenue requirements of each portfolio compared to Portfolio 3 over the range of scenarios and sensitivities[7].

Table A-3   Delta PVRR for All Portfolios

Delta Costs for DEC Portfolios							
Delta PVRR 2014 - 2064 ($Billions) Compared to Portfolio 3							
	With CO2 Scenario				No CO2 Scenario		
	Base	High Fuel	Low Fuel	High CO2	Base	High Fuel	Low Fuel
Portfolio 1	$ 0.2	$ 2.0	$ (1.6)	$ 2.8	$ (6.6)	$ (4.8)	$ (8.3)
Portfolio 2	$ 0.5	$ 0.9	$ 0.1	$ 1.2	$ (1.7)	$ (1.3)	$ (2.1)
Portfolio 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Portfolio 4	$ 5.3	$ 5.9	$ 4.6	$ 6.8	$ 1.6	$ 2.3	$ 0.9
Portfolio 5	$ 5.7	$ 5.1	$ 6.4	$ 5.0	$ 7.2	$ 6.6	$ 7.7
Note: Positive values indicate Portfolio 3 is lower cost; Negative values indicate Portfolio 3 is higher cost							

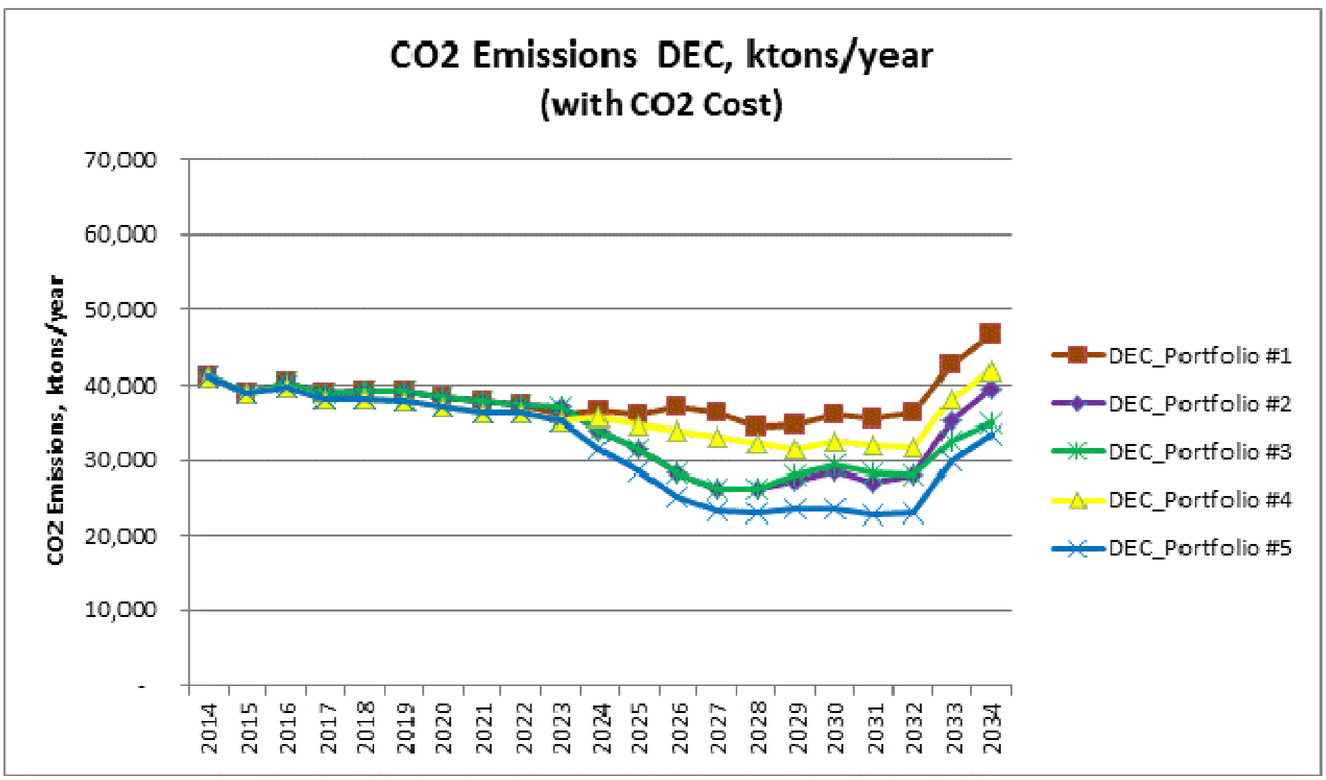
[7] PVRR includes the cost of integrating solar as represented in the Duke Energy Photovoltaic Integration Study published by Pacific Northwest National Lab in March 2014.

In the With CO_2 Scenario, Portfolio 3 resulted in the lowest PVRR in the Base Case and in the High Fuel and High CO_2 sensitivities. Portfolios 1, 2, and 3 were all very close in overall PVRR. It was also noted that without the addition of nuclear resources in Portfolio 1, system carbon emissions begin to rise by the end of the planning horizon. The costs of Portfolios 4 and 5 were negatively impacted by expanding the amount of renewable resources beyond the NC REPS requirements and energy efficiency above the achievable potential.

In the No CO_2 Scenario, the PVRR of Portfolio 1is lower than the PVRRs of Portfolios 2 and 3 by approximately $5-6.5 billion dollars. In the High Fuel sensitivity, that difference is reduced to $3.5-4.5 billion.

Without the addition of new nuclear to replace retiring nuclear units, the CO_2 emissions increase significantly in the 2030 to 2035 timeframe. Figure A–1 illustrates this point by comparing the total system CO_2 emissions of the Portfolios through 2034. To this point, when the Oconee Nuclear Station is retired in 2033 in this IRP, all Portfolios except for Portfolio 5 have significantly higher CO_2 emissions than the Base Case in 2034. While Portfolio 5 has roughly the same CO_2 footprint as the Base Case in 2034, Portfolio 5 is achieved with significantly higher costs.

Figure A-1 DEC Carbon Intensity Summary



Conclusions

For planning purposes, Duke Energy considers the potential impact of a future where carbon emissions are constrained as the base plan. Portfolios 1 and 2 are competitive from a revenue requirement basis in the With CO_2 Scenario, however its carbon footprint would not be sustainable in the long term if retired nuclear is not replaced with new nuclear generation. By 2034, approximately 3,300 MW of existing nuclear generation will be retired in DEC and DEP unless their licenses can be extended. To date, no nuclear units in the United States have received a license extension beyond sixty years. Portfolio 3 adds Lee Nuclear Station in the 2024-2026 timeframe and one generic nuclear unit in 2032 (DEP) and one in 2033 (DEC) totaling 4,470 MW. This results in 1,100 MW of additional nuclear as compared to the current DEC and DEP systems today.

Duke Energy's current modeling practice uses a proxy CO_2 price forecast to simulate compliance in a future where carbon emissions are constrained; however, EPA has recently proposed a regulation (the Clean Power Plan) that would limit the rate at which each state could emit CO_2. There is a great deal of uncertainty with regards to how the proposed EPA Clean Power Plan rule will be finalized and implemented. However, as currently proposed, the plan calls for an average reduction of the statewide CO_2 emissions rate (tons/MWh) from 2020 to 2029 and a further lowered target in 2030 and beyond. As shown in Figure A–1 Lee Nuclear Station coming on line in the 2024-2026 timeframe provides significant CO_2 reduction and would aid in meeting the average reduction target. For these reasons, Portfolio 3 is considered the Base Case for the 2014 IRP.

Value of Joint Planning

To demonstrate the value of sharing capacity with DEP, a Joint Planning Case was developed to examine the impact of joint capacity planning on the resource plans. The impacts were determined by comparing how the combined Base Cases 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 evaluation was performed comparing the optimally selected Portfolio 3 for DEC and DEP to a combined Joint Planning Case in which existing and future capacity resources could be shared between DEC and DEP to meet the 14.5% minimum planning reserve margin. In this Joint Planning Case, sharing the Lee Nuclear Station on a load ratio basis with DEP was the most economic selection. Table A-4 shows the total incremental natural gas and nuclear capacity needed to meet the projected minimum planning reserve margin in the 2015 to 2029 timeframe for both DEC and DEP, if separately planned. The sum total of the two combined resource requirements is then compared to the amount of resources needed if DEC and DEP were able to jointly plan for capacity.

Table A-4 Comparison of Base Case Portfolio to Joint Planning Case

DEC Base Case (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Gas Units						866								792	
Nuclear										1117		1117			
DEP Base Case (MW)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Gas Units						866	792	866					866		396
Nuclear															
DEC & DEP Combined Base Case (MW)	0	0	0	0	0	1732	792	866	0	1117	0	1117	866	792	396
Combined Base Case Reserve Margin	19.4%	17.9%	16.8%	16.9%	15.4%	18.1%	17.5%	17.9%	16.8%	18.5%	17.9%	19.6%	19.9%	17.1%	16.4%
Joint Planning Case (MW)	0	0	0	0	0	866	866	866	0	1117	0	1117	0	2054	396
Joint Planning Case Reserve Margin	19.4%	17.9%	16.8%	16.9%	15.4%	15.5%	15.2%	15.6%	14.5%	16.3%	15.7%	17.5%	15.4%	16.1%	15.4%

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 2015 to 2029 planning horizon. Consequently, the Joint Planning Case 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 Case, which averaged 17.7% and 16.2%, respectively, from the first resource need in 2020 through 2029. The lower reserve margin in the Joint Planning Case indicates that DEC and DEP more efficiently and economically meet capacity needs when planning for capacity jointly. This is reflected in a total PVRR savings of $0.3 billion for the Joint Planning Case as compared to the Base Case through 2029.

B. Quantitative Analysis Summary

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

1. The first undesignated resource need is in 2020 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 capacity with DEP provides customer savings by allowing for the deferral of new generation resources over the 2015 through 2029 planning horizon.

3. New nuclear generation is selected as an economic resource in a carbon-constrained future as identified in Portfolio 3. In the 15-year planning horizon, the addition of the Lee Nuclear Station in the 2024 to 2026 timeframe and two additional generic nuclear units, one in DEC and the other in DEP, were selected in the 15 to 20 year planning horizon.

Portfolio 3 supports 100% ownership of Lee Nuclear Station by DEC. However, the Company continues to consider the benefits of regional nuclear generation. 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. The benefits of co-ownership of the Lee Nuclear Station with DEP were also illustrated with the ability to jointly plan as represented in the Joint Planning Case.

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 2013, Duke Energy Carolinas' nuclear and coal-fired generating units met the vast majority of customer needs by providing 60% and 30%, 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 and South Carolina 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, 2014

Coal						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Allen	1	167	162	Belmont, NC	Coal	Intermediate
Allen	2	167	162	Belmont, NC	Coal	Intermediate
Allen	3	270	261	Belmont, NC	Coal	Intermediate
Allen	4	282	276	Belmont, NC	Coal	Intermediate
Allen	5	275	266	Belmont, NC	Coal	Intermediate
Belews Creek	1	1135	1110	Belews Creek, NC	Coal	Base
Belews Creek	2	1135	1110	Belews Creek, NC	Coal	Base
Cliffside	5	556	552	Cliffside, NC	Coal	Base
Cliffside	6	844	825	Cliffside, NC	Coal	Base
Lee	1	100	100	Pelzer, SC	Coal	Peaking
Lee	2	102	100	Pelzer, SC	Coal	Peaking
Lee	3	170	170	Pelzer, SC	Coal	Peaking
Marshall	1	380	380	Terrell, NC	Coal	Intermediate
Marshall	2	380	380	Terrell, NC	Coal	Intermediate
Marshall	3	658	658	Terrell, NC	Coal	Base
Marshall	4	660	660	Terrell, NC	Coal	Base
Total NC		6,909	6,802			
Total SC		372	370			
Total Coal		7,281	7,172			

Combustion Turbines						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Lee	7C	41	41	Pelzer, SC	Natural Gas/Oil-Fired	Peaking
Lee	8C	41	41	Pelzer, SC	Natural Gas/Oil-Fired	Peaking
Lincoln	1	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	2	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	3	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	4	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	5	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	6	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	7	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	8	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	9	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	10	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	11	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	12	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	13	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	14	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	15	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	16	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Mill Creek	1	92.4	74.42	Blacksburg, SC	Natural Gas/Oil-Fired	Peaking
Mill Creek	2	92.4	74.42	Blacksburg, SC	Natural Gas/Oil-Fired	Peaking
Mill Creek	3	92.4	74.42	Blacksburg, SC	Natural Gas/Oil-Fired	Peaking
Mill Creek	4	92.4	74.42	Blacksburg, SC	Natural Gas/Oil-Fired	Peaking
Mill Creek	5	92.4	74.42	Blacksburg, SC	Natural Gas/Oil-Fired	Peaking
Mill Creek	6	92.4	74.42	Blacksburg, SC	Natural Gas/Oil-Fired	Peaking
Mill Creek	7	92.4	74.42	Blacksburg, SC	Natural Gas/Oil-Fired	Peaking
Mill Creek	8	92.4	74.42	Blacksburg, SC	Natural Gas/Oil-Fired	Peaking
Rockingham	1	179	165	Rockingham, NC	Natural Gas/Oil-Fired	Peaking
Rockingham	2	179	165	Rockingham, NC	Natural Gas/Oil-Fired	Peaking
Rockingham	3	179	165	Rockingham, NC	Natural Gas/Oil-Fired	Peaking
Rockingham	4	179	165	Rockingham, NC	Natural Gas/Oil-Fired	Peaking
Rockingham	5	179	165	Rockingham, NC	Natural Gas/Oil-Fired	Peaking
Total NC		2,383	2,092.2			
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	176	161	Salisbury, NC	Natural Gas	Base
Buck	CT12	173	161	Salisbury, NC	Natural Gas	Base
Buck	ST10	314	309	Salisbury, NC	Natural Gas	Base
Buck CTCC		663	631			
Dan River	CT8	175	161	Eden, NC	Natural Gas	Base
Dan River	CT9	176	161	Eden, NC	Natural Gas	Base
Dan River	ST7	316	315	Eden, NC	Natural Gas	Base
Dan River CTCC		667	637			
Total CTCC		1,330	1,268			

Pumped Storage						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Jocassee	1	195	195	Salem, SC	Pumped Storage	Peaking
Jocassee	2	195	195	Salem, SC	Pumped Storage	Peaking
Jocassee	3	195	195	Salem, SC	Pumped Storage	Peaking
Jocassee	4	195	195	Salem, SC	Pumped Storage	Peaking
Bad Creek	1	340	340	Salem, SC	Pumped Storage	Peaking
Bad Creek	2	340	340	Salem, SC	Pumped Storage	Peaking
Bad Creek	3	340	340	Salem, SC	Pumped Storage	Peaking
Bad Creek	4	340	340	Salem, SC	Pumped Storage	Peaking
Total Pumped Storage		2,140	2,140			

Hydro						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
99 Islands	1	2.4	2.4	Blacksburg, SC	Hydro	Peaking
99 Islands	2	2.4	2.4	Blacksburg, SC	Hydro	Peaking
99 Islands	3	2.4	2.4	Blacksburg, SC	Hydro	Peaking
99 Islands	4	2.4	2.4	Blacksburg, SC	Hydro	Peaking
99 Islands	5	0	0	Blacksburg, SC	Hydro	Peaking
99 Islands	6	0	0	Blacksburg, SC	Hydro	Peaking
Bear Creek	1	9.45	9.45	Tuckasegee, NC	Hydro	Peaking
Bridgewater	1	15	15	Morganton, NC	Hydro	Peaking
Bridgewater	2	15	15	Morganton, NC	Hydro	Peaking
Bridgewater	3	1.5	1.5	Morganton, NC	Hydro	Peaking
Bryson City	1	0.48	0.48	Whittier, NC	Hydro	Peaking
Bryson City	2	0	0	Whittier, NC	Hydro	Peaking
Cedar Cliff	1	6.4	6.4	Tuckasegee, NC	Hydro	Peaking
Cedar Cliff	2	0.4	0.4	Tuckasegee, NC	Hydro	Peaking
Cedar Creek	1	15	15	Great Falls, SC	Hydro	Peaking
Cedar Creek	2	15	15	Great Falls, SC	Hydro	Peaking
Cedar Creek	3	15	15	Great Falls, SC	Hydro	Peaking
Cowans Ford	1	81.3	81.3	Stanley, NC	Hydro	Peaking
Cowans Ford	2	81.3	81.3	Stanley, NC	Hydro	Peaking
Cowans Ford	3	81.3	81.3	Stanley, NC	Hydro	Peaking
Cowans Ford	4	81.3	81.3	Stanley, NC	Hydro	Peaking
Dearborn	1	14	14	Great Falls, SC	Hydro	Peaking
Dearborn	2	14	14	Great Falls, SC	Hydro	Peaking
Dearborn	3	14	14	Great Falls, SC	Hydro	Peaking
Fishing Creek	1	11	11	Great Falls, SC	Hydro	Peaking
Fishing Creek	2	9.5	9.5	Great Falls, SC	Hydro	Peaking
Fishing Creek	3	9.5	9.5	Great Falls, SC	Hydro	Peaking
Fishing Creek	4	11	11	Great Falls, SC	Hydro	Peaking
Fishing Creek	5	8	8	Great Falls, SC	Hydro	Peaking
Franklin	1	0.5	0.5	Franklin, NC	Hydro	Peaking
Franklin	2	0.5	0.5	Franklin, NC	Hydro	Peaking
Gaston Shoals	3	0	0	Blacksburg, SC	Hydro	Peaking
Gaston Shoals	4	1	1	Blacksburg, SC	Hydro	Peaking
Gaston Shoals	5	1	1	Blacksburg, SC	Hydro	Peaking
Gaston Shoals	6	0	0	Blacksburg, SC	Hydro	Peaking

Hydro cont.						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Great Falls	1	3	3	Great Falls, SC	Hydro	Peaking
Great Falls	2	3	3	Great Falls, SC	Hydro	Peaking
Great Falls	3	0	0	Great Falls, SC	Hydro	Peaking
Great Falls	4	0	0	Great Falls, SC	Hydro	Peaking
Great Falls	5	3	3	Great Falls, SC	Hydro	Peaking
Great Falls	6	3	3	Great Falls, SC	Hydro	Peaking
Great Falls	7	0	0	Great Falls, SC	Hydro	Peaking
Great Falls	8	0	0	Great Falls, SC	Hydro	Peaking
Keowee	1	76	76	Seneca, SC	Hydro	Peaking
Keowee	2	76	76	Seneca, SC	Hydro	Peaking
Lookout Shoals	1	9.3	9.3	Statesville, NC	Hydro	Peaking
Lookout Shoals	2	9.3	9.3	Statesville, NC	Hydro	Peaking
Lookout Shoals	3	9.3	9.3	Statesville, NC	Hydro	Peaking
Mission	1	0.6	0.6	Murphy, NC	Hydro	Peaking
Mission	2	0.6	0.6	Murphy, NC	Hydro	Peaking
Mission	3	0.6	0.6	Murphy, NC	Hydro	Peaking
Mountain Island	1	14	14	Mount Holly, NC	Hydro	Peaking
Mountain Island	2	14	14	Mount Holly, NC	Hydro	Peaking
Mountain Island	3	17	17	Mount Holly, NC	Hydro	Peaking
Mountain Island	4	17	17	Mount Holly, NC	Hydro	Peaking
Nantahala	1	50	50	Topton, NC	Hydro	Peaking
Oxford	1	20	20	Conover, NC	Hydro	Peaking
Oxford	2	20	20	Conover, NC	Hydro	Peaking
Queens Creek	1	1.44	1.44	Topton, NC	Hydro	Peaking
Rhodhiss	1	9.5	9.5	Rhodhiss, NC	Hydro	Peaking
Rhodhiss	2	11.5	11.5	Rhodhiss, NC	Hydro	Peaking
Rhodhiss	3	12.4	12.4	Rhodhiss, NC	Hydro	Peaking
Rocky Creek	1	0	0	Great Falls, SC	Hydro	Peaking
Rocky Creek	2	0	0	Great Falls, SC	Hydro	Peaking
Rocky Creek	3	0	0	Great Falls, SC	Hydro	Peaking
Rocky Creek	4	0	0	Great Falls, SC	Hydro	Peaking

Hydro cont.						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Rocky Creek	5	0	0	Great Falls, SC	Hydro	Peaking
Rocky Creek	6	0	0	Great Falls, SC	Hydro	Peaking
Rocky Creek	7	0	0	Great Falls, SC	Hydro	Peaking
Rocky Creek	8	0	0	Great Falls, SC	Hydro	Peaking
Tuxedo	1	3.2	3.2	Flat Rock, NC	Hydro	Peaking
Tuxedo	2	3.2	3.2	Flat Rock, NC	Hydro	Peaking
Tennessee Creek	1	9.8	9.8	Tuckasegee, NC	Hydro	Peaking
Thorpe	1	19.7	19.7	Tuckasegee, NC	Hydro	Peaking
Tuckasegee	1	2.5	2.5	Tuckasegee, NC	Hydro	Peaking
Wateree	1	17	17	Ridgeway, SC	Hydro	Peaking
Wateree	2	17	17	Ridgeway, SC	Hydro	Peaking
Wateree	3	17	17	Ridgeway, SC	Hydro	Peaking
Wateree	4	17	17	Ridgeway, SC	Hydro	Peaking
Wateree	5	17	17	Ridgeway, SC	Hydro	Peaking
Wylie	1	18	18	Fort Mill, SC	Hydro	Peaking
Wylie	2	18	18	Fort Mill, SC	Hydro	Peaking
Wylie	3	18	18	Fort Mill, SC	Hydro	Peaking
Wylie	4	18	18	Fort Mill, SC	Hydro	Peaking
Total NC		629.37	629.37			
Total SC		468.6	468.6			
Total Hydro		1,097.97	1,097.97			

Solar						
		Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
NC Solar		3.55	3.55	NC	Solar	Intermediate
Total Solar		3.55	3.55			

Nuclear						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
McGuire	1	1160.1	1138.5	Huntersville, NC	Nuclear	Base
McGuire	2	1162.9	1139.6	Huntersville, NC	Nuclear	Base
Catawba	1	1173.7	1140.1	York, SC	Nuclear	Base
Catawba	2	1179.8	1150.1	York, SC	Nuclear	Base
Oconee	1	865	847	Seneca, SC	Nuclear	Base
Oconee	2	872	848	Seneca, SC	Nuclear	Base
Oconee	3	881	859	Seneca, SC	Nuclear	Base
Total NC		2,323	2,278.1			
Total SC		4,971.5	4,844.2			
Total Nuclear		7,294.5	7,122.3			

Total Generation Capability		
	Winter Capacity (MW)	Summer Capacity (MW)
TOTAL DEC SYSTEM - NC	13,578	13,073
TOTAL DEC SYSTEM - SC	8,773	8,500
TOTAL DEC SYSTEM	22,351	21,573

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	19.25%
North Carolina Electric Membership Corporation (NCEMC)	30.75%
NCMPA#1	37.5%
PMPA	12.5%

Planned Uprates			
Unit	Date	Winter MW	Summer MW
McGuire 1[a, b]	Jan 2014	-5.9	9.5
McGuire 2 [a, b]	Jan 2014	-7.1	10.6
Catawba 1[a, b]	Jan 2014	10.7	11.1
Catawba 2 [a, b]	Jan 2014	16.8	21.1
Oconee 1[a, b]	Jan 2014	0	1
Oconee 2[a, b]	Jan 2014	7	2
Oconee 3[a, b]	Jan 2014	16	13
McGuire 1	Jan 2015	20	20
McGuire 2	Jan 2015	20	20
Catawba 1	Mar 2015	20	20
Oconee 1	Jan 2017	15	15
Oconee 2	Jan 2017	15	15
Oconee 3	Jan 2017	15	15

Note (a): The 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, 2014; capacity reflected in Existing Generating Units and Ratings section.

Retirements				
Unit & Plant Name	Location	Capacity (MW) Summer	Fuel Type	Expected Retirement Date
Buck 3	Salisbury, N.C.	75	Coal	RETIRED
Buck 4	Salisbury, N.C.	38	Coal	RETIRED
Cliffside 1	Cliffside, N.C.	38	Coal	RETIRED
Cliffside 2	Cliffside, N.C.	38	Coal	RETIRED
Cliffside 3	Cliffside, N.C.	61	Coal	RETIRED
Cliffside 4	Cliffside, N.C.	61	Coal	RETIRED
Dan River 1	Eden, N.C.	67	Coal	RETIRED
Dan River 2	Eden, N.C.	67	Coal	RETIRED
Dan River 3	Eden, N.C.	142	Coal	RETIRED
Buzzard Roost 6C	Chappels, S.C.	22	Combustion Turbine	RETIRED
Buzzard Roost 7C	Chappels, S.C.	22	Combustion Turbine	RETIRED
Buzzard Roost 8C	Chappels, S.C.	22	Combustion Turbine	RETIRED
Buzzard Roost 9C	Chappels, S.C.	22	Combustion Turbine	RETIRED
Buzzard Roost 10C	Chappels, S.C.	18	Combustion Turbine	RETIRED
Buzzard Roost 11C	Chappels, S.C.	18	Combustion Turbine	RETIRED
Buzzard Roost 12C	Chappels, S.C.	18	Combustion Turbine	RETIRED
Buzzard Roost 13C	Chappels, S.C.	18	Combustion Turbine	RETIRED
Buzzard Roost 14C	Chappels, S.C.	18	Combustion Turbine	RETIRED
Buzzard Roost 15C	Chappels, S.C.	18	Combustion Turbine	RETIRED
Riverbend 8C	Mt. Holly, N.C.	0	Combustion Turbine	RETIRED
Riverbend 9C	Mt. Holly, N.C.	22	Combustion Turbine	RETIRED
Riverbend 10C	Mt. Holly, N.C.	22	Combustion Turbine	RETIRED
Riverbend 11C	Mt. Holly, N.C.	20	Combustion Turbine	RETIRED
Buck 7C	Spencer, N.C.	25	Combustion Turbine	RETIRED
Buck 8C	Spencer, N.C.	25	Combustion Turbine	RETIRED
Buck 9C	Spencer, N.C.	12	Combustion Turbine	RETIRED
Dan River 4C	Eden, N.C.	0	Combustion Turbine	RETIRED
Dan River 5C	Eden, N.C.	24	Combustion Turbine	RETIRED
Dan River 6C	Eden, N.C.	24	Combustion Turbine	RETIRED
Riverbend 4	Mt. Holly, N.C.	94	Coal	RETIRED
Riverbend 5	Mt. Holly, N.C.	94	Coal	RETIRED
Riverbend 6	Mt. Holly, N.C.	133	Coal	RETIRED
Riverbend 7	Mt. Holly, N.C.	133	Coal	RETIRED
Buck 5	Spencer, N.C.	128	Coal	RETIRED
Buck 6	Spencer, N.C.	128	Coal	RETIRED
Lee 1[a]	Pelzer, S.C.	100	Coal	4/15/2015
Lee 2[a]	Pelzer, S.C.	100	Coal	4/15/2015
Lee 3[b]	Pelzer, S.C.	170	Coal	4/15/2015
Total Coal		1,667 MW		
Total CT		370 MW		
Total All		2,037 MW		

Note a: Lee 1 through 3 coal units are planned to be retired as indicated in the table.

Note b: The conversion of the Lee 3 coal unit to a natural gas unit is planned for 4/15/2015.

Planning Assumptions - Unit Retirements[a]				
Unit & Plant Name	Location	Capacity (MW)	Fuel Type	Expected Retirement
Lee 1	Pelzer, S.C.	100	Coal	4/2015
Lee 2	Pelzer, S.C.	100	Coal	4/2015
Lee 3	Pelzer, S.C.	170	Coal	4/2015
Allen 1	Belmont, N.C.	162	Coal	6/2028
Allen 2	Belmont, N.C.	162	Coal	6/2028
Allen 3	Belmont, N.C.	261	Coal	6/2028
Allen 4	Belmont, N.C.	276	Coal	6/2028
Allen 5	Belmont, N.C.	266	Coal	6/2028
Oconee 1[b, c]	Seneca, S.C.	862	Nuclear	5/2033
Oconee 2[b, c]	Seneca, S.C.	863	Nuclear	5/2033
Oconee 3[b, c]	Seneca, S.C.	874	Nuclear	5/2033
Total		3726		

Note a: Retirement assumptions are for planning purposes only; dates are based on useful life expectations of the unit

Note b: Nuclear retirements for planning purposes are based on the end of current operating license

Note c: Oconee capacity includes scheduled uprates (15 MW/unit)

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 2014 forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2015 – 2029 and represents the needs of the following customer classes:

- Residential
- Commercial
- Industrial
- Other Retail
- Wholesale

Energy projections are developed with econometric models using key economic factors such as income, electricity prices, industrial production indices, along with weather and appliance efficiency trends. Population is also used in the residential customer model. 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 2014 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 was derived using a Statistical Adjusted End-Use Model (SAE). This is a regression based framework that uses projected appliance saturation and efficiency trends developed by Itron using EIA data. It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models. The outlook for usage per customer is essentially flat through much of the forecast horizon, so most of the growth is primarily due to customer increases. The projected growth rate of residential in the spring 2014 forecast after all adjustments for utility EE programs, solar and electric vehicles from 2015-2029 is 1.0%.

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 growth rate of 1.5%, after adjustments.

The industrial class forecast is impacted by the level of manufacturing output, exchange rates, electric prices and weather. Overall, industrial sales are expected to grow 0.6% over the forecast horizon, after adjustments.

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.

The Appliance Efficiency Trends are developed by Itron using data from the EIA. Itron is a recognized firm providing forecasting services to the electric utility industry. These appliance trends are used in the residential and commercial sales models.

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

Below are the historical and projected average annual growth rates of several key drivers from DEC's spring 2014 forecast.

	1993-2013	2013-2033
Real GDP	2.9%	2.9%
Real Income	3.1%	2.8%
Population	1.6%	0.9%

In addition to economic, demographic, and efficiency 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.

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 **CONFIDENTIAL**

[redacted]

Historical Values

It should be noted that the long-term structural decline of the textile industry and the recession of 2008-2009 have had an adverse impact on DEC sales. Fortunately, the worst of the textile decline appears to be over, and DEC's economic vendor expects the Carolinas' economy to show solid growth going forward.

Historical information for DEC customers and sales are provided below in Tables C-2 & C-3. The values in Table C-3 are not weather adjusted.

Table C-2

Retail Customers (Thousands, Annual Average)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Residential	1,901	1,935	1,972	2,016	2,052	2,059	2,072	2,081	2,092	2,107
Commercial	313	319	325	331	334	333	334	336	339	341
Industrial	8	7	7	7	7	7	7	7	7	7
Other	12	13	13	13	14	14	14	14	14	14
Total	**2,234**	**2,275**	**2,317**	**2,368**	**2,407**	**2,413**	**2,427**	**2,439**	**2,452**	**2,469**

Table C-3

Electricity Sales (GWh Sold - Years Ended December 31)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Residential	25,150	26,108	25,816	27,459	27,335	27,273	30,049	28,323	26,279	26,895
Commercial	25,204	25,679	26,030	27,433	27,288	26,977	27,968	27,593	27,476	27,765
Industrial	25,209	25,495	24,535	23,948	22,634	19,204	20,618	20,783	20,978	21,070
Other	269	269	271	278	284	287	287	287	290	293
Total Retail	75,833	77,550	76,653	79,118	77,541	73,741	78,922	76,985	75,022	78,035
Wholesale	1,542	1,580	1,694	2,454	3,525	3,788	5,166	4,866	5,176	5,824
Total System	**77,374**	**79,130**	**78,347**	**81,572**	**81,066**	**77,528**	**84,088**	**81,851**	**80,199**	**83,859**

Results

A tabulation of the Utility's forecasts for 2015 - 2029, including peak loads for summer and winter seasons of each year and annual energy forecasts, both with and without the impact of utility-sponsored energy efficiency programs are shown below in Tables C-4 and C-6.

Load duration curves, with and without utility-sponsored EE programs, follow Tables C-5 and C-6, and are shown as Charts C-1 and C-2.

The values in these tables reflect the loads that Duke Energy Carolinas is contractually obligated to provide and cover the period from 2015 to 2029.

The average annual compound growth rates of the needs of the retail and wholesale customer classes are shown in Table C-4 below:

Table C-4 Growth Rates of Retail and Wholesale Customers (2015 – 2029)

	Summer peak demand	Winter peak demand	Energy
Excludes impact of new EE programs	1.8%	1.8%	1.5%
Includes impact of new EE programs	1.4%	1.5%	1.0%

The following tables and charts represent the loads and energy with and without EE. Note that all data below is at the generator.

Table C-5

Load Forecast without Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWh)
2015	18,588	17,360	96,406
2016	18,986	17,737	98,389
2017	19,360	18,128	100,282
2018	19,745	18,509	102,208
2019	20,172	18,934	103,883
2020	20,516	19,199	105,099
2021	20,815	19,485	106,268
2022	21,146	19,771	107,487
2023	21,492	20,092	108,732
2024	21,896	20,478	110,173
2025	22,232	20,829	111,411
2026	22,597	21,180	112,752
2027	22,987	21,520	114,553
2028	23,425	21,933	116,440
2029	23,748	22,243	118,194

Note: Table 8-C differs from these values due to a 47 MW PMPA backstand contract through 2020.

Chart C-1 Load Duration Curve without Energy Efficiency Programs

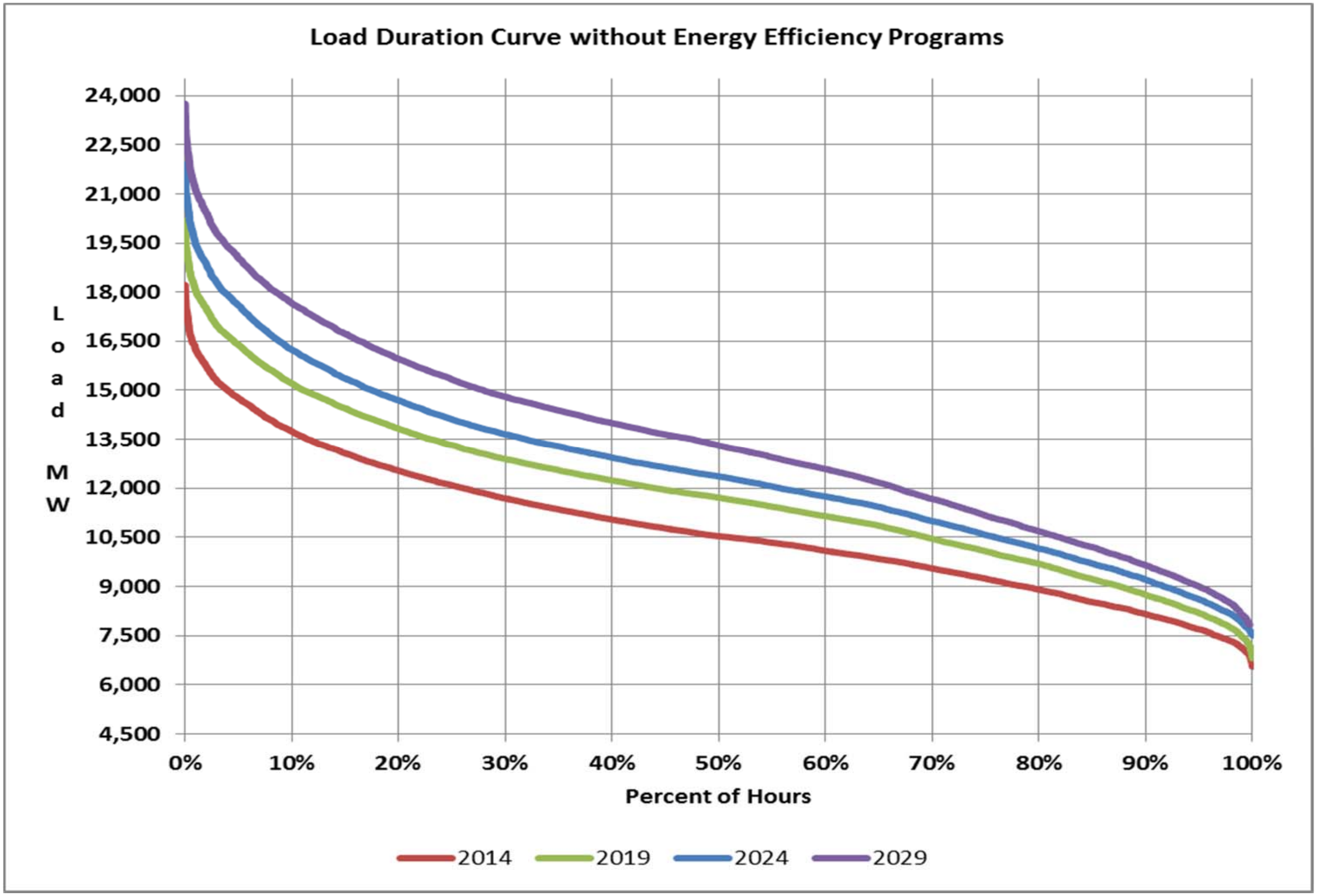
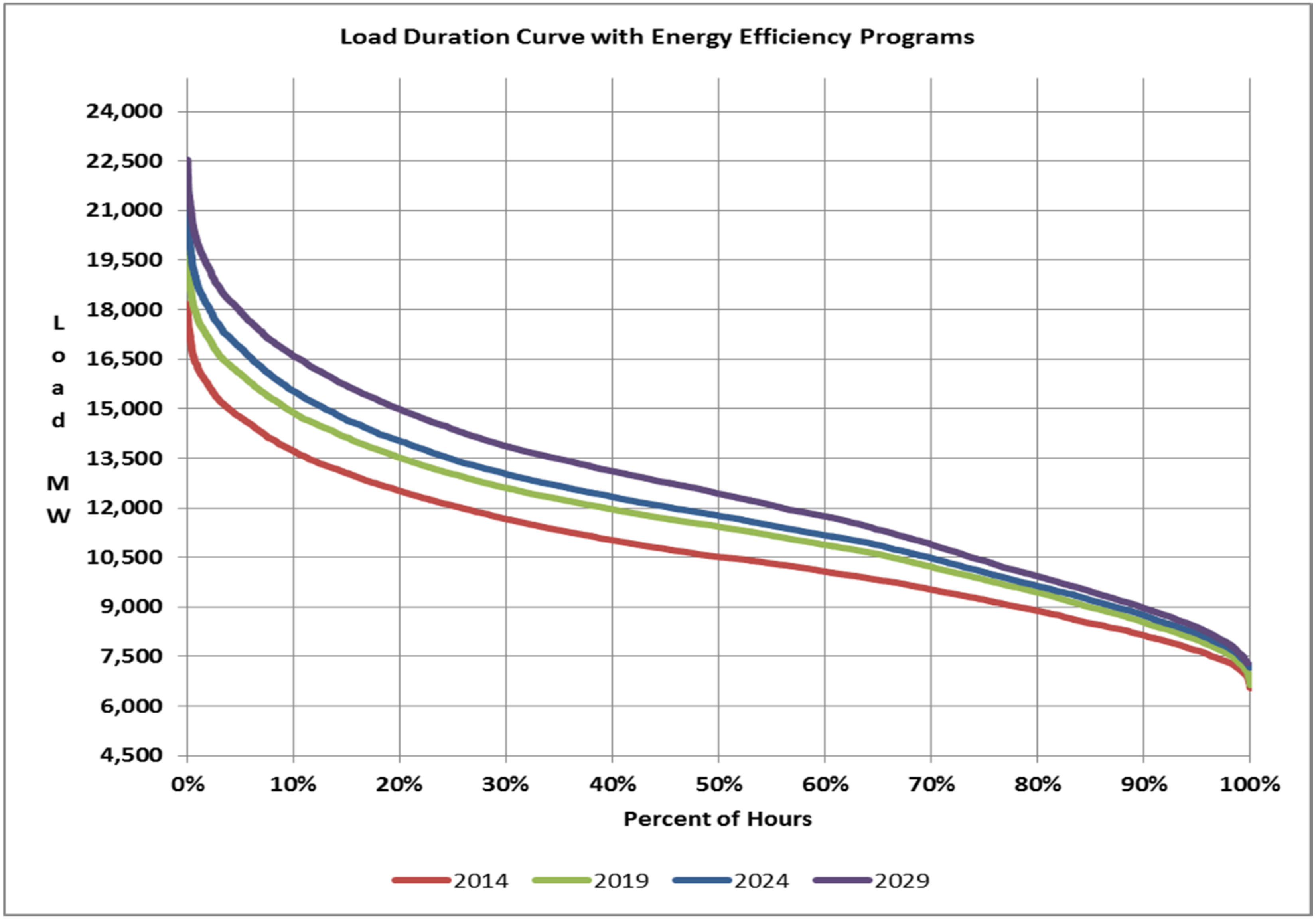


Table C-6
Load Forecast with Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWh)
2015	18,486	17,303	95,763
2016	18,822	17,637	97,329
2017	19,130	17,982	98,789
2018	19,448	18,317	100,271
2019	19,806	18,672	101,484
2020	20,076	18,882	102,221
2021	20,291	19,105	102,873
2022	20,529	19,322	103,515
2023	20,777	19,570	104,150
2024	21,085	19,883	104,983
2025	21,320	20,158	105,618
2026	21,595	20,440	106,399
2027	21,906	20,721	107,713
2028	22,276	21,083	109,158
2029	22,537	21,346	110,555

Note: Table 8-C differs from these values due to a 47 MW PMPA backstand contract through 2020.

Chart C-2 Load Duration Curve with Energy Efficiency Programs



APPENDIX D: ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT

Current Energy Efficiency and Demand-Side Management Programs

In 2013, DEC filed its application for approval of Energy Efficiency and Demand Side Management programs under North Carolina Docket No. E-7, Sub 1032 and South Carolina Docket 2013-298-E. This new portfolio was a replacement for the save-a-watt programs approved in 2009/2010. The Company received the final order for approval for these programs from the NCUC in October 2013 and from the PSCSC in December 2013.

DEC uses EE and DSM programs in its IRP to efficiently and cost-effectively alter customer demands and reduce the long-run supply costs for energy and peak demand. 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 Customer Programs

- Appliance Recycling Program
- Energy Assessments Program
- Energy Efficiency Education Program
- Energy Efficient Appliances and Devices
- Heating, Ventilation and Air Conditioning (HVAC) Energy Efficiency Program
- Multi-Family Energy Efficiency Program
- My Home Energy Report
- Income-Qualified Energy Efficiency and Weatherization Program
- Power Manager

Non-Residential Customer Programs

- Non-Residential Smart $aver® Energy Efficient Food Service Products Program
- Non-Residential Smart $aver® Energy Efficient HVAC Products Program
- Non-Residential Smart $aver® Energy Efficient IT Products Program
- Non-Residential Smart $aver ®Energy Efficient Lighting Products Program
- Non-Residential Smart $aver® Energy Efficient Process Equipment Products Program
- Non-Residential Smart $aver® Energy Efficient Pumps and Drives Products Program
    - Non-Residential Smart $aver® Custom Program
    - Non-Residential Smart $aver® Custom Energy Assessments Program
    - PowerShare®

- PowerShare® CallOption

In addition, based on feedback from stakeholders, the Company has developed a pilot program for non-residential customers and has included it in this filing for Commission approval, so that it may determine the potential impacts and cost-effectiveness of this new program.

Pilot Program

- Energy Management and Information Services Program

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 2013 are already reflected in the customer load forecast and summarized below. The following provides more detail on DEC's existing EE programs:

Residential Programs

Appliance Recycling Program promotes the removal and responsible disposal of inefficient appliances. Currently, the program provides incentives to customers targeting the removal of inefficient operating refrigerators and freezers from Duke Energy Carolinas' residential customers. After collection of the appliances, approximately 95% of the material is recycled from the harvested appliances. This program is available to customers who own operating refrigerators and freezers used in individually-metered residences. The refrigerator or freezer must have a capacity of at least 10 cubic feet but not more than 30 cubic feet.

Appliance Recycling Program			
Cumulative as of:	**Participants**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2013	11,277	18,654	3,461

Energy Assessments Program (formerly known as Home Energy House Call) assists residential customers in assessing their energy usage and provides recommendations for more efficient use of energy in their homes. The program also helps identify those customers who could benefit most by investing in new EE measures, undertaking more EE practices and participating in other Duke Energy Carolinas EE and DSM programs. This program includes Home Energy House Call, which provides eligible customers with a free in-home assessment designed to help customers reduce energy usage and save money. A Building Performance Institute-certified energy specialist completes a 60 to 90 minute walk-through assessment of the home and analyzes energy usage to identify energy saving opportunities. The specialist discusses behavioral and equipment modifications that can save energy and money with the customer and provides a customized report to the customer that identifies specific actions the customer can take to increase their home efficiency. Participating customers will also receive an Energy Efficiency Starter Kit with a variety of measures that can be directly installed by the energy specialist.

Home Energy House Call			
Cumulative as of:	**Participants**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2013	29,050	28,822	5,339

Two previously offered Residential Energy Assessment measures are no longer offered in the new portfolio effective January 1, 2014. The historical performance of these measures through December 31, 2013 is included below.

Personalized Energy Report			
Cumulative as of:	**Participants**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2013	86,333	24,502	2,790

Online Home Energy Comparison Report			
Cumulative as of:	**Participants**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2013	12,902	3,547	387

Energy Efficiency Education Program is designed to educate students in grades K-12 about energy and the impact they can have by becoming more energy efficient and using energy more wisely. In conjunction with teachers and administrators, the Company will provide educational materials and curriculum for targeted schools and grades that meet grade-appropriate state education standards. The curriculum and engagement method may vary over time to adjust to market conditions, but currently utilizes theatre to deliver the program into the school. Enhancing the message with a live theatrical production truly captures the children’s attention and reinforces the classroom and take-home assignments. Students learn about EE measures in the Energy Efficiency Starter Kit and then implement these energy saving measures in their homes. Students are sharing what they have learned with their parents and helping their entire households learn how to save more energy.

Energy Efficiency Education Program			
Cumulative as of:	**Participants**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2013	81,034	21,299	3,951

Energy Efficient Appliances and Devices Program (formerly part of Residential Smart $aver® program) provides incentives to residential customers for installing energy efficient appliances and devices to drive reductions in energy usage. The program includes the following measures:

- Energy Efficient Pool Equipment: This measure encourages the purchase and installation of energy efficient equipment and controls. Initially, the measure will focus on variable speed pumps, but the pool equipment offerings may evolve with the marketplace to include additional equipment options and control devices that reduce energy consumption and/or demand.

- Energy Efficient Lighting: This measure encourages the installation of energy efficient lighting products and controls. The product examples may include, but are not limited to the following: standard CFLs, specialty CFLs, A lamp LEDs, specialty LEDs, CFL fixtures, LED fixtures, 2X incandescent, LED holiday lighting, motion sensors, photo cells, timers, dimmers and daylight sensors.

- Energy Efficient Water Heating and Usage: This measure encourages the adoption of heat pump water heaters, insulation, temperature cards and low flow devices.

- Other Energy Efficiency Products and Services: Other cost-effective measures may be added to in-home installations, purchases, enrollments and events. Examples of additional measures may include, without limitation, outlet gaskets, switch gaskets, weather stripping, filter whistles, fireplace damper seals, caulking, smart strips and energy education tools/materials.

Residential Smart $aver® Program – Residential CFLs			
Cumulative as of:	**Participants (CFLs)**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2013	24,002,460	1,010,996	106,860

Residential Smart $aver® Program – Specialty Lighting			
Cumulative as of:	**Participants (bulbs)**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2013	117,057	5,376	525

Heating, Ventilation, and Air Conditioning (HVAC) Energy Efficiency Program (formerly part of Residential Smart $aver® program) provides residential customers with opportunities to lower their home's electric use through maintenance and improvements to their central HVAC system(s) as well as the structure of their home's building envelope and duct system(s). This program reaches Duke Energy Carolinas customers during the decision-making process for measures included in the program. Each measure offered through the program will have a prescribed incentive associated with successful completion by an approved contractor. The prescriptive and a-la-carte design of the program allows customers to implement individual, high priority measures in their homes without having to commit to multiple measures and higher price tags. The measures eligible for incentives through the program are:

- Central Air Conditioner
- Heat Pump
- Attic Insulation and Air Sealing
- Duct Sealing
- Duct Insulation
- Central Air Conditioner Tune Up
- Heat Pump Tune Up

Residential Smart $aver® Program -- HVAC			
Cumulative as of:	**Participants**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2013	47,021	42,098	8,907

Residential Smart $aver® Program -- Tune and Seal			
Cumulative as of:	**Participants**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2013	451	263	73

Multi-Family Energy Efficiency Program provides energy efficient technologies to be installed in multi-family dwellings, which include, but are not limited to, the following:

- Energy Efficient Lighting
- Energy Efficient Water Heating Measures
- Other cost-effective measures may be added to in-home installations, purchases, enrollments and events. Examples of additional measures may include, without limitation, outlet gaskets, switch gaskets, weather stripping, filter whistles, fireplace damper seals, caulking, smart strips and energy education tools/materials.

Residential Smart $aver® Program – Property Manager CFLs			
Cumulative as of:	**Participants (CFLs)**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2013	909,898	39,213	4,039

My Home Energy Report Program provides residential customers with a comparative usage report up to twelve times a year that engages and motivates customers by comparing energy use to similar residences in the same geographical area based upon the age, size and heating source of the home. The report also empowers customers to become more efficient by providing them with specific energy saving recommendations to improve the efficiency of their homes. The actionable energy savings tips, as well as measure-specific coupons, rebates or other Company program offers that may be included in a customer's report are based on that specific customer's energy profile.

My Home Energy Report Program			
Cumulative as of:	**Participants**	**Capability (MWh)**	**Summer Capability (kW)**
December 31, 2013	722,069	143,256	30,310

Note: The capability for the MyHER Program shown above is lower than what was reported in the 2012 IRP, even though the participation has increased, due to the application of M&V.

Income-Qualified Energy Efficiency and Weatherization Program consists of three distinct components designed to provide EE to different segments of its low income customers:

- The Residential Neighborhood Program ("RNP") is available only to individually-metered residences served by Duke Energy Carolinas in neighborhoods selected by the Company, which are considered low-income based on third party and census data, which includes income level and household size. Neighborhoods targeted for participation in this program will typically have approximately 50% or more of the households with income up to 200% of the poverty level established by the U.S. Government. This approach allows the Company to reach a larger audience of low income customers than traditional government agency flow-through methods. The program provides customers with the direct installation of measures into the home to increase the EE and comfort level of the home. Additionally, customers receive EE education to encourage behavioral changes for managing energy usage and costs.

  The Company recognizes the existence of customers whose EE needs surpass the standard low cost measure offerings provided through RNP. In order to accommodate customers needing this more substantial assistance, the Company will also offer the following two programs that piggy-back on the existing government-funded North Carolina Weatherization Assistance Program when feasible. Collaborating with these programs will result in a reduction of overhead and administration costs.

- The Weatherization and Equipment Replacement Program ("WERP") offers weatherization services and equipment replacement of electric heating systems. Weatherization services are available to individually-metered, single-family residences served by Duke Energy Carolinas on a residential rate schedule. Income eligibility requirements for WERP will mirror the income eligibility standards for the North Carolina Weatherization Assistance Program.

- The Refrigerator Replacement Program ("RRP") includes, but is not limited to, replacement of inefficient operable refrigerators in low income households. The program will be available to homeowners, renters, and landlords with income qualified tenants that own a qualified appliance. Income eligibility for RRP will mirror the income eligibility standards for the North Carolina Weatherization Assistance Program.

Income Qualified Energy Efficiency and Weatherization Program			
Cumulative as of:	**Participants**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2013	16,963	10,284	1,309

<u>Non-Residential</u>

Non-Residential Smart $aver® Energy Efficient Food Service Products Program provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency food service equipment in new and existing non-residential establishments and repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, commercial refrigerators and freezers, steam cookers, pre-rinse sprayers, vending machine controllers, and anti-sweat heater controls.

Non-Residential Smart $aver® Energy Efficient HVAC Products Program provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficient HVAC equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, chillers, unitary and rooftop air conditioners, programmable thermostats, and guest room energy management systems.

Non-Residential Smart $aver® Energy Efficient IT (Information Technologies) Products Program provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of high efficiency new IT equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance efficiency levels in currently-installed equipment. Measures include, but are not limited to, Energy Star-rated desktop computers and servers, PC power management from network, server virtualization, variable frequency drives ("VFD") for computer room air conditioners and VFD for chilled water pumps.

Non-Residential Smart $aver® Energy Efficient Lighting Products Program provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency lighting equipment in new and existing non-residential establishments and the efficiency-directed repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, interior and exterior LED lamps and fixtures, reduced wattage and high performance T8 systems, T8 and T5 high bay fixtures, and occupancy sensors.

Non-Residential Smart $aver® Energy Efficient Process Equipment Products Program provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance high efficiency levels in currently installed equipment. Measures include, but are not limited to, VFD air compressors, barrel wraps, and pellet dryer insulation.

Non-Residential Smart $aver® Energy Efficient Pumps and Drives Products Program provides prescriptive incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency equipment in new and existing non-residential establishments and efficiency-directed repairs to maintain or enhance efficiency levels in currently installed equipment. Measures include, but are not limited to, pumps and VFD on HVAC pumps and fans.

Non-Residential Smart $aver® Custom Program provides custom incentive payments to non-residential customers to encourage and partially offset the cost of the installation of new high efficiency equipment in new and existing non-residential establishments. This program allows for eligible customers to apply for and the Company to provide custom incentives in the amount up to 75% of the installed cost difference between standard equipment and new higher efficiency equipment or efficiency-directed repair activities in order to cover measures and efficiency-driven activities that are not offered in the various Non-Residential Smart $aver prescriptive programs.

Non-Residential Smart $aver® Custom Energy Assessments Program provides customers who may be unaware of EE opportunities at their facilities with a custom incentive payment in the amount up to 50% of the costs of a qualifying energy assessment. The purpose of this component of the program is to overcome financial barriers by off-setting a customer's upfront costs to identify and evaluate EE projects that will lead to the installation of energy efficient measures. The scope of an energy assessment may include but is not limited to a facility energy audit, a new construction/renovation energy performance simulation, a system energy study and retro-commissioning service. After the energy assessment is complete, program participants may receive an additional custom incentive payment in the amount of up to 75% of the installed cost difference between standard equipment and higher efficiency equipment or efficiency-directed repair activities.

Non-Residential Smart $aver® Program			
Cumulative as of:	**Measures**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2013	1,677,205	844,118	139,331

Small Business Energy Saver Program is modeled after the SBES program offered by Duke Energy Progress. The primary objective of the Program is to reduce energy usage by improving energy efficiency through the offer and installation of eligible energy efficiency measures. Program measures will address major end-uses in lighting, refrigeration, and HVAC applications. The Program is available to existing non-residential establishments served on a Duke Energy Carolinas general service or industrial rate schedule from the Duke Energy Carolinas' retail distribution system that are not opted-out of the EE portion of Rider EE. Program participants must have an average annual demand of 100 kW or less per active account. Participants may be owner-occupied or tenant facilities with owner permission.

This program was recently approved to be offered in South Carolina and on August13, 2014, was also approved by the NCUC in North Carolina.

Smart Energy in Offices Program is designed to increase the energy efficiency of targeted customers by engaging building occupants, tenants, property managers and facility teams with information, education, and data to drive behavior change and reduce energy consumption. This Program will leverage communities to target owners and managers of potential participating accounts by providing participants with detailed information on the account/building's energy usage, support to launch energy saving campaigns, information to make comparisons between their building's energy performance and others within their community and actionable recommendations to improve their energy performance. The Program is available to existing non-residential accounts located in eligible commercial buildings served on a Duke Energy Carolinas' general service rate schedule from the Duke Energy Carolinas' retail distribution system that are not opted out of the EE portion of the Rider EE.

This program was recently approved to be offered in South Carolina and on August13, 2014, was also approved by the NCUC in North Carolina.

Pilot

Energy Management and Information Services Pilot is designed to test providing qualified commercial or institutional customer facilities with a systematic approach to reduce energy and persistently maintain the savings over time. The Company will provide the customer with an energy management and information system ("EMIS") Software-as-a-Service ("SaaS") and perform a remote or light on-site energy assessment focused on low-cost operational EE measures. The EMIS SaaS will use interval meter data from the customer's meter to give valuable insights into areas where efficiency has been gained as well as additional opportunities for efficiency. The customer will also implement a bundle of low cost operational and maintenance-based energy efficient measures that meet certain financial investment criteria.

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 due to the participant not having to directly respond to an event. DEC's current direct load control programs are:

Residential

Power Manager® provides residential customers a voluntary demand response program that allows Duke Energy Carolinas to limit the run time of participating customers' central air conditioning (cooling) systems to reduce electricity demand. Power Manager may be used to completely interrupt service to the cooling system when the Company experiences capacity problems. In addition, the Company may intermittently interrupt (cycle) service to the cooling system. For their participation in Power Manager, customers receive bill credits during the billing months of June through September.

Power Manager 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 Program			
As of:	**Participants (customers)**	**Devices (switches)**	**Summer 2013 Capability (MW)**
December 31, 2013	157,538	185,078	328

Source: Impact Evaluation and Review of the 2013 Power Manager® Program for the Carolina System, May 30, 2014

The following table shows Power Manager® program activations that were not for testing purposes from June 1, 2011 through December 31, 2013.

Power Manager® Program 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
July 18, 2013 – 2:30 PM	July 18, 2013 – 5:00 PM	150	116
July 19, 2013 – 1:30 PM	July 19, 2013 – 4:00 PM	150	112
July 24, 2013 – 1:30 PM	July 24, 2013 – 4:00 PM	150	150
August 12, 2013 – 1:30 PM	August 12, 2013 – 4:00 PM	150	158
August 29, 2013 – 1:30 PM	August 29, 2013 – 4:00 PM	150	157
September 10, 2013 – 2:30 PM	September 10, 2013 – 5:00 PM	150	143
September 11, 2013 – 2:30 PM	September 11, 2013 – 5:30 PM	180	123

** The values in this table represent events during which Power Manager switches were cycled, and do not reflect the full shed potential of the switch.*
*** MW Load Reduction is the average load reduction "at the generator" over the event period for full clock hours.*

Source: Impact Evaluation and Review of the 2013 Power Manager® Program for the Carolina System, May 30, 2014

Non-Residential

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 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 Program		
As of:	**Participants**	**Summer 2013 Capability (MW)**
December 31, 2013	61	133

The following table shows IS program activations that were <u>not</u> for testing purposes from June 1, 2011 through December 31, 2013.

IS Program 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 Program		
As of:	**Participants**	**Summer 2013 Capability (MW)**
December 31, 2013	82	39

The following table shows SG program activations that were not for testing purposes from June 1, 2011 through December 31, 2013.

SG Program 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 Program		
As of:	**Participants**	**Summer 2013 Capability (MW)**
December 31, 2013	180	363

The following table shows PowerShare® Mandatory program activations that were not for testing purposes from June 1, 2011 through December 31, 2013.

PowerShare® Mandatory Program 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 2013 Capability (MW)**
December 31, 2013	9	11

The following table shows PowerShare® Generator program activations that were not for testing purposes from June 1, 2011 through December 31, 2013.

PowerShare® Generator Program 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 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 Program		
As of:	**Participants**	**Summer Capability (MW)**
December 31, 2012	8	N/A

The following table shows PowerShare® Voluntary program activations that were not for testing purposes from June 1, 2011 through December 31, 2013.

PowerShare® Voluntary Program 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 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 Program		
As of:	**Participants**	**Summer 2013 Capability (MW)**
December 31, 2013	0	.03

Note: Customer was available for Summer 2013 Capability but left program prior to December 31, 2013.

The following table shows PowerShare® CallOption program activations that were not for testing purposes from June 1, 2011 through December 31, 2013.

PowerShare® CallOption Program 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 was not available for customer participation until January 1, 2014.

PowerShare® CallOption 200 Program		
As of:	**Participants**	**Summer Capability (MW)**
December 31, 2013	0	N/A

The table below incorporates December 31, 2013 participation levels for demand response programs and the capability of these programs projected for the summer of 2014.

Demand Side Management Programs and Capability		
Program Name	**Program Participation as of 12/31/13**	**2014 Estimated Summer IRP Capability (MW)**
IS	61	165
SG	82	19
PowerShare® Mandatory	180	364
PowerShare® Generator	9	30
PowerShare® Voluntary	8	N/A
PowerShare® CallOption	-	-
-- Level 0/5	0	N/A
-- Level 5/5	0	N/A
-- Level 10/5	0	N/A
-- Level 15/5	0	N/A
-- Level 200	0	N/A
Total	**340**	**608**
Power Manager® (Switches)	185,078	429
Grand Total	**-**	**1,007**

Source: 2014 DEC IRP Forecast, Base Case

Related Rate Tariffs

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 already included in the assessment of generation needs due to the fact that their historical impacts are captured in the forecast of loads.

Future EE and DSM programs

DEC is continually seeking to enhance its EE and DSM portfolio by: (1) adding new programs or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new M&V results, and (3) other EE pilots.

Potential new programs and/or measures will be reviewed with the DSM Collaborative then submitted to the Public Utility Commissions as required for approval.

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

The Public Staff, in their comments on the 2013 IRP filing, Docket E-100, Sub137, made the following recommendations relative to EE/DSM analysis and forecasts:

9. *The IOUs should continue to monitor and report any changes of more than 10% in the energy and capacity savings derived from DSM / EE between successive IRPs, and evaluate and discuss any changes on a program specific basis. Any issues impacting program deployment should be thoroughly explained and quantified in future IRPs.*

10. *The IOUs should develop a consistent method of evaluating their DSM / EE portfolios and incorporate the savings in a manner that provides a clearer understanding of the year-by-year changes occurring in the portfolios and their impact on the load forecast and resource plan in future IRPs. The savings impacts should be represented on a net basis, taking into account any NTG impacts derived through EM&V processes.*

11. *DEP and DEC should specifically identify the values of DSM / EE portfolio capacity and energy savings separately in their load forecast tables and not embed these values in the system peak load or energy.*

12. *The IOUs should account for all of their DSM / EE program savings from programs approved pursuant to G.S. 62-133.9 and Commission Rule R8-68, regardless of when those measures were installed.*

13. *DEP and DEC should each adopt one methodology of evaluating the DSM / EE components of the IRP and remain consistent year-to-year. If an IOU determines that a change in methodology is required or appropriate, these changes should be thoroughly explained, justified, and reconciled to the savings projected in the previous IRP.*

In response to Recommendation Number 13 above, there were no significant changes in the EE forecast methodology for the 2014 IRP.

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 estimation were blended together with the DEC forecast for the 5-year planning horizon to create an overall forecast that used the same methodology to the 2013 DEC IRP for the first 5 years. For years 6 through 10, DEC interpolated between the cumulative achievements at the end of Year 5 and the expected achievements from the Forefront study starting in Year 10. For years 11 through 20, DEC used the incremental achievements estimated by Forefront.

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 as well as the timing of the introduction of those programs. 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, feedback from the DSM Collaborative and with the possible assistance of implementation contractors.

The tables below provide 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 on a Gross and Net of Free Riders basis (responsive to Recommendation Number 10 above). 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. Please note that, in response to Recommendation Number 12 above, this table includes a column that shows historical EE program savings since the inception of the EE programs in 2009 through the end of 2013, which accounts for approximately an additional 2,207 GWh of energy savings and 310 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 - Gross Including Free Riders

	Annual MWh Load Reduction		Annual Peak MW Reduction					
Year	Including measures added in 2014 and beyond	Including measures added since 2009	EE	IS	SG	PowerShare	PowerManager	Total Annual Peak
2009-13		2,206,536						
2014	439,799	2,646,334	37	165	19	394	429	1,044
2015	845,866	3,052,401	101	157	19	416	440	1,132
2016	1,272,833	3,479,369	164	149	18	435	453	1,219
2017	1,712,712	3,919,247	230	141	17	453	465	1,307
2018	2,161,679	4,368,214	297	135	16	466	474	1,387
2019	2,637,421	4,843,957	366	129	15	477	479	1,465
2020	3,119,267	5,325,803	440	126	15	481	479	1,541
2021	3,670,534	5,877,069	524	126	15	481	479	1,625
2022	4,272,614	6,479,150	617	126	15	481	479	1,718
2023	4,891,005	7,097,541	715	126	15	481	479	1,816
2024	5,489,403	7,695,938	811	126	15	481	479	1,912
2025	6,097,058	8,303,594	912	126	15	481	479	2,013
2026	6,607,562	8,814,097	1,002	126	15	481	479	2,103
2027	7,073,440	9,279,976	1,081	126	15	481	479	2,182
2028	7,490,168	9,696,704	1,149	126	15	481	479	2,250
2029	7,788,479	9,995,015	1,211	126	15	481	479	2,312

Base Case Load Impacts of EE and DSM Programs - Net of Free Riders

	Annual MWh Load Reduction		Annual Peak MW Reduction					
Year	Including measures added in 2014 and beyond	Including measures added since 2009	EE	IS	SG	PowerShare	PowerManager	Total Annual Peak
2009-13		2,002,276						
2014	345,835	2,348,111	29	165	19	394	429	1,036
2015	653,108	2,655,384	78	157	19	416	440	1,109
2016	976,403	2,978,679	126	149	18	435	453	1,181
2017	1,309,430	3,311,706	176	141	17	453	465	1,252
2018	1,650,017	3,652,293	227	135	16	466	474	1,317
2019	1,958,096	3,960,373	272	129	15	477	479	1,371
2020	2,240,365	4,242,641	316	126	15	481	479	1,417
2021	2,561,605	4,563,882	366	126	15	481	479	1,467
2022	2,910,953	4,913,229	420	126	15	481	479	1,521
2023	3,267,544	5,269,820	478	126	15	481	479	1,579
2024	3,611,736	5,614,013	534	126	15	481	479	1,635
2025	3,958,855	5,961,131	592	126	15	481	479	1,693
2026	4,255,408	6,257,684	645	126	15	481	479	1,746
2027	4,527,686	6,529,962	692	126	15	481	479	1,793
2028	4,773,912	6,776,188	732	126	15	481	479	1,833
2029	4,952,720	6,954,997	770	126	15	481	479	1,871

**Please note that the MWh totals included in the tables above represent the annual year-end impacts associated with EE programs, however, the MWh totals included in the load forecast portion of this document represent the sum of the expected hourly impacts.*

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

In response to Recommendation Number 9 from the Public Staff, the Base Case EE savings forecast of MW and MWh is within 10% of the forecast presented in the 2013 IRP when compared on the cumulative achievements at year 15 of the forecast, however, the current forecast is different from the forecast presented in the 2013 DEC IRP in the following ways:

- The 2014 IRP is based on an updated forecast of DEC's 5 year planning horizon for the period of 2014-18.
- The 2014 Base Case forecast includes an assumption related to new, as yet unidentified EE products that is lower than the similar assumption in the 2013 Base Case forecast. This lower assumption is based on the historical performance of new products added since the original EE portfolio filing in 2009 and projections of future program versus the higher expected savings included in the 2013 IRP.

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.

The tables below show the expected High Case savings treated as a sensitivity in this IRP on both Gross and Net of Free Riders basis.

High Case Load Impacts of EE and DSM Programs - Gross Including Free Riders

	Annual MWh Load Reduction		Annual Peak MW Reduction					
Year	Including measures added in 2014 and beyond	Including measures added since 2009	EE	IS	SG	PowerShare	PowerManager	Total Annual Peak
2009-13		2,206,536						
2014	439,799	2,646,335	37	165	19	394	429	1,044
2015	1,262,967	3,469,502	134	157	19	416	440	1,165
2016	2,093,510	4,300,045	260	149	18	435	453	1,315
2017	2,928,929	5,135,465	386	141	17	453	465	1,463
2018	3,768,370	5,974,905	514	135	16	466	474	1,604
2019	4,611,871	6,818,406	639	129	15	477	479	1,738
2020	5,459,178	7,665,714	770	126	15	481	479	1,871
2021	6,308,739	8,515,275	908	126	15	481	479	2,009
2022	7,160,581	9,367,117	1,046	126	15	481	479	2,147
2023	8,014,797	10,221,333	1,184	126	15	481	479	2,285
2024	8,871,662	11,078,197	1,319	126	15	481	479	2,420
2025	9,732,783	11,939,319	1,464	126	15	481	479	2,565
2026	10,596,710	12,803,246	1,604	126	15	481	479	2,705
2027	11,464,059	13,670,595	1,744	126	15	481	479	2,845
2028	12,339,200	14,545,736	1,879	126	15	481	479	2,980
2029	13,222,537	15,429,073	2,026	126	15	481	479	3,127

High Case Load Impacts of EE and DSM Programs - Net of Free Riders

	Annual MWh Load Reduction		Annual Peak MW Reduction					
Year	Including measures added in 2014 and beyond	Including measures added since 2009	EE	IS	SG	PowerShare	PowerManager	Total Annual Peak
2009-13		2,002,276						
2014	345,835	2,348,111	29	165	19	394	429	1,036
2015	975,159	2,977,435	103	157	19	416	440	1,135
2016	1,605,951	3,608,228	199	149	18	435	453	1,254
2017	2,239,272	4,241,548	295	141	17	453	465	1,372
2018	2,876,410	4,878,686	392	135	16	466	474	1,483
2019	3,423,984	5,426,260	474	129	15	477	479	1,574
2020	3,920,970	5,923,246	553	126	15	481	479	1,654
2021	4,402,766	6,405,042	634	126	15	481	479	1,735
2022	4,878,539	6,880,815	713	126	15	481	479	1,814
2023	5,354,462	7,356,738	791	126	15	481	479	1,892
2024	5,837,084	7,839,360	868	126	15	481	479	1,969
2025	6,319,551	8,321,828	951	126	15	481	479	2,052
2026	6,824,503	8,826,779	1,033	126	15	481	479	2,134
2027	7,338,107	9,340,383	1,116	126	15	481	479	2,217
2028	7,864,477	9,866,753	1,198	126	15	481	479	2,299
2029	8,408,256	10,410,533	1,288	126	15	481	479	2,389

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 2014 IRP. However, the high EE savings forecast was evaluated in two portfolios included in this IRP. 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.

Duke Energy Carolinas 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 Duke Energy Carolinas 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.

The deployment of an IVVC program for Duke Energy Carolinas is anticipated to take approximately 4 years following project approval. This IVVC program is projected to reduce future distribution-only peak needs by 0.20% in 2017, 0.4% in 2018, 0.6% in 2019, 1.0% in 2020 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 a significant amount of combined cycle generation. 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 relatively stable year (2013) for North American gas producers, 2014 started with extreme weather resulting from the "Polar Vortex" and subsequent cold weather events across broad regions including the Northeast, Midwest, Mid-Atlantic, and Southeast in January 2014, and extended into Texas and the Southwest in February 2014. A new daily US gas demand record was established and pipelines managed the extreme demand by instituting operational flow orders across the regions. With the extremely cold winter, storage levels ended the season at an eleven year low. With the extreme and sustained winter weather, spot natural gas prices experienced extreme volatility across various regions. In addition, forward market prices for the balance of 2014 and 2015 increased on the expectation that storage balances going into the winter of 2014/2015 are below historical levels.

However, the market for the balance of 2014 and 2015 has declined recently given the level of injections over the past three months. As such, near term Henry Hub natural gas prices have declined after the increase observed through the winter and forward prices for the balance of 2014 through 2018 are expected to be in the $4.00 to $4.50 range. Although risk remains to end of season inventory levels, the recent level of injections has removed some concerns over inventories ending the season at the lower end of historical ranges. Gas 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 EPA's 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. Lastly, although the outcome and timing is uncertain, there could be additional gas demand as a result of the recently announced EPA requirement to reduce carbon emissions.

The long-term fundamental gas price outlook is little changed from the 2013 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 billion cubic feet per day (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 in this outlook).

In order to ensure adequate natural gas supplies, the Company has gas procurement practices that include periodic RFPs, market solicitations, and short-term market engagement activities to procure a reliable, flexible, diverse, and competitively priced natural gas supply that supports DEC's CT and CC facilities.

Coal

On average, the 2014 Duke fundamental outlook for coal prices is lower than the 2013 outlook, although Central Appalachian (CAPP) sourced coals may see higher prices return in the near-term primarily as a result of deterioration in mine productivity, mine closures and higher cost operations.

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 Northern Appalachian (NAP)) are projected to remain constant while export steam coal will respond to global demand. When export steam growth occurs, it will be driven primarily in the Illinois Basin (ILB) due to superior productivity and lower costs, which will be delivered, to Atlantic markets via the Gulf of Mexico.

Nuclear Fuel

To provide fuel for Duke Energy's 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, DEC 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, DEC 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 are expected to be competitive with alternate generation and customers will continue to benefit from the Company's diverse generation mix.

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 relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves. The technologies must be technically and economically viable in order to be passed on to the detailed analysis phase of the IRP process.

<u>Technical Screening</u>

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. The Company 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, the U.S. Department of Energy (DOE) solicited bids for companies to participate in a small modular reactor grant program with the intent to "promote the accelerated commercialization of SMR technologies to help meet the nation's economic energy security and climate change objectives." SMRs are still conceptual in design and are developmental in nature. Currently, there is no industry experience with developing this technology outside of the conceptual phase. Duke Energy will be monitoring the progress of the SMR project for potential consideration and evaluation for future resource plans.

- 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.

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 supercritical pulverized coal (SCPC) with carbon capture sequestration (CCS) and integrated gasification combined cycle (IGCC) technologies with CCS of 1100 pounds/net MWh as options for base load analysis consistent with the EPA New Source Performance Standards (NSPS) rules. Additional detail on the expected impacts from EPA regulations to new coal-fired options is included in Appendix G.

- Base load – 723 MW Supercritical Pulverized Coal with CCS
- Base load – 525 MW IGCC with CCS
- Base load – 2 x 1,117 MW Nuclear units (AP1000)
- Base load – 688 MW – 2x2x1 Combined Cycle (Inlet Chiller and Fired)
- Base load – 866 MW – 2x2x1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Base load – 1,302 MW – 3x3x1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Peaking/Intermediate – 173 MW 4-LM6000 CTs
- Peaking/Intermediate – 792 MW 4-7FA CTs
- Renewable – 150 MW Wind - On-Shore
- Renewable – 5 MW Landfill Gas
- 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 Project Development and Initiation, Emerging Technologies, and Strategic Engineering. The following external sources may also be utilized: proprietary third-party engineering studies, the Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG®), and Energy Information Administration (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. 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, operating and maintenance costs (O&M), 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 in both the with CO_2 and without CO_2 screening cases. The baseload curves also show that nuclear generation may be a cost effective option at high capacity factors with CO2 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 economical alternative than wind and landfill gas generation. Solar and wind projects are technically constrained from achieving high capacity factors making them unsuitable for intermediate or baseload duty cycles. Landfill gas projects are limited based on site availability but are dispatchable. 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. Results from the screening curve analysis provide guidance for the technologies to be further considered in the more detailed quantitative analysis phase of the planning process.

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C O N F I D E N T I A L

APPENDIX G: ENVIRONMENTAL COMPLIANCE

Legislative and Regulatory Issues

Duke Energy Carolinas, which is subject to the jurisdiction of Federal agencies including the Federal Energy Regulatory Commission (FERC), EPA, and the NRC, as well as State commissions and agencies, is potentially impacted by State and Federal legislative and regulatory actions. This section provides a high-level description of several issues Duke Energy Carolinas is actively monitoring or engaged in that could potentially influence the 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 reduced SO_2 emissions by approximately 95% from 2000 to 2013. 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 chart below show the significant downward trend in both NO_x and SO_2 emissions through 2013 as a result of actions taken at DEC facilities.

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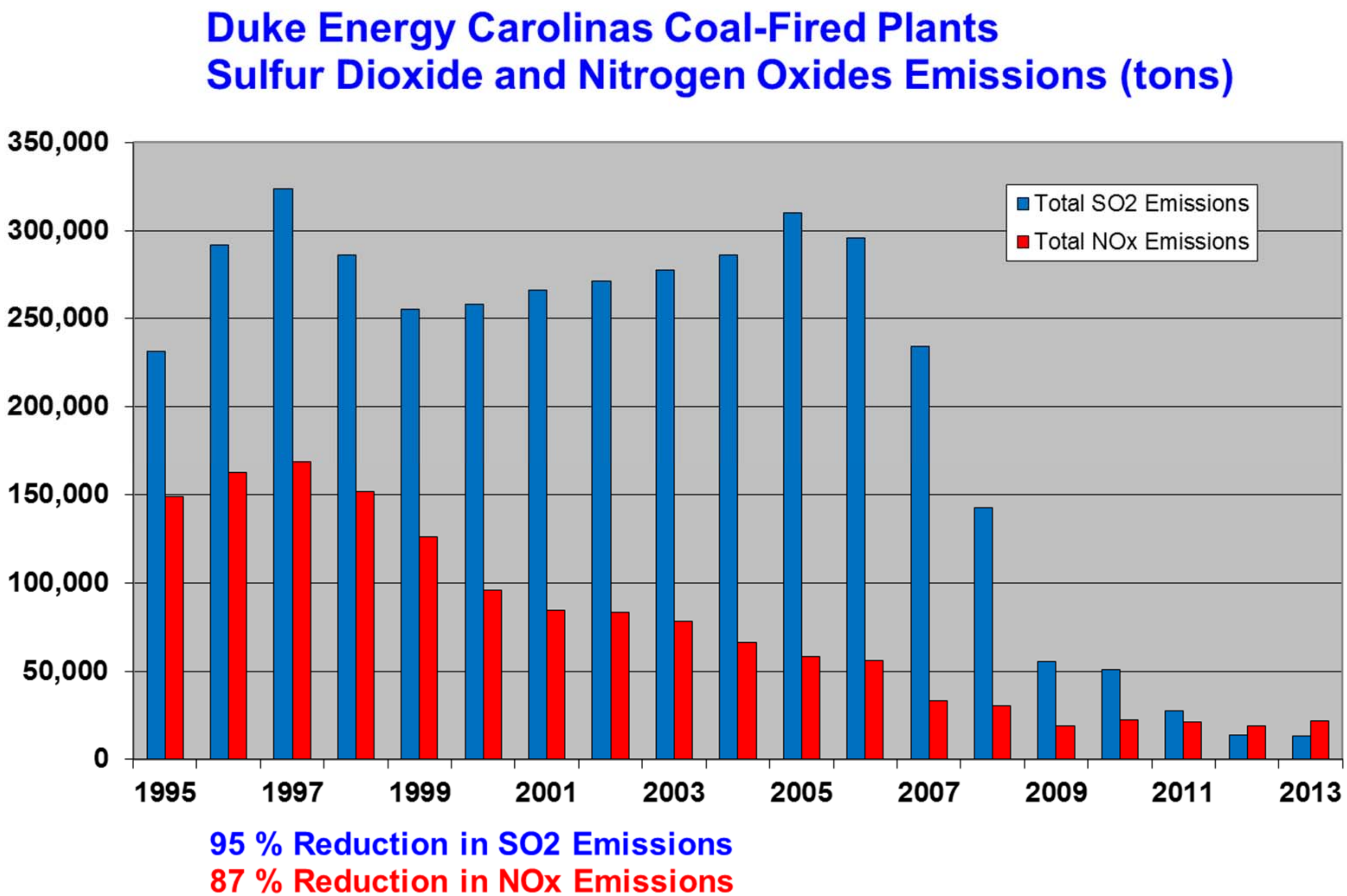
Chart G-1 DEC NO_x and SO_2 Emissions



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 its Clean Air Interstate Rule (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 ("D.C. Circuit") issued a decision remanding CAIR to the EPA, allowing CAIR to remain in effect until EPA developed a replacement regulation.

In August 2011, a replacement for CAIR was finalized as the Cross-State Air Pollution Rule (CSAPR). Scheduled to take effect on January 1, 2012, implementation of the CSAPR was stayed by the D.C. Circuit on December 30, 2011. Numerous petitions for review of the CSAPR were filed with the D.C. Circuit. On August 21, 2012, by a 2-1 decision, the D.C. Circuit vacated the CSAPR. The D.C. Circuit 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 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, and on April 29, 2014, the Supreme Court reversed the D.C. Circuit's decision, finding that with CSAPR, the EPA reasonably interpreted the good neighbor provision of the Clean Air Act. The case has been remanded to the D.C. Circuit for further proceedings consistent with the Supreme Court's opinion. As part of those proceedings, the EPA has requested that the D.C. Circuit lift the CSAPR stay and direct that Phase 1 of the rule take effect on January 1, 2015. The court has yet to rule on the EPA request. Meanwhile, the CAIR remains in effect, with Phase II set to take effect January 1, 2015.

While Duke Energy Carolinas cannot predict the outcome of the review process or how it could affect future emission reduction requirements, 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 reinstated, 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. The 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 by April 16, 2015. DEC has not requested compliance extensions for any of its affected facilities.

Numerous petitions for review challenging the final MATS rule were filed with the D.C. Circuit. In April 2014, the D.C. Circuit ruled in favor of EPA regarding all petitions, several parties to the litigation have subsequently petitioned the Supreme Court to review the D.C. Circuit's decision. Duke Energy Carolinas cannot predict the outcome of the litigation or how it might affect the MATS requirements as they apply to operations, Duke Energy Carolinas is planning for the rule to be implemented as promulgated.

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 more non-scrubbed coal-fired generating units in the Carolinas by June 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 North Carolina Clean Smokestacks Act.

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. The EPA is expected to propose a revised ozone standard in December 2014 and finalize a revised standard by October 2015.

On May 21, 2012, EPA finalized area designations for the 75 ppb 8-hour ozone standard finalized in 2008. Mecklenburg County and parts of surrounding counties were designated as a marginal nonattainment area with a 2015 attainment date. There are no specific actions currently being required in response to this designation.

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 a limited number of area designations in July 2013. No areas in the Carolinas were designated nonattainment.

In May 2014, the EPA issued a proposed Data Requirements Rule that included a proposed strategy and schedule for addressing the attainment status of areas not designated as nonattainment in July 2013. The proposal included a schedule for proposing and finalizing area designations and for states with nonattainment areas as a result of the designations process to submit State Implementation Plans to EPA.

In June 2014, the EPA requested comments on a proposed consent decree with the Sierra Club and the Natural Resources Defense Council related to the implementation of the 2010 75 ppb SO_2 standard. The proposed consent decree included provisions for addressing the attainment status of areas surrounding certain coal-fired power plants in the country on a more accelerated schedule that EPA proposed in its Data Requirement proposed rule. None of the Duke Energy Carolinas coal-fired power plants would be impacted by the accelerated designation schedule contained in the proposed consent decree.

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. The State of North Carolina has recommended to EPA that all areas in the State at the Township level be designated attainment.

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 requirements of 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

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 requires a Best Available Control Technology (BACT) analysis and the application of BACT for GHGs. BACT is 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 June 13, 2014, the Supreme Court issued a decision vacating EPA's Tailoring Rule and remanded the case to the D.C. Circuit for further proceedings. Duke Energy Carolinas cannot predict the outcome of the proceedings.

On January 8, 2014, the EPA proposed a rule to establish carbon dioxide (CO_2) new source performance standards (NSPS) for new electric utility steam generating units (EGUs). The proposal applies only to new pulverized coal (PC), integrated gasification combined cycle (IGCC) and natural gas combined cycle (NGCC) units that initiate construction after January 8, 2014. The EPA proposed a CO_2 emission standard of 1,100 lb CO_2/gross MWh of electricity generation for new PC and IGCC units, and 1,000 lb CO_2/gross MWh for new NGCC units. PC and IGCC units can only be achieved with carbon capture and sequestration (CCS) technology to meet the proposed emission limits. For numerous reasons, Duke Energy Carolinas views the EPA proposal as barring the development of new coal-fired generation because CCS is not a demonstrated and available technology for applying to EGUs. The requirements of the EPA proposal were effective upon proposal, but could be modified in a final rule. The Lee NGCC facility will be subject to the NSPS if the rule is finalized as proposed, but these units are expected to meet the proposed standard with no additional requirements. Duke Energy Carolinas cannot predict the outcome of this rulemaking.

On June 18, 2014, the EPA proposed the Clean Power Plan, a rule to limit CO_2 emissions from existing coal-fired power plants. The EPA has proposed a CO_2/MWh emission-rate goal for each state to take effect in 2030, and interim, less stringent state-specific goals that apply over the period 2020-2029. The 2030 goal EPA has proposed for North Carolina is 992 lbs CO_2/MWh; the goal for South Carolina is 772 lbs CO_2/MWh. The EPA is expected to finalize its rule by June 1, 2015. EPA has proposed that states submit their regulatory plans for implementing the EPA emission goals between June 30, 2016 and June 30, 2018. Duke Energy Carolinas cannot predict the outcome of EPA's rulemaking, or the approach that North Carolina might take in developing its regulations. Therefore, Duke Energy Carolinas cannot estimate the impact of the rule on its operations. Any final EPA rule will be challenged in court, which adds to the uncertainty of any future regulatory requirements.

There is no expectation that Congress will pass legislation mandating reductions in GHG emissions or establishing a carbon tax through 2014. 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 implementing §316(b) of the Clean Water Act (CWA) for existing facilities were signed on May 19, 2014. The rule was published in the Federal Register on August 15, 2014 with an effective date of October 14, 2014. The rule will be effective 60-days after publication in the Federal Register. The rule regulates cooling water intake structures at existing facilities to address environmental impacts from fish being impinged (pinned against cooling water intake structures) and entrained (being drawn into cooling water systems and affected by heat, chemicals or physical stress). The final rule establishes aquatic protection requirements at existing facilities and new on-site generation that withdraw 2 million gallons per day (MGD) or more from rivers, streams, lakes, reservoirs, estuaries, oceans, or other United States waters. All Duke Energy nuclear fueled, coal-fired and combined cycle stations, in North Carolina and South Carolina are affected sources, with the exception of Smith Energy [8].

The rule establishes two standards, one for impingement and one for entrainment. To demonstrate compliance with the impingement standard, facilities must choose and implement one of the following options:

— Closed cycle re-circulating cooling system; or

— Demonstrate the maximum design through screen velocity is less than 0.5 feet per second (fps) under all conditions; or

[8] Richmond County supplies cooling water to Smith Energy; therefore the rule is not applicable.

- Demonstrate the actual through screen velocity, based on measurement, is less than 0.5 feet per second (fps); or
- Install modified traveling water screens and optimize performance through a two-year study; or
- Demonstrate a system of technologies, practices, and operational measures are optimized to reduce impingement mortality comparable results to the impingement mortality limit; or
- Demonstrate that impingement latent mortality is reduced to no more than 24% annually based on monthly monitoring.

In addition to these options, the final rule allows the state permitting agency to establish less stringent standards if the capacity utilization rate is less than 8% averaged over a 24-month contiguous period. The rule, also, allows the state permitting agency to determine no further action warranted if impingement is considered *de minimis*. Compliance with the impingement standard is not required until requirements for entrainment are established.

The entrainment standard does not mandate the installation of a technology but rather establishes a process for the state permitting agency to determine necessary controls, if any, are required to reduce entrainment mortality on a site-specific basis. Facilities that withdraw more than 125 MGD are required to submit information to characterize the entrainment and assess the engineering feasibility, costs, and benefits of closed-cycle cooling, fine mesh screens and other technological and operational controls. The state permitting agency can determine no further action is required, or require the installation of fine mesh screens, or conversion to closed-cycle cooling.

The rule requires facilities with a NPDES permit that expire after July 14, 2018 to submit all necessary 316(b) reports with the renewal application. For facilities with a NPDES permit that expire prior to July 14, 2018 or are in the renewal process, the state permitting agency is allowed to establish an alternate submittal schedule. We expect submittals to be due in the 2018 to 2020 timeframe and intake modification, if necessary to be required in the 2019 to 2022 timeframe, depending on the NPDES permit renewal date and compliance schedule developed by the state permitting agency.

Steam Electric Effluent Guidelines

Proposed revisions to the Steam Electric Effluent Limitations Guidelines (ELGs) were published in the Federal Register on June 7, 2013. The revisions will affect a station's wastewater discharge permit by establishing technology based permit limits based on the performance of the best technology available selected by EPA. The rule was scheduled to be finalized on May 22, 2014; however, on April 7, 2014, EPA and the Defenders of Wildlife and Sierra Club signed an amended consent decree to extend the deadline to finalize the guidelines by September 30, 2015. The EPA proposed eight different regulatory options for the rule, of which four are listed as preferred. 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 facilities. The rule will be implemented through the National Pollutant Discharge Elimination System (NPDES) permit renewals. Portions of the rule regulating nonchemical metal cleaning and coal combustion residual leachate would be implemented immediately after the effective date of the rule upon the renewal of discharge permits. For other waste streams, such as wastewater from air pollution control equipment and ash handling, the rule is expected to allow a 3-year period for the station to install the appropriate technology prior to the limits being incorporated in the discharge permit. EPA expects that all facilities will be in compliance with the rule within 8 years of the effective date. The deadline to comply will depend upon each station's permit renewal schedule and the compliance schedule established by the permitting agency.

Coal Combustion Residuals

In January 2009, following Tennessee Valley Authority's (TVA) Kingston ash pond dike failure December 2008, Congress issued a mandate to EPA to develop Federal regulations for the disposal of coal combustion residuals (CCR). CCR includes fly ash, bottom ash, and flue gas desulfurization solids. In the interim, EPA conducted structural integrity inspections of all the surface impoundments nationwide that were used for disposal of CCR. In June 2010, EPA published its proposed rule for the disposal of CCR. The proposed rule offers two regulatory program 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, both programs included requirements for dam safety and integrity standards. Both options would require strict new requirements regarding the handling, disposal and potential re-use ability of CCR. The final rule will force dry handling of fly ash and bottom ash and the need for additional landfill capacity resulting from the closure of existing surface impoundments used manage CCR. This will also result in a need for alternative wastewater treatment capacity with smaller lined ponds to manage the other process wastewaters that were treated in the surface impoundments used to manage CCR. Final regulations are expected to be issued by EPA in December of 2014 or later. EPA's regulatory classification of CCR as hazardous or non-hazardous will be critical in developing plans for managing the disposal of CCR. However, under either option of the proposed rule, the impact to Duke Energy Progress is likely to be significant. Based on a 2014 final rule date, compliance with new regulations will begin immediately and with full compliance with all aspects of the rule 5 years later in 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 CONFIDENTIAL

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

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Table H-3 Non-Utility Generation – North Carolina

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
			North Carolina Generators:			
Facility 1	Fletcher	NC	Biogas	400.00	Baseload	Yes
Facility 2	Gerton	NC	Hydroelectric	6.00	Baseload	Yes
Facility 3	Lexington	NC	Other	1,193.60	Intermediate/Peaking	Yes
Facility 4	Charlotte	NC	Other	-	Intermediate/Peaking	Yes
Facility 5	Concord	NC	Other	596.80	Intermediate/Peaking	Yes
Facility 6	Mooresville	NC	Other	-	Intermediate/Peaking	Yes
Facility 7	Mills River	NC	Other	6.00	Intermediate/Peaking	Yes
Facility 8	Hendersonville	NC	Solar	10.25	Intermediate/Peaking	Yes
Facility 9	Randleman	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 10	Charlotte	NC	Solar	170.00	Intermediate/Peaking	Yes
Facility 11	Charlotte	NC	Solar	30.00	Intermediate/Peaking	Yes
Facility 12	Chapel Hill	NC	Solar	7.10	Intermediate/Peaking	Yes
Facility 13	Graham	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 14	Black Mountain	NC	Solar	3.42	Intermediate/Peaking	Yes
Facility 15	Wilkesboro	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 16	Shelby	NC	Solar	1.72	Intermediate/Peaking	Yes
Facility 17	Charlotte	NC	Solar	3.50	Intermediate/Peaking	Yes
Facility 18	Hendersonville	NC	Solar	2.10	Intermediate/Peaking	Yes
Facility 19	SUMMERFIELD	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 20	Charlotte	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 21	Charlotte	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 22	Wilkesboro	NC	Solar	7.50	Intermediate/Peaking	Yes
Facility 23	Bessemer City	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 24	Cornelius	NC	Solar	5.25	Intermediate/Peaking	Yes
Facility 25	COLUMBUS	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 26	Durham	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 27	Greensboro	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 28	Gastonia	NC	Solar	6.09	Intermediate/Peaking	Yes
Facility 29	Durham	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 30	Durham	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 31	Mooresville	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 32	Mooresville	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 33	Chapel Hill	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 34	Mebane	NC	Solar	4.52	Intermediate/Peaking	Yes
Facility 35	Chapel Hill	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 36	Durham	NC	Solar	5.75	Intermediate/Peaking	Yes
Facility 37	Davidson	NC	Solar	1.90	Intermediate/Peaking	Yes
Facility 38	Archdale	NC	Solar	28.80	Intermediate/Peaking	Yes
Facility 39	Burlington	NC	Solar	30.00	Intermediate/Peaking	Yes
Facility 40	Charlotte	NC	Solar	30.00	Intermediate/Peaking	Yes
Facility 41	Durham	NC	Solar	3.25	Intermediate/Peaking	Yes
Facility 42	Durham	NC	Solar	2.21	Intermediate/Peaking	Yes
Facility 43	MADISON	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 44	Charlotte	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 45	Hickory	NC	Solar	4.77	Intermediate/Peaking	Yes
Facility 46	Hickory	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 47	Brevard	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 48	Elon	NC	Solar	20.43	Intermediate/Peaking	Yes
Facility 49	Elon	NC	Solar	40.85	Intermediate/Peaking	Yes
Facility 50	Burlington	NC	Solar	0.74	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 51	Durham	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 52	Mooresville	NC	Solar	4.80	Intermediate/Peaking	Yes
Facility 53	Mount Pleasant	NC	Solar	6.08	Intermediate/Peaking	Yes
Facility 54	Charlotte	NC	Solar	2.45	Intermediate/Peaking	Yes
Facility 55	Greensboro	NC	Solar	4.62	Intermediate/Peaking	Yes
Facility 56	Thomasville	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 57	Durham	NC	Solar	3.78	Intermediate/Peaking	Yes
Facility 58	Durham	NC	Solar	3.87	Intermediate/Peaking	Yes
Facility 59	Greensboro	NC	Solar	3.50	Intermediate/Peaking	Yes
Facility 60	Glenville	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 61	Durham	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 62	Durham	NC	Solar	6.45	Intermediate/Peaking	Yes
Facility 63	Elkin	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 64	Carrboro	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 65	Kernersville	NC	Solar	0.74	Intermediate/Peaking	Yes
Facility 66	Charlotte	NC	Solar	1.85	Intermediate/Peaking	Yes
Facility 67	Elon	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 68	Cedar Grove	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 69	Kings Mountain	NC	Solar	15.00	Intermediate/Peaking	Yes
Facility 70	Cherokee	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 71	Salisbury	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 72	Sandy Ridge	NC	Solar	4.94	Intermediate/Peaking	Yes
Facility 73	Chapel Hill	NC	Solar	4.18	Intermediate/Peaking	Yes
Facility 74	Charlotte	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 75	Kings Mountain	NC	Solar	7.50	Intermediate/Peaking	Yes
Facility 76	Harrisburg	NC	Solar	0.86	Intermediate/Peaking	Yes
Facility 77	Moravian Falls	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 78	Hillsborough	NC	Solar	8.00	Intermediate/Peaking	Yes
Facility 79	Matthews	NC	Solar	2.63	Intermediate/Peaking	Yes
Facility 80	Waxhaw	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 81	Charlotte	NC	Solar	260.82	Intermediate/Peaking	Yes
Facility 82	Charlotte	NC	Solar	100.00	Intermediate/Peaking	Yes
Facility 83	Charlotte	NC	Solar	8.00	Intermediate/Peaking	Yes
Facility 84	Greensboro	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 85	Shelby	NC	Solar	0.86	Intermediate/Peaking	Yes
Facility 86	Durham	NC	Solar	30.00	Intermediate/Peaking	Yes
Facility 87	Wilkesboro	NC	Solar	1.92	Intermediate/Peaking	Yes
Facility 88	Hendersonville	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 89	Salisbury	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 90	Chapel Hill	NC	Solar	3.01	Intermediate/Peaking	Yes
Facility 91	Winston Salem	NC	Solar	2.82	Intermediate/Peaking	Yes
Facility 92	Winston Salem	NC	Solar	27.00	Intermediate/Peaking	Yes
Facility 93	China Grove	NC	Solar	5.76	Intermediate/Peaking	Yes
Facility 94	Burlington	NC	Solar	1.00	Intermediate/Peaking	Yes
Facility 95	Clemmons	NC	Solar	2.38	Intermediate/Peaking	Yes
Facility 96	Charlotte	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 97	Raleigh	NC	Solar	7.60	Intermediate/Peaking	Yes
Facility 98	Chapel Hill	NC	Solar	6.08	Intermediate/Peaking	Yes
Facility 99	Kernersville	NC	Solar	1.72	Intermediate/Peaking	Yes
Facility 100	Durham	NC	Solar	3.44	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 101	Durham	NC	Solar	2.28	Intermediate/Peaking	Yes
Facility 102	Catawba	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 103	Mills River	NC	Solar	4.94	Intermediate/Peaking	Yes
Facility 104	Stanley	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 105	Durham	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 106	Hillsborough	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 107	WESTFIELD	NC	Solar	1.44	Intermediate/Peaking	Yes
Facility 108	Statesville	NC	Solar	4.58	Intermediate/Peaking	Yes
Facility 109	Pisgah Forest	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 110	Charlotte	NC	Solar	4.50	Intermediate/Peaking	Yes
Facility 111	China Grove	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 112	Charlotte	NC	Solar	1.12	Intermediate/Peaking	Yes
Facility 113	Shelby	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 114	Penrose	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 115	Clemmons	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 116	Tobaccoville	NC	Solar	0.86	Intermediate/Peaking	Yes
Facility 117	Lawndale	NC	Solar	2.28	Intermediate/Peaking	Yes
Facility 118	Greensboro	NC	Solar	4.73	Intermediate/Peaking	Yes
Facility 119	Chapel Hill	NC	Solar	7.60	Intermediate/Peaking	Yes
Facility 120	Claremont	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 121	Charlotte	NC	Solar	0.70	Intermediate/Peaking	Yes
Facility 122	China Grove	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 123	Matthews	NC	Solar	3.50	Intermediate/Peaking	Yes
Facility 124	Hendersonville	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 125	Chapel Hill	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 126	Davidson	NC	Solar	94.08	Intermediate/Peaking	Yes
Facility 127	Lewisville	NC	Solar	0.70	Intermediate/Peaking	Yes
Facility 128	Winston Salem	NC	Solar	3.50	Intermediate/Peaking	Yes
Facility 129	Durham	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 130	Whittier	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 131	Hickory	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 132	Greensboro	NC	Solar	6.72	Intermediate/Peaking	Yes
Facility 133	Kannapolis	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 134	Mooresville	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 135	Durham	NC	Solar	101.20	Intermediate/Peaking	Yes
Facility 136	Whittier	NC	Solar	4.41	Intermediate/Peaking	Yes
Facility 137	Moravian Falls	NC	Solar	2.76	Intermediate/Peaking	Yes
Facility 138	Charlotte	NC	Solar	2.15	Intermediate/Peaking	Yes
Facility 139	Greensboro	NC	Solar	36.00	Intermediate/Peaking	Yes
Facility 140	Charlotte	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 141	Durham	NC	Solar	4.77	Intermediate/Peaking	Yes
Facility 142	Salisbury	NC	Solar	2.70	Intermediate/Peaking	Yes
Facility 143	SUMMERFIELD	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 144	Charlotte	NC	Solar	2.65	Intermediate/Peaking	Yes
Facility 145	Mooresville	NC	Solar	6.02	Intermediate/Peaking	Yes
Facility 146	FRANKLIN	NC	Solar	4.50	Intermediate/Peaking	Yes
Facility 147	Taylorsville	NC	Solar	0.70	Intermediate/Peaking	Yes
Facility 148	Chapel Hill	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 149	Chapel Hill	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 150	Pfafftown	NC	Solar	3.87	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 151	Reidsville	NC	Solar	1.60	Intermediate/Peaking	Yes
Facility 152	Morganton	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 153	Sherrills Ford	NC	Solar	6.06	Intermediate/Peaking	Yes
Facility 154	COLUMBUS	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 155	Burlington	NC	Solar	11.88	Intermediate/Peaking	Yes
Facility 156	Reidsville	NC	Solar	3.87	Intermediate/Peaking	Yes
Facility 157	Gibsonville	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 158	Charlotte	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 159	Durham	NC	Solar	40.00	Intermediate/Peaking	Yes
Facility 160	Hillsborough	NC	Solar	10.68	Intermediate/Peaking	Yes
Facility 161	Old Fort	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 162	Cherokee	NC	Solar	13.72	Intermediate/Peaking	Yes
Facility 163	Cherokee	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 164	FRANKLIN	NC	Solar	8.60	Intermediate/Peaking	Yes
Facility 165	Charlotte	NC	Solar	4.58	Intermediate/Peaking	Yes
Facility 166	Charlotte	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 167	Chapel Hill	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 168	Charltote	NC	Solar	4.58	Intermediate/Peaking	Yes
Facility 169	Marion	NC	Solar	18.00	Intermediate/Peaking	Yes
Facility 170	Lenoir	NC	Solar	1.40	Intermediate/Peaking	Yes
Facility 171	Durham	NC	Solar	75.00	Intermediate/Peaking	Yes
Facility 172	Durham	NC	Solar	30.00	Intermediate/Peaking	Yes
Facility 173	Durham	NC	Solar	50.00	Intermediate/Peaking	Yes
Facility 174	Durham	NC	Solar	52.90	Intermediate/Peaking	Yes
Facility 175	Durham	NC	Solar	2.16	Intermediate/Peaking	Yes
Facility 176	Raleigh	NC	Solar	2.82	Intermediate/Peaking	Yes
Facility 177	Hendersonville	NC	Solar	4.90	Intermediate/Peaking	Yes
Facility 178	Charlotte	NC	Solar	2.85	Intermediate/Peaking	Yes
Facility 179	Charlotte	NC	Solar	9.03	Intermediate/Peaking	Yes
Facility 180	Greensboro	NC	Solar	14.40	Intermediate/Peaking	Yes
Facility 181	Clemmons	NC	Solar	2.38	Intermediate/Peaking	Yes
Facility 182	Clemmons	NC	Solar	2.30	Intermediate/Peaking	Yes
Facility 183	Chapel Hill	NC	Solar	5.59	Intermediate/Peaking	Yes
Facility 184	Charlotte	NC	Solar	11.77	Intermediate/Peaking	Yes
Facility 185	Mebane	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 186	Chapel Hill	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 187	Hendersonville	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 188	Greensboro	NC	Solar	1.75	Intermediate/Peaking	Yes
Facility 189	Pisgah Forest	NC	Solar	4.38	Intermediate/Peaking	Yes
Facility 190	Whittier	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 191	Mooresville	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 192	Browns Summit	NC	Solar	2.16	Intermediate/Peaking	Yes
Facility 193	Durham	NC	Solar	700.00	Intermediate/Peaking	Yes
Facility 194	SUMMERFIELD	NC	Solar	0.86	Intermediate/Peaking	Yes
Facility 195	Nebo	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 196	Hendersonville	NC	Solar	2.82	Intermediate/Peaking	Yes
Facility 197	Davidson	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 198	Rural Hall	NC	Solar	4.50	Intermediate/Peaking	Yes
Facility 199	COLUMBUS	NC	Solar	2.14	Intermediate/Peaking	Yes
Facility 200	Charlotte	NC	Solar	1.96	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 201	Durham	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 202	Millers Creek	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 203	Marion	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 204	Chapel Hill	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 205	Chapel Hill	NC	Solar	1.64	Intermediate/Peaking	Yes
Facility 206	Durham	NC	Solar	307.43	Intermediate/Peaking	Yes
Facility 207	Hickory	NC	Solar	1.40	Intermediate/Peaking	Yes
Facility 208	Charlotte	NC	Solar	1.72	Intermediate/Peaking	Yes
Facility 209	Mills River	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 210	COLUMBUS	NC	Solar	2.15	Intermediate/Peaking	Yes
Facility 211	COLUMBUS	NC	Solar	12.04	Intermediate/Peaking	Yes
Facility 212	FRANKLIN	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 213	Denver	NC	Solar	0.70	Intermediate/Peaking	Yes
Facility 214	Chapel Hill	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 215	Winston Salem	NC	Solar	2.86	Intermediate/Peaking	Yes
Facility 216	Kannapolis	NC	Solar	3.01	Intermediate/Peaking	Yes
Facility 217	Clemmons	NC	Solar	8.00	Intermediate/Peaking	Yes
Facility 218	Ellenboro	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 219	Kernersville	NC	Solar	40.00	Intermediate/Peaking	Yes
Facility 220	Winston Salem	NC	Solar	14.80	Intermediate/Peaking	Yes
Facility 221	Whitsett	NC	Solar	7.50	Intermediate/Peaking	Yes
Facility 222	Concord	NC	Solar	5.20	Intermediate/Peaking	Yes
Facility 223	Durham	NC	Solar	3.01	Intermediate/Peaking	Yes
Facility 224	Chapel Hill	NC	Solar	3.30	Intermediate/Peaking	Yes
Facility 225	Chapel Hill	NC	Solar	7.00	Intermediate/Peaking	Yes
Facility 226	Charlotte	NC	Solar	2.15	Intermediate/Peaking	Yes
Facility 227	Thomasville	NC	Solar	1.29	Intermediate/Peaking	Yes
Facility 228	Haw River	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 229	Lincolnton	NC	Solar	2.15	Intermediate/Peaking	Yes
Facility 230	Cedar Grove	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 231	Charlotte	NC	Solar	790.00	Intermediate/Peaking	Yes
Facility 232	Salisbury	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 233	Pfafftown	NC	Solar	4.72	Intermediate/Peaking	Yes
Facility 234	Charlotte	NC	Solar	2.85	Intermediate/Peaking	Yes
Facility 235	Greensboro	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 236	Chapel Hill	NC	Solar	9.17	Intermediate/Peaking	Yes
Facility 237	Charlotte	NC	Solar	1.08	Intermediate/Peaking	Yes
Facility 238	Charlotte	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 239	Charlotte	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 240	Saluda	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 241	Hickory	NC	Solar	3.01	Intermediate/Peaking	Yes
Facility 242	Rockwell	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 243	Greensboro	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 244	Germanton	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 245	Winston Salem	NC	Solar	2.86	Intermediate/Peaking	Yes
Facility 246	Durham	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 247	Charlotte	NC	Solar	1.75	Intermediate/Peaking	Yes
Facility 248	MONROE	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 249	King	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 250	Saluda	NC	Solar	6.65	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 251	Kannapolis	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 252	Mebane	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 253	Liberty	NC	Solar	4.90	Intermediate/Peaking	Yes
Facility 254	Concord	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 255	Durham	NC	Solar	2.21	Intermediate/Peaking	Yes
Facility 256	Charlotte	NC	Solar	1.40	Intermediate/Peaking	Yes
Facility 257	Salisbury	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 258	Durham	NC	Solar	3.84	Intermediate/Peaking	Yes
Facility 259	Reidsville	NC	Solar	0.76	Intermediate/Peaking	Yes
Facility 260	Cullowhee	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 261	Union Mills	NC	Solar	4.18	Intermediate/Peaking	Yes
Facility 262	Durham	NC	Solar	2.21	Intermediate/Peaking	Yes
Facility 263	Mooresville	NC	Solar	7.96	Intermediate/Peaking	Yes
Facility 264	Cornelius	NC	Solar	6.02	Intermediate/Peaking	Yes
Facility 265	Pisgah Forest	NC	Solar	0.70	Intermediate/Peaking	Yes
Facility 266	Chapel Hill	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 267	Durham	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 268	Chapel Hill	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 269	Durham	NC	Solar	2.48	Intermediate/Peaking	Yes
Facility 270	Durham	NC	Solar	1.25	Intermediate/Peaking	Yes
Facility 271	Greensboro	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 272	Lenoir	NC	Solar	7.95	Intermediate/Peaking	Yes
Facility 273	Durham	NC	Solar	3.23	Intermediate/Peaking	Yes
Facility 274	Durham	NC	Solar	6.45	Intermediate/Peaking	Yes
Facility 275	Charlotte	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 276	Terrell	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 277	Graham	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 278	McLeansville	NC	Solar	2.86	Intermediate/Peaking	Yes
Facility 279	Cullowhee	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 280	Greensboro	NC	Solar	2.15	Intermediate/Peaking	Yes
Facility 281	Concord	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 282	Granite Falls	NC	Solar	6.45	Intermediate/Peaking	Yes
Facility 283	Durham	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 284	Maiden	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 285	Burlington	NC	Solar	3.24	Intermediate/Peaking	Yes
Facility 286	Greensboro	NC	Solar	2.38	Intermediate/Peaking	Yes
Facility 287	Old Fort	NC	Solar	3.01	Intermediate/Peaking	Yes
Facility 288	Marble	NC	Solar	7.60	Intermediate/Peaking	Yes
Facility 289	Winston Salem	NC	Solar	3.99	Intermediate/Peaking	Yes
Facility 290	Durham	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 291	Charlotte	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 292	Hendersonville	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 293	Hillsborough	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 294	Durham	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 295	Charlotte	NC	Solar	3.04	Intermediate/Peaking	Yes
Facility 296	Durham	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 297	Gibsonville	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 298	Durham	NC	Solar	2.82	Intermediate/Peaking	Yes
Facility 299	Liberty	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 300	Greensboro	NC	Solar	2.00	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 301	Lewisville	NC	Solar	2.85	Intermediate/Peaking	Yes
Facility 302	Greensboro	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 303	Mills River	NC	Solar	6.45	Intermediate/Peaking	Yes
Facility 304	Rural Hall	NC	Solar	2.85	Intermediate/Peaking	Yes
Facility 305	Mills River	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 306	Chapel Hill	NC	Solar	7.80	Intermediate/Peaking	Yes
Facility 307	Saluda	NC	Solar	4.32	Intermediate/Peaking	Yes
Facility 308	Mills River	NC	Solar	7.31	Intermediate/Peaking	Yes
Facility 309	Waxhaw	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 310	Hendersonville	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 311	Salisbury	NC	Solar	8.80	Intermediate/Peaking	Yes
Facility 312	Mooresville	NC	Solar	3.30	Intermediate/Peaking	Yes
Facility 313	Tobaccoville	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 314	East Bend	NC	Solar	4.73	Intermediate/Peaking	Yes
Facility 315	Durham	NC	Solar	5.94	Intermediate/Peaking	Yes
Facility 316	Durham	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 317	Gold Hill	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 318	Mooresville	NC	Solar	250.00	Intermediate/Peaking	Yes
Facility 319	N Wilkesboro	NC	Solar	4.73	Intermediate/Peaking	Yes
Facility 320	Greensboro	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 321	Durham	NC	Solar	4.77	Intermediate/Peaking	Yes
Facility 322	Catawba	NC	Solar	15.20	Intermediate/Peaking	Yes
Facility 323	Catawba	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 324	Durham	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 325	Marion	NC	Solar	0.76	Intermediate/Peaking	Yes
Facility 326	Robbinsville	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 327	Kernersville	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 328	Forest City	NC	Solar	0.86	Intermediate/Peaking	Yes
Facility 329	Germanton	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 330	Charlotte	NC	Solar	4.20	Intermediate/Peaking	Yes
Facility 331	Chapel Hill	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 332	Brevard	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 333	Chapel Hill	NC	Solar	1.20	Intermediate/Peaking	Yes
Facility 334	Charlotte	NC	Solar	3.01	Intermediate/Peaking	Yes
Facility 335	Hendersonville	NC	Solar	2.28	Intermediate/Peaking	Yes
Facility 336	Reidsville	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 337	Chapel Hill	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 338	Old Fort	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 339	King	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 340	Durham	NC	Solar	3.25	Intermediate/Peaking	Yes
Facility 341	Hendersonville	NC	Solar	0.76	Intermediate/Peaking	Yes
Facility 342	Lewisville	NC	Solar	2.35	Intermediate/Peaking	Yes
Facility 343	Ronda	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 344	Tobaccoville	NC	Solar	9.80	Intermediate/Peaking	Yes
Facility 345	FRANKLIN	NC	Solar	1.44	Intermediate/Peaking	Yes
Facility 346	Dobson	NC	Solar	7.95	Intermediate/Peaking	Yes
Facility 347	Brevard	NC	Solar	3.80	Intermediate/Peaking	Yes
Facility 348	Greensboro	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 349	Mount Airy	NC	Solar	4.60	Intermediate/Peaking	Yes
Facility 350	Chapel Hill	NC	Solar	13.33	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 351	Hickory	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 352	Andrews	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 353	Lewisville	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 354	Andrews	NC	Solar	3.01	Intermediate/Peaking	Yes
Facility 355	Marion	NC	Solar	3.57	Intermediate/Peaking	Yes
Facility 356	Valdese	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 357	High Point	NC	Solar	2.38	Intermediate/Peaking	Yes
Facility 358	Durham	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 359	Mount Pleasant	NC	Solar	4.50	Intermediate/Peaking	Yes
Facility 360	Greensboro	NC	Solar	3.68	Intermediate/Peaking	Yes
Facility 361	Durham	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 362	Pfafftown	NC	Solar	4.20	Intermediate/Peaking	Yes
Facility 363	Taylorsville	NC	Solar	1.94	Intermediate/Peaking	Yes
Facility 364	Raleigh	NC	Solar	6.87	Intermediate/Peaking	Yes
Facility 365	Tobaccoville	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 366	SUMMERFIELD	NC	Solar	4.91	Intermediate/Peaking	Yes
Facility 367	Charlotte	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 368	East Bend	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 369	Charlotte	NC	Solar	3.50	Intermediate/Peaking	Yes
Facility 370	Charlotte	NC	Solar	36.00	Intermediate/Peaking	Yes
Facility 371	Greensboro	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 372	Union Mills	NC	Solar	1.94	Intermediate/Peaking	Yes
Facility 373	Durham	NC	Solar	3.84	Intermediate/Peaking	Yes
Facility 374	Gerton	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 375	Clemmons	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 376	Kernersville	NC	Solar	6.02	Intermediate/Peaking	Yes
Facility 377	Kernersville	NC	Solar	6.02	Intermediate/Peaking	Yes
Facility 378	Kernersville	NC	Solar	6.02	Intermediate/Peaking	Yes
Facility 379	Kernersville	NC	Solar	6.02	Intermediate/Peaking	Yes
Facility 380	Kernersville	NC	Solar	3.87	Intermediate/Peaking	Yes
Facility 381	Durham	NC	Solar	2.15	Intermediate/Peaking	Yes
Facility 382	Huntersville	NC	Solar	4.91	Intermediate/Peaking	Yes
Facility 383	Chapel Hill	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 384	Chapel Hill	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 385	Hillsborough	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 386	Graham	NC	Solar	2.10	Intermediate/Peaking	Yes
Facility 387	Matthews	NC	Solar	6.75	Intermediate/Peaking	Yes
Facility 388	Chapel Hill	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 389	Chapel Hill	NC	Solar	5.56	Intermediate/Peaking	Yes
Facility 390	China Grove	NC	Solar	1.70	Intermediate/Peaking	Yes
Facility 391	Waxhaw	NC	Solar	2.94	Intermediate/Peaking	Yes
Facility 392	Advance	NC	Solar	7.85	Intermediate/Peaking	Yes
Facility 393	Chapel Hill	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 394	Saluda	NC	Solar	3.66	Intermediate/Peaking	Yes
Facility 395	Clemmons	NC	Solar	3.87	Intermediate/Peaking	Yes
Facility 396	Durham	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 397	Otto	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 398	Stokesdale	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 399	Salisbury	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 400	Salisbury	NC	Solar	12.00	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 401	Harrisburg	NC	Solar	6.66	Intermediate/Peaking	Yes
Facility 402	Lexington	NC	Solar	3.45	Intermediate/Peaking	Yes
Facility 403	Charlotte	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 404	Shelby	NC	Solar	4.70	Intermediate/Peaking	Yes
Facility 405	Davidson	NC	Solar	3.50	Intermediate/Peaking	Yes
Facility 406	Durham	NC	Solar	2.21	Intermediate/Peaking	Yes
Facility 407	Randleman	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 408	Clemmons	NC	Solar	8.00	Intermediate/Peaking	Yes
Facility 409	Winston Salem	NC	Solar	3.15	Intermediate/Peaking	Yes
Facility 410	FRANKLIN	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 411	Hendersonville	NC	Solar	2.70	Intermediate/Peaking	Yes
Facility 412	Clemmons	NC	Solar	7.31	Intermediate/Peaking	Yes
Facility 413	Durham	NC	Solar	2.21	Intermediate/Peaking	Yes
Facility 414	Charlotte	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 415	Concord	NC	Solar	5.83	Intermediate/Peaking	Yes
Facility 416	Morganton	NC	Solar	3.50	Intermediate/Peaking	Yes
Facility 417	Charlotte	NC	Solar	0.70	Intermediate/Peaking	Yes
Facility 418	Hickory	NC	Solar	8.17	Intermediate/Peaking	Yes
Facility 419	Charlotte	NC	Solar	49.00	Intermediate/Peaking	Yes
Facility 420	Charlotte	NC	Solar	12.00	Intermediate/Peaking	Yes
Facility 421	Union Mills	NC	Solar	1.96	Intermediate/Peaking	Yes
Facility 422	Winston Salem	NC	Solar	2.20	Intermediate/Peaking	Yes
Facility 423	Charlotte	NC	Solar	5.76	Intermediate/Peaking	Yes
Facility 424	Chapel Hill	NC	Solar	3.25	Intermediate/Peaking	Yes
Facility 425	Chapel Hill	NC	Solar	1.32	Intermediate/Peaking	Yes
Facility 426	Elon	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 427	Yadkinville	NC	Solar	7.10	Intermediate/Peaking	Yes
Facility 428	Glenville	NC	Solar	2.76	Intermediate/Peaking	Yes
Facility 429	Charlotte	NC	Solar	1.53	Intermediate/Peaking	Yes
Facility 430	Yadkinville	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 431	Charlotte	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 432	Union Mills	NC	Solar	1.94	Intermediate/Peaking	Yes
Facility 433	Charlotte	NC	Solar	4.91	Intermediate/Peaking	Yes
Facility 434	Mooresville	NC	Solar	2.80	Intermediate/Peaking	Yes
Facility 435	Lexington	NC	Solar	4.32	Intermediate/Peaking	Yes
Facility 436	Lake Lure	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 437	Durham	NC	Solar	3.23	Intermediate/Peaking	Yes
Facility 438	Durham	NC	Solar	2.35	Intermediate/Peaking	Yes
Facility 439	Durham	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 440	Brevard	NC	Solar	5.76	Intermediate/Peaking	Yes
Facility 441	Charlotte	NC	Solar	4.80	Intermediate/Peaking	Yes
Facility 442	Durham	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 443	Burlington	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 444	Charlotte	NC	Solar	35.00	Intermediate/Peaking	Yes
Facility 445	Charlotte	NC	Solar	30.00	Intermediate/Peaking	Yes
Facility 446	Research Triangle Park	NC	Solar	28.00	Intermediate/Peaking	Yes
Facility 447	Chapel Hill	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 448	Pisgah Forest	NC	Solar	4.73	Intermediate/Peaking	Yes
Facility 449	Wingate	NC	Solar	2.63	Intermediate/Peaking	Yes
Facility 450	Kannapolis	NC	Solar	10.00	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 451	Salisbury	NC	Solar	7.50	Intermediate/Peaking	Yes
Facility 452	Charlotte	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 453	Chapel Hill	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 454	Old Fort	NC	Solar	4.68	Intermediate/Peaking	Yes
Facility 455	McLeansville	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 456	Oak Ridge	NC	Solar	3.01	Intermediate/Peaking	Yes
Facility 457	FRANKLIN	NC	Solar	1.92	Intermediate/Peaking	Yes
Facility 458	Chapel Hill	NC	Solar	3.78	Intermediate/Peaking	Yes
Facility 459	Salisbury	NC	Solar	5.60	Intermediate/Peaking	Yes
Facility 460	Salisbury	NC	Solar	7.20	Intermediate/Peaking	Yes
Facility 461	Rockwell	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 462	Gibsonville	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 463	Jonesville	NC	Solar	3.93	Intermediate/Peaking	Yes
Facility 464	Durham	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 465	Denver	NC	Solar	9.18	Intermediate/Peaking	Yes
Facility 466	Greensboro	NC	Solar	2.70	Intermediate/Peaking	Yes
Facility 467	Burlington	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 468	Winston Salem	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 469	Butner	NC	Solar	5.10	Intermediate/Peaking	Yes
Facility 470	Durham	NC	Solar	3.36	Intermediate/Peaking	Yes
Facility 471	Ellenboro	NC	Solar	3.68	Intermediate/Peaking	Yes
Facility 472	Salisbury	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 473	Greensboro	NC	Solar	1.80	Intermediate/Peaking	Yes
Facility 474	Chapel Hill	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 475	Charlotte	NC	Solar	52.47	Intermediate/Peaking	Yes
Facility 476	Horse Shoe	NC	Solar	0.19	Intermediate/Peaking	Yes
Facility 477	Charlotte	NC	Solar	8.80	Intermediate/Peaking	Yes
Facility 478	Charlotte	NC	Solar	7.60	Intermediate/Peaking	Yes
Facility 479	SUMMERFIELD	NC	Solar	2.45	Intermediate/Peaking	Yes
Facility 480	Chapel Hill	NC	Solar	1.20	Intermediate/Peaking	Yes
Facility 481	Salisbury	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 482	Rutherfordton	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 483	Tryon	NC	Solar	5.18	Intermediate/Peaking	Yes
Facility 484	Durham	NC	Solar	1.20	Intermediate/Peaking	Yes
Facility 485	COLUMBUS	NC	Solar	1.72	Intermediate/Peaking	Yes
Facility 486	Charlotte	NC	Solar	18.06	Intermediate/Peaking	Yes
Facility 487	Chapel Hill	NC	Solar	7.00	Intermediate/Peaking	Yes
Facility 488	Hendersonville	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 489	Winston Salem	NC	Solar	1.94	Intermediate/Peaking	Yes
Facility 490	Hendersonville	NC	Solar	3.80	Intermediate/Peaking	Yes
Facility 491	Randleman	NC	Solar	2.30	Intermediate/Peaking	Yes
Facility 492	Mooresville	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 493	Pinnacle	NC	Solar	4.50	Intermediate/Peaking	Yes
Facility 494	Otto	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 495	Chapel Hill	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 496	Norwood	NC	Solar	5.17	Intermediate/Peaking	Yes
Facility 497	Charlotte	NC	Solar	3.45	Intermediate/Peaking	Yes
Facility 498	Winston Salem	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 499	Maiden	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 500	Moravian FLS	NC	Solar	3.68	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 501	Greensboro	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 502	Salisbury	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 503	Efland	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 504	Charlotte	NC	Solar	4.70	Intermediate/Peaking	Yes
Facility 505	Durham	NC	Solar	3.78	Intermediate/Peaking	Yes
Facility 506	Glenville	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 507	Greensboro	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 508	Waxhaw	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 509	Charlotte	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 510	Harrisburg	NC	Solar	3.23	Intermediate/Peaking	Yes
Facility 511	Chapel Hill	NC	Solar	3.50	Intermediate/Peaking	Yes
Facility 512	Julian	NC	Solar	1.10	Intermediate/Peaking	Yes
Facility 513	Winston Salem	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 514	Charlotte	NC	Solar	2.35	Intermediate/Peaking	Yes
Facility 515	Horse Shoe	NC	Solar	3.01	Intermediate/Peaking	Yes
Facility 516	FRANKLIN	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 517	Durham	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 518	Hendersonville	NC	Solar	0.76	Intermediate/Peaking	Yes
Facility 519	Indian Trail	NC	Solar	1.00	Intermediate/Peaking	Yes
Facility 520	Charlotte	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 521	Waxhaw	NC	Solar	9.48	Intermediate/Peaking	Yes
Facility 522	Hendersonville	NC	Solar	1.72	Intermediate/Peaking	Yes
Facility 523	FRANKLIN	NC	Solar	5.94	Intermediate/Peaking	Yes
Facility 524	Randleman	NC	Solar	4.80	Intermediate/Peaking	Yes
Facility 525	Salisbury	NC	Solar	6.45	Intermediate/Peaking	Yes
Facility 526	Pisgah Forest	NC	Solar	5.59	Intermediate/Peaking	Yes
Facility 527	Mooresville	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 528	Salisbury	NC	Solar	16.20	Intermediate/Peaking	Yes
Facility 529	Carrboro	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 530	Durham	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 531	Hendersonville	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 532	Mooresville	NC	Solar	2.94	Intermediate/Peaking	Yes
Facility 533	Charlotte	NC	Solar	4.91	Intermediate/Peaking	Yes
Facility 534	Gerton	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 535	Durham	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 536	Charlotte	NC	Solar	4.73	Intermediate/Peaking	Yes
Facility 537	Charlotte	NC	Solar	10.80	Intermediate/Peaking	Yes
Facility 538	Elon	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 539	Elon	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 540	Chapel Hill	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 541	Durham	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 542	Pelham	NC	Solar	2.82	Intermediate/Peaking	Yes
Facility 543	Pineville	NC	Solar	40.00	Intermediate/Peaking	Yes
Facility 544	Hillsborough	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 545	Greensboro	NC	Solar	5.46	Intermediate/Peaking	Yes
Facility 546	Conover	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 547	Chapel Hill	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 548	Durham	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 549	Chapel Hill	NC	Solar	7.60	Intermediate/Peaking	Yes
Facility 550	Marion	NC	Solar	1.02	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 551	Durham	NC	Solar	3.50	Intermediate/Peaking	Yes
Facility 552	Concord	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 553	Hendersonville	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 554	Taylorsville	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 555	Marion	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 556	Greensboro	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 557	Durham	NC	Solar	101.20	Intermediate/Peaking	Yes
Facility 558	Fletcher	NC	Solar	600.00	Intermediate/Peaking	Yes
Facility 559	Greensboro	NC	Solar	12.00	Intermediate/Peaking	Yes
Facility 560	Winston Salem	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 561	Cherryville	NC	Solar	6.40	Intermediate/Peaking	Yes
Facility 562	Durham	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 563	Elkin	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 564	Stanley	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 565	Durham	NC	Solar	3.66	Intermediate/Peaking	Yes
Facility 566	Durham	NC	Solar	2.04	Intermediate/Peaking	Yes
Facility 567	Morganton	NC	Solar	3.04	Intermediate/Peaking	Yes
Facility 568	Statesville	NC	Solar	1.51	Intermediate/Peaking	Yes
Facility 569	Durham	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 570	Durham	NC	Solar	3.87	Intermediate/Peaking	Yes
Facility 571	Durham	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 572	Whittier	NC	Solar	4.24	Intermediate/Peaking	Yes
Facility 573	Whittier	NC	Solar	0.43	Intermediate/Peaking	Yes
Facility 574	Reidsville	NC	Solar	4.73	Intermediate/Peaking	Yes
Facility 575	Hickory	NC	Solar	4.41	Intermediate/Peaking	Yes
Facility 576	Durham	NC	Solar	3.84	Intermediate/Peaking	Yes
Facility 577	Charlotte	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 578	Greensboro	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 579	Greensboro	NC	Solar	8.00	Intermediate/Peaking	Yes
Facility 580	Cedar Grove	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 581	Snow Camp	NC	Solar	2.85	Intermediate/Peaking	Yes
Facility 582	Chapel Hill	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 583	Brevard	NC	Solar	3.36	Intermediate/Peaking	Yes
Facility 584	Winston Salem	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 585	Charlotte	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 586	Charlotte	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 587	Pisgah Forest	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 588	Chapel Hill	NC	Solar	4.41	Intermediate/Peaking	Yes
Facility 589	Charlotte	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 590	Durham	NC	Solar	2.21	Intermediate/Peaking	Yes
Facility 591	Conover	NC	Solar	4.76	Intermediate/Peaking	Yes
Facility 592	Gastonia	NC	Solar	1.14	Intermediate/Peaking	Yes
Facility 593	Charlotte	NC	Solar	1.96	Intermediate/Peaking	Yes
Facility 594	Reidsville	NC	Solar	2.80	Intermediate/Peaking	Yes
Facility 595	Bryson City	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 596	Durham	NC	Solar	2.80	Intermediate/Peaking	Yes
Facility 597	Research Triangle Park	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 598	Lincolnton	NC	Solar	6.02	Intermediate/Peaking	Yes
Facility 599	Greensboro	NC	Solar	2.15	Intermediate/Peaking	Yes
Facility 600	Durham	NC	Solar	2.50	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 601	Claremont	NC	Solar	5.59	Intermediate/Peaking	Yes
Facility 602	Archdale	NC	Solar	20.00	Intermediate/Peaking	Yes
Facility 603	Archdale	NC	Solar	52.00	Intermediate/Peaking	Yes
Facility 604	Chapel Hill	NC	Solar	0.74	Intermediate/Peaking	Yes
Facility 605	Charlotte	NC	Solar	1.12	Intermediate/Peaking	Yes
Facility 606	Oak Ridge	NC	Solar	2.15	Intermediate/Peaking	Yes
Facility 607	Pfafftown	NC	Solar	1.72	Intermediate/Peaking	Yes
Facility 608	Durham	NC	Solar	13.77	Intermediate/Peaking	Yes
Facility 609	Charlotte	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 610	Charlotte	NC	Solar	3.51	Intermediate/Peaking	Yes
Facility 611	Charlotte	NC	Solar	4.60	Intermediate/Peaking	Yes
Facility 612	Hickory	NC	Solar	4.70	Intermediate/Peaking	Yes
Facility 613	COLUMBUS	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 614	Black Mountain	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 615	Durham	NC	Solar	4.58	Intermediate/Peaking	Yes
Facility 616	Charlotte	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 617	Hendersonville	NC	Solar	1.94	Intermediate/Peaking	Yes
Facility 618	Indian Trail	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 619	Stokesdale	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 620	Liberty	NC	Solar	3.98	Intermediate/Peaking	Yes
Facility 621	Concord	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 622	Charlotte	NC	Solar	7.50	Intermediate/Peaking	Yes
Facility 623	Bostic	NC	Solar	2.80	Intermediate/Peaking	Yes
Facility 624	Iron Station	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 625	Charlotte	NC	Solar	4.95	Intermediate/Peaking	Yes
Facility 626	Durham	NC	Solar	4.95	Intermediate/Peaking	Yes
Facility 627	Chapel Hill	NC	Solar	1.48	Intermediate/Peaking	Yes
Facility 628	Browns Summit	NC	Solar	3.01	Intermediate/Peaking	Yes
Facility 629	Charlotte	NC	Solar	3.29	Intermediate/Peaking	Yes
Facility 630	Morganton	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 631	Kannapolis	NC	Solar	8.00	Intermediate/Peaking	Yes
Facility 632	Sylva	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 633	Kannapolis	NC	Solar	14.02	Intermediate/Peaking	Yes
Facility 634	Durham	NC	Solar	3.01	Intermediate/Peaking	Yes
Facility 635	Greensboro	NC	Solar	30.00	Intermediate/Peaking	Yes
Facility 636	Durham	NC	Solar	27.60	Intermediate/Peaking	Yes
Facility 637	Durham	NC	Solar	16.00	Intermediate/Peaking	Yes
Facility 638	Charlotte	NC	Solar	4.80	Intermediate/Peaking	Yes
Facility 639	Wingate	NC	Solar	9.03	Intermediate/Peaking	Yes
Facility 640	Chapel Hill	NC	Solar	20.00	Intermediate/Peaking	Yes
Facility 641	Greensboro	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 642	RTP	NC	Solar	51.00	Intermediate/Peaking	Yes
Facility 643	RTP	NC	Solar	112.00	Intermediate/Peaking	Yes
Facility 644	Chapel Hill	NC	Solar	2.70	Intermediate/Peaking	Yes
Facility 645	Jamestown	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 646	Winston Salem	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 647	Indian Trail	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 648	Elon	NC	Solar	6.02	Intermediate/Peaking	Yes
Facility 649	Winston Salem	NC	Solar	1.92	Intermediate/Peaking	Yes
Facility 650	Chapel Hill	NC	Solar	14.51	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 651	Winston Salem	NC	Solar	9.36	Intermediate/Peaking	Yes
Facility 652	Gibsonville	NC	Solar	14.04	Intermediate/Peaking	Yes
Facility 653	SUMMERFIELD	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 654	Mocksville	NC	Solar	0.70	Intermediate/Peaking	Yes
Facility 655	Moravian Falls	NC	Solar	2.85	Intermediate/Peaking	Yes
Facility 656	McLeansville	NC	Solar	1.44	Intermediate/Peaking	Yes
Facility 657	Charlotte	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 658	Hendersonville	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 659	Ellenboro	NC	Solar	2.65	Intermediate/Peaking	Yes
Facility 660	Brevard	NC	Solar	0.65	Intermediate/Peaking	Yes
Facility 661	Wilkesboro	NC	Solar	4.80	Intermediate/Peaking	Yes
Facility 662	Greensboro	NC	Solar	4.52	Intermediate/Peaking	Yes
Facility 663	Lawndale	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 664	Chapel Hill	NC	Solar	2.30	Intermediate/Peaking	Yes
Facility 665	Matthews	NC	Solar	2.41	Intermediate/Peaking	Yes
Facility 666	Wingate	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 667	Highlands	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 668	FRANKLIN	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 669	Snow Camp	NC	Solar	4.50	Intermediate/Peaking	Yes
Facility 670	Winston Salem	NC	Solar	2.94	Intermediate/Peaking	Yes
Facility 671	Oak Ridge	NC	Solar	7.40	Intermediate/Peaking	Yes
Facility 672	Chapel Hill	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 673	Durham	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 674	Sylva	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 675	Greensboro	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 676	Winston Salem	NC	Solar	22.80	Intermediate/Peaking	Yes
Facility 677	Winston Salem	NC	Solar	3.30	Intermediate/Peaking	Yes
Facility 678	Mebane	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 679	MONROE	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 680	Charlotte	NC	Solar	214.00	Intermediate/Peaking	Yes
Facility 681	Mocksville	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 682	Durham	NC	Wind	3.00	Intermediate/Peaking	Yes
Facility 683	Flat Rock	NC	Wind	1.20	Intermediate/Peaking	Yes
Facility 684	China Grove	NC	Wind	1.00	Intermediate/Peaking	Yes
Facility 685	Shelby	NC	Wind	1.20	Intermediate/Peaking	Yes
Facility 686	FRANKLIN	NC	Wind	1.00	Intermediate/Peaking	Yes
Facility 687	Charlotte	NC	Wind	3.00	Intermediate/Peaking	Yes
Facility 688	N Wilkesboro	NC	Wind	2.40	Intermediate/Peaking	Yes
Facility 689	Maiden	NC	Biogas	10,000.00	Baseload	Yes
Facility 690	Eden	NC	Biomass	700.00	Baseload	Yes
Facility 691	Gastonia	NC	Hydroelectric	640.00	Baseload	Yes
Facility 692	Altamahaw	NC	Hydroelectric	240.00	Baseload	Yes
Facility 693	Caroleen	NC	Hydroelectric	324.00	Baseload	Yes
Facility 694	Burlington	NC	Hydroelectric	440.00	Baseload	Yes
Facility 695	Mooresboro	NC	Hydroelectric	1,600.00	Baseload	Yes
Facility 696	Taylorsville	NC	Hydroelectric	365.00	Baseload	Yes
Facility 697	Dallas	NC	Hydroelectric	820.00	Baseload	Yes
Facility 698	Saxpahaw	NC	Hydroelectric	1,500.00	Baseload	Yes
Facility 699	Eden	NC	Hydroelectric	500.00	Baseload	Yes
Facility 700	Mayodan	NC	Hydroelectric	1,275.00	Baseload	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 701	Mayodan	NC	Hydroelectric	951.00	Baseload	Yes
Facility 702	High Shoals	NC	Hydroelectric	1,800.00	Baseload	Yes
Facility 703	Mill Springs	NC	Hydroelectric	5,500.00	Baseload	Yes
Facility 704	Shelby	NC	Hydroelectric	600.00	Baseload	Yes
Facility 705	Wilkesboro	NC	Hydroelectric	200.00	Baseload	Yes
Facility 706	Cooleemee	NC	Hydroelectric	1,500.00	Baseload	Yes
Facility 707	Lincolnton	NC	Hydroelectric	750.00	Baseload	Yes
Facility 708	Lake Lure	NC	Hydroelectric	3,600.00	Baseload	Yes
Facility 709	Newton	NC	Landfill Gas	4,000.00	Baseload	Yes
Facility 710	Mount Airy	NC	Landfill Gas	1,600.00	Baseload	Yes
Facility 711	Concord	NC	Landfill Gas	11,500.00	Baseload	Yes
Facility 712	Lexington	NC	Landfill Gas	1,600.00	Baseload	Yes
Facility 713	Concord	NC	Landfill Gas	5,000.00	Baseload	Yes
Facility 714	Dallas	NC	Landfill Gas	4,800.00	Baseload	Yes
Facility 715	Durham	NC	Landfill Gas	3,180.00	Baseload	Yes
Facility 716	MADISON	NC	Landfill Gas	800.00	Baseload	Yes
Facility 717	Winston Salem	NC	Landfill Gas	4,750.00	Baseload	Yes
Facility 718	Chapel Hill	NC	Landfill Gas	1,059.00	Baseload	Yes
Facility 719	Boone	NC	Landfill Gas	186.00	Baseload	Yes
Facility 720	Wilkesboro	NC	Landfill Gas	70.00	Baseload	Yes
Facility 721	Kernersville	NC	Landfill Gas	2,400.00	Baseload	Yes
Facility 722	Hendersonville	NC	Solar	8.64	Intermediate/Peaking	Yes
Facility 723	Lincolnton	NC	Solar	75.00	Intermediate/Peaking	Yes
Facility 724	Chapel Hill	NC	Solar	2.80	Intermediate/Peaking	Yes
Facility 725	Fletcher	NC	Solar	95.00	Intermediate/Peaking	Yes
Facility 726	Chapel Hill	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 727	Andrews	NC	Solar	9.60	Intermediate/Peaking	Yes
Facility 728	Winston Salem	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 729	Maiden	NC	Solar	20,000.00	Intermediate/Peaking	Yes
Facility 730	Conover	NC	Solar	20,000.00	Intermediate/Peaking	Yes
Facility 731	Mount Airy	NC	Solar	3,500.00	Intermediate/Peaking	Yes
Facility 732	Chapel Hill	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 733	Claremont	NC	Solar	5,000.00	Intermediate/Peaking	Yes
Facility 734	Chapel Hill	NC	Solar	9.46	Intermediate/Peaking	Yes
Facility 735	Charlotte	NC	Solar	19.68	Intermediate/Peaking	Yes
Facility 736	Lawndale	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 737	Bryson City	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 738	Kings Mountain	NC	Solar	3,500.00	Intermediate/Peaking	Yes
Facility 739	Lawndale	NC	Solar	4,000.00	Intermediate/Peaking	Yes
Facility 740	Conover	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 741	High Point	NC	Solar	3.85	Intermediate/Peaking	Yes
Facility 742	Durham	NC	Solar	124.00	Intermediate/Peaking	Yes
Facility 743	Hendersonville	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 744	Hendersonville	NC	Solar	9.80	Intermediate/Peaking	Yes
Facility 745	Chapel Hill	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 746	Greensboro	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 747	Durham	NC	Solar	7.00	Intermediate/Peaking	Yes
Facility 748	Chapel Hill	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 749	Carrboro	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 750	Troutman	NC	Solar	3.00	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 751	Burlington	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 752	Chapel Hill	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 753	Carrboro	NC	Solar	16.40	Intermediate/Peaking	Yes
Facility 754	Durham	NC	Solar	4.16	Intermediate/Peaking	Yes
Facility 755	Hendersonville	NC	Solar	4.88	Intermediate/Peaking	Yes
Facility 756	Huntersville	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 757	Research Triangle Park	NC	Solar	100.00	Intermediate/Peaking	Yes
Facility 758	Greensboro	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 759	Reidsville	NC	Solar	169.00	Intermediate/Peaking	Yes
Facility 760	Advance	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 761	Brown Summit	NC	Solar	750.00	Intermediate/Peaking	Yes
Facility 762	Carrboro	NC	Solar	9.90	Intermediate/Peaking	Yes
Facility 763	Mocksville	NC	Solar	4,950.00	Intermediate/Peaking	Yes
Facility 764	Chapel Hill	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 765	Durham	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 766	Pisgah Forest	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 767	Greensboro	NC	Solar	6.02	Intermediate/Peaking	Yes
Facility 768	Sandy Ridge	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 769	Lenior	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 770	Sylva	NC	Solar	5.46	Intermediate/Peaking	Yes
Facility 771	Browns Summit	NC	Solar	72.00	Intermediate/Peaking	Yes
Facility 772	Matthews	NC	Solar	30.00	Intermediate/Peaking	Yes
Facility 773	China Grove	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 774	Morrisville	NC	Solar	30.00	Intermediate/Peaking	Yes
Facility 775	Kernersville	NC	Solar	2.23	Intermediate/Peaking	Yes
Facility 776	Pelham	NC	Solar	5,000.00	Intermediate/Peaking	Yes
Facility 777	Chapel Hill	NC	Solar	3.87	Intermediate/Peaking	Yes
Facility 778	Kings Mountain	NC	Solar	4,000.00	Intermediate/Peaking	Yes
Facility 779	Charlotte	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 780	Charlotte	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 781	Burlington	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 782	Winston Salem	NC	Solar	10.56	Intermediate/Peaking	Yes
Facility 783	Chapel Hill	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 784	Chapel Hill	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 785	Charlotte	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 786	Chapel Hill	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 787	Durham	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 788	Elon	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 789	Greensboro	NC	Solar	4.80	Intermediate/Peaking	Yes
Facility 790	Matthews	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 791	Greensboro	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 792	Durham	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 793	Marion	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 794	Graham	NC	Solar	2.70	Intermediate/Peaking	Yes
Facility 795	Glen Alpine	NC	Solar	24.00	Intermediate/Peaking	Yes
Facility 796	Hickory	NC	Solar	4.50	Intermediate/Peaking	Yes
Facility 797	Salisbury	NC	Solar	82.00	Intermediate/Peaking	Yes
Facility 798	Charlotte	NC	Solar	8.00	Intermediate/Peaking	Yes
Facility 799	Tryon	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 800	Pilot Mountain	NC	Solar	10.00	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 801	Cedar Grove	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 802	Bryson City	NC	Solar	7.00	Intermediate/Peaking	Yes
Facility 803	Greensboro	NC	Solar	4.16	Intermediate/Peaking	Yes
Facility 804	Greensboro	NC	Solar	50.00	Intermediate/Peaking	Yes
Facility 805	Hillsborough	NC	Solar	4.20	Intermediate/Peaking	Yes
Facility 806	Chapel Hill	NC	Solar	3.15	Intermediate/Peaking	Yes
Facility 807	N Wilkesboro	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 808	Burlington	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 809	Lincolnton	NC	Solar	5,000.00	Intermediate/Peaking	Yes
Facility 810	Greensboro	NC	Solar	108.00	Intermediate/Peaking	Yes
Facility 811	Durham	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 812	N Wilkesboro	NC	Solar	63.00	Intermediate/Peaking	Yes
Facility 813	Charlotte	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 814	Vale	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 815	Mills River	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 816	Mills River	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 817	Chapel Hill	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 818	Mount Airy	NC	Solar	12.26	Intermediate/Peaking	Yes
Facility 819	Durham	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 820	Matthews	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 821	Highlands	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 822	Charlotte	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 823	Reidsville	NC	Solar	90.00	Intermediate/Peaking	Yes
Facility 824	Wilkesboro	NC	Solar	4.20	Intermediate/Peaking	Yes
Facility 825	Hendersonville	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 826	Chapel Hill	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 827	Concord	NC	Solar	9.80	Intermediate/Peaking	Yes
Facility 828	Hillsborough	NC	Solar	9.80	Intermediate/Peaking	Yes
Facility 829	Jonesville	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 830	Randleman	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 831	Concord	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 832	Charlotte	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 833	Nebo	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 834	Chapel Hill	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 835	Mooresville	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 836	Charlotte	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 837	FRANKLIN	NC	Solar	21.12	Intermediate/Peaking	Yes
Facility 838	Durham	NC	Solar	7.00	Intermediate/Peaking	Yes
Facility 839	Durham	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 840	Salisbury	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 841	Greensboro	NC	Solar	35.48	Intermediate/Peaking	Yes
Facility 842	Kings Mountain	NC	Solar	135.00	Intermediate/Peaking	Yes
Facility 843	Chapel Hill	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 844	Durham	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 845	Chapel Hill	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 846	Marshville	NC	Solar	4,950.00	Intermediate/Peaking	Yes
Facility 847	Huntersville	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 848	Mooresville	NC	Solar	60.00	Intermediate/Peaking	Yes
Facility 849	Mebane	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 850	Charlotte	NC	Solar	3.15	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 851	Mebane	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 852	Mt Airy	NC	Solar	1,000.00	Intermediate/Peaking	Yes
Facility 853	Huntersville	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 854	Yadkinville	NC	Solar	7.80	Intermediate/Peaking	Yes
Facility 855	Charlotte	NC	Solar	1.89	Intermediate/Peaking	Yes
Facility 856	Mocksville	NC	Solar	5,000.00	Intermediate/Peaking	Yes
Facility 857	Pinnacle	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 858	Reidsville	NC	Solar	4,950.00	Intermediate/Peaking	Yes
Facility 859	Charlotte	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 860	Newton	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 861	Gastonia	NC	Solar	635.00	Intermediate/Peaking	Yes
Facility 862	Conover	NC	Solar	135.00	Intermediate/Peaking	Yes
Facility 863	Concord	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 864	Mebane	NC	Solar	221.76	Intermediate/Peaking	Yes
Facility 865	Hillsborough	NC	Solar	18.48	Intermediate/Peaking	Yes
Facility 866	Hillsborough	NC	Solar	18.48	Intermediate/Peaking	Yes
Facility 867	Thomasville	NC	Solar	1,500.00	Intermediate/Peaking	Yes
Facility 868	Charlotte	NC	Solar	8.40	Intermediate/Peaking	Yes
Facility 869	Carrboro	NC	Solar	5.30	Intermediate/Peaking	Yes
Facility 870	Chapel Hill	NC	Solar	3.78	Intermediate/Peaking	Yes
Facility 871	Graham	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 872	Ellenboro	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 873	Brevard	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 874	Sylva	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 875	Charlotte	NC	Solar	33.12	Intermediate/Peaking	Yes
Facility 876	Glenville	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 877	Chapel Hill	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 878	Charlotte	NC	Solar	2.70	Intermediate/Peaking	Yes
Facility 879	Durham	NC	Solar	7.00	Intermediate/Peaking	Yes
Facility 880	Charlotte	NC	Solar	4.10	Intermediate/Peaking	Yes
Facility 881	Mocksville	NC	Solar	9.88	Intermediate/Peaking	Yes
Facility 882	Charlotte	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 883	Chapel Hill	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 884	Chapel Hill	NC	Solar	1.71	Intermediate/Peaking	Yes
Facility 885	Durham	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 886	Belmont	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 887	Hendersonville	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 888	Glenville	NC	Solar	9.90	Intermediate/Peaking	Yes
Facility 889	Greensboro	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 890	Charlotte	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 891	Graham	NC	Solar	5.50	Intermediate/Peaking	Yes
Facility 892	Norwood	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 893	Durham	NC	Solar	4.62	Intermediate/Peaking	Yes
Facility 894	Hendersonville	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 895	Brevard	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 896	Rutherfordton	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 897	McLeansville	NC	Solar	24.00	Intermediate/Peaking	Yes
Facility 898	Greensboro	NC	Solar	5.46	Intermediate/Peaking	Yes
Facility 899	Chapel Hill	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 900	Durham	NC	Solar	4.00	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 901	Concord	NC	Solar	4,500.00	Intermediate/Peaking	Yes
Facility 902	Newton	NC	Solar	4,950.00	Intermediate/Peaking	Yes
Facility 903	Mount Airy	NC	Solar	9.87	Intermediate/Peaking	Yes
Facility 904	Pfafftown	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 905	Chapel Hill	NC	Solar	8.60	Intermediate/Peaking	Yes
Facility 906	Chapel Hill	NC	Solar	5.17	Intermediate/Peaking	Yes
Facility 907	Durham	NC	Solar	1.50	Intermediate/Peaking	Yes
Facility 908	Stoneville	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 909	SUMMERFIELD	NC	Solar	21.40	Intermediate/Peaking	Yes
Facility 910	Charlotte	NC	Solar	115.00	Intermediate/Peaking	Yes
Facility 911	Lexington	NC	Solar	15,500.00	Intermediate/Peaking	Yes
Facility 912	FRANKLIN	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 913	Chapel Hill	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 914	Chapel Hill	NC	Solar	9.24	Intermediate/Peaking	Yes
Facility 915	Burlington	NC	Solar	8.60	Intermediate/Peaking	Yes
Facility 916	Greensboro	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 917	Greensboro	NC	Solar	175.00	Intermediate/Peaking	Yes
Facility 918	Charlotte	NC	Solar	250.00	Intermediate/Peaking	Yes
Facility 919	Hickory	NC	Solar	4.70	Intermediate/Peaking	Yes
Facility 920	Chapel Hill	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 921	Durham	NC	Solar	2.28	Intermediate/Peaking	Yes
Facility 922	Burlington	NC	Solar	1.90	Intermediate/Peaking	Yes
Facility 923	Concord	NC	Solar	4.05	Intermediate/Peaking	Yes
Facility 924	Bryson City	NC	Solar	2.52	Intermediate/Peaking	Yes
Facility 925	Chapel Hill	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 926	Randleman	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 927	Chapel Hill	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 928	Chapel Hill	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 929	Lincolnton	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 930	Chapel Hill	NC	Solar	3.80	Intermediate/Peaking	Yes
Facility 931	Hickory	NC	Solar	3.80	Intermediate/Peaking	Yes
Facility 932	Charlotte	NC	Solar	18.00	Intermediate/Peaking	Yes
Facility 933	Durham	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 934	Hickory	NC	Solar	5,000.00	Intermediate/Peaking	Yes
Facility 935	Durham	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 936	Charlotte	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 937	Charlotte	NC	Solar	27.47	Intermediate/Peaking	Yes
Facility 938	Waco	NC	Solar	4,950.00	Intermediate/Peaking	Yes
Facility 939	Salisbury	NC	Solar	150.00	Intermediate/Peaking	Yes
Facility 940	Statesville	NC	Solar	1.40	Intermediate/Peaking	Yes
Facility 941	Andrews	NC	Solar	8.20	Intermediate/Peaking	Yes
Facility 942	Chapel Hill	NC	Solar	4.32	Intermediate/Peaking	Yes
Facility 943	Chapel Hill	NC	Solar	5,000.00	Intermediate/Peaking	Yes
Facility 944	Saluda	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 945	Chapel Hill	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 946	Greensboro	NC	Solar	4.80	Intermediate/Peaking	Yes
Facility 947	Durham	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 948	Carrboro	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 949	Charlotte	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 950	Thomasville	NC	Solar	82.00	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 951	Brevard	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 952	FRANKLIN	NC	Wind	4.00	Intermediate/Peaking	Yes
Facility 953	Durham	NC	Diesel	4,000.00	Peaking	Yes
Facility 954	Greensboro	NC	Diesel	2,000.00	Peaking	Yes
Facility 955	Hickory	NC	Diesel	1,400.00	Peaking	Yes
Facility 956	Hickory	NC	Diesel	1,750.00	Peaking	Yes
Facility 957	Mount Airy	NC	Diesel	600.00	Peaking	Yes
Facility 958	Mount Airy	NC	Diesel	750.00	Peaking	Yes
Facility 959	Lexington	NC	Diesel	937.50	Peaking	Yes
Facility 960	Durham	NC	Diesel	13,400.00	Peaking	Yes
Facility 961	Hickory	NC	Diesel	625.00	Peaking	Yes
Facility 962	Greensboro	NC	Diesel	850.00	Peaking	Yes
Facility 963	Greensboro	NC	Diesel	2,000.00	Peaking	Yes
Facility 964	Winston-Salem	NC	Diesel	1,900.00	Peaking	Yes
Facility 965	Huntersville	NC	Diesel	1,125.00	Peaking	Yes
Facility 966	Kernersville	NC	Diesel	3,031.00	Peaking	Yes
Facility 967	Matthews	NC	Diesel	906.00	Peaking	Yes
Facility 968	Mebane	NC	Diesel	500.00	Peaking	Yes
Facility 969	Wilkesboro	NC	Diesel	750.00	Peaking	Yes
Facility 970	Cherokee	NC	Diesel	12,500.00	Peaking	Yes
Facility 971	Charlotte	NC	Diesel	13,688.00	Peaking	Yes
Facility 972	Charlotte	NC	Diesel	1,750.00	Peaking	Yes
Facility 973	Mount Holly	NC	Diesel	NA	Peaking	Yes
Facility 974	Charlotte	NC	Diesel	1,250.00	Peaking	Yes
Facility 975	RTP	NC	Diesel	1,300.00	Peaking	Yes
Facility 976	Belmont	NC	Diesel	350.00	Peaking	Yes
Facility 977	Belmont	NC	Diesel	500.00	Peaking	Yes
Facility 978	Belmont	NC	Diesel	350.00	Peaking	Yes
Facility 979	Bessemer City	NC	Diesel	440.00	Peaking	Yes
Facility 980	Charlotte	NC	Diesel	2,250.00	Peaking	Yes
Facility 981	Charlotte	NC	Diesel	1,200.00	Peaking	Yes
Facility 982	Gastonia	NC	Diesel	1,590.00	Peaking	Yes
Facility 983	Mount Holly	NC	Diesel	210.00	Peaking	Yes
Facility 984	Charlotte	NC	Diesel	300.00	Peaking	Yes
Facility 985	Greensboro	NC	Diesel	125.00	Peaking	Yes
Facility 986	Hickory	NC	Diesel	500.00	Peaking	Yes
Facility 987	Charlotte	NC	Diesel	2,200.00	Peaking	Yes
Facility 988	Hendersonville	NC	Diesel	1,000.00	Peaking	Yes
Facility 989	Butner	NC	Diesel	1,250.00	Peaking	Yes
Facility 990	Carrboro	NC	Diesel	500.00	Peaking	Yes
Facility 991	Chapel Hill	NC	Diesel	1,135.00	Peaking	Yes
Facility 992	Chapel Hill	NC	Diesel	500.00	Peaking	Yes
Facility 993	Chapel Hill	NC	Diesel	2,000.00	Peaking	Yes
Facility 994	RTP	NC	Diesel	350.00	Peaking	Yes
Facility 995	Butner	NC	Diesel	750.00	Peaking	Yes
Facility 996	Elkin	NC	Diesel	400.00	Peaking	Yes
Facility 997	Valdese	NC	Diesel	600.00	Peaking	Yes
Facility 998	Mooresville	NC	Diesel	750.00	Peaking	Yes
Facility 999	Salisbury	NC	Diesel	1,500.00	Peaking	Yes
Facility 1000	Winston-Salem	NC	Diesel	3,750.00	Peaking	Yes
Facility 1001	Winston-Salem	NC	Diesel	2,000.00	Peaking	Yes

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

Table H-4 Non-Utility Generation- South Carolina

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
			South Carolina Generators:			
Facility 1	Gaffney	SC	Other	-	Intermediate/Peaking	Yes
Facility 2	Greenville	SC	Solar	21.00	Intermediate/Peaking	Yes
Facility 3	Spartanburg	SC	Solar	0.86	Intermediate/Peaking	Yes
Facility 4	Greer	SC	Solar	15.00	Intermediate/Peaking	Yes
Facility 5	Spartanburg	SC	Solar	0.76	Intermediate/Peaking	Yes
Facility 6	Williamston	SC	Solar	10.00	Intermediate/Peaking	Yes
Facility 7	Clemson	SC	Solar	2.35	Intermediate/Peaking	Yes
Facility 8	Lyman	SC	Solar	94.08	Intermediate/Peaking	Yes
Facility 9	Piedmont	SC	Solar	0.86	Intermediate/Peaking	Yes
Facility 10	Spartanburg	SC	Solar	0.76	Intermediate/Peaking	Yes
Facility 11	Simpsonville	SC	Solar	2.15	Intermediate/Peaking	Yes
Facility 12	Greer	SC	Solar	5.52	Intermediate/Peaking	Yes
Facility 13	Greer	SC	Solar	1.68	Intermediate/Peaking	Yes
Facility 14	Clover	SC	Solar	2.80	Intermediate/Peaking	Yes
Facility 15	Lancaster	SC	Solar	5.00	Intermediate/Peaking	Yes
Facility 16	Greenville	SC	Solar	1.72	Intermediate/Peaking	Yes
Facility 17	Easley	SC	Solar	11.00	Intermediate/Peaking	Yes
Facility 18	Ridgeway	SC	Solar	2.40	Intermediate/Peaking	Yes
Facility 19	Seneca	SC	Solar	3.60	Intermediate/Peaking	Yes
Facility 20	Hodges	SC	Solar	7.50	Intermediate/Peaking	Yes
Facility 21	Greenville	SC	Solar	1.80	Intermediate/Peaking	Yes
Facility 22	Clemson	SC	Solar	42.00	Intermediate/Peaking	Yes
Facility 23	Greenville	SC	Solar	3.20	Intermediate/Peaking	Yes
Facility 24	Taylors	SC	Solar	5.00	Intermediate/Peaking	Yes
Facility 25	Spartanburg	SC	Solar	7.00	Intermediate/Peaking	Yes
Facility 26	Clemson	SC	Solar	4.50	Intermediate/Peaking	Yes
Facility 27	Gray Court	SC	Solar	0.76	Intermediate/Peaking	Yes
Facility 28	Taylors	SC	Solar	2.28	Intermediate/Peaking	Yes
Facility 29	Hodges	SC	Solar	6.00	Intermediate/Peaking	Yes
Facility 30	Campobello	SC	Solar	3.01	Intermediate/Peaking	Yes
Facility 31	Greenville	SC	Solar	2.86	Intermediate/Peaking	Yes
Facility 32	Greenville	SC	Solar	7.00	Intermediate/Peaking	Yes
Facility 33	Greenville	SC	Solar	20.00	Intermediate/Peaking	Yes
Facility 34	Greenwood	SC	Solar	2.76	Intermediate/Peaking	Yes
Facility 35	Inman	SC	Solar	6.00	Intermediate/Peaking	Yes
Facility 36	Cowpens	SC	Solar	0.74	Intermediate/Peaking	Yes
Facility 37	Easley	SC	Solar	19.00	Intermediate/Peaking	Yes
Facility 38	Fountain Inn	SC	Solar	2.53	Intermediate/Peaking	Yes
Facility 39	Simponville	SC	Solar	0.86	Intermediate/Peaking	Yes
Facility 40	Lancaster	SC	Solar	10.00	Intermediate/Peaking	Yes
Facility 41	Spartanburg	SC	Solar	2.80	Intermediate/Peaking	Yes
Facility 42	Simpsonville	SC	Solar	1.44	Intermediate/Peaking	Yes
Facility 43	Clover	SC	Solar	2.85	Intermediate/Peaking	Yes
Facility 44	Sunset	SC	Solar	9.00	Intermediate/Peaking	Yes
Facility 45	Greenville	SC	Solar	14.00	Intermediate/Peaking	Yes
Facility 46	Spartanburg	SC	Solar	0.86	Intermediate/Peaking	Yes
Facility 47	Taylors	SC	Solar	0.76	Intermediate/Peaking	Yes
Facility 48	Seneca	SC	Solar	10.08	Intermediate/Peaking	Yes
Facility 49	Greenville	SC	Solar	29.83	Intermediate/Peaking	Yes
Facility 50	Cleveland	SC	Solar	3.12	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 51	Greenville	SC	Solar	100.00	Intermediate/Peaking	Yes
Facility 52	Greenville	SC	Solar	4.30	Intermediate/Peaking	Yes
Facility 53	Campobello	SC	Solar	2.15	Intermediate/Peaking	Yes
Facility 54	Gray Court	SC	Solar	5.64	Intermediate/Peaking	Yes
Facility 55	Moore	SC	Solar	3.00	Intermediate/Peaking	Yes
Facility 56	Greenville	SC	Solar	30.10	Intermediate/Peaking	Yes
Facility 57	Williamston	SC	Solar	6.88	Intermediate/Peaking	Yes
Facility 58	Greenville	SC	Solar	5.16	Intermediate/Peaking	Yes
Facility 59	Taylors	SC	Solar	10.00	Intermediate/Peaking	Yes
Facility 60	Fountain Inn	SC	Solar	49.00	Intermediate/Peaking	Yes
Facility 61	Pelzer	SC	Solar	1.94	Intermediate/Peaking	Yes
Facility 62	Greenville	SC	Solar	4.30	Intermediate/Peaking	Yes
Facility 63	Clover	SC	Solar	2.10	Intermediate/Peaking	Yes
Facility 64	Moore	SC	Solar	4.30	Intermediate/Peaking	Yes
Facility 65	Spartanburg	SC	Solar	0.76	Intermediate/Peaking	Yes
Facility 66	Pacolet	SC	Solar	0.86	Intermediate/Peaking	Yes
Facility 67	Spartanburg	SC	Solar	0.19	Intermediate/Peaking	Yes
Facility 68	Greenville	SC	Solar	3.44	Intermediate/Peaking	Yes
Facility 69	SALEM	SC	Solar	4.00	Intermediate/Peaking	Yes
Facility 70	Greenville	SC	Solar	3.00	Intermediate/Peaking	Yes
Facility 71	Six Mile	SC	Solar	1.05	Intermediate/Peaking	Yes
Facility 72	Tega Cay	SC	Solar	5.41	Intermediate/Peaking	Yes
Facility 73	Central	SC	Solar	13.00	Intermediate/Peaking	Yes
Facility 74	Piedmont	SC	Solar	8.00	Intermediate/Peaking	Yes
Facility 75	Piedmont	SC	Solar	4.84	Intermediate/Peaking	Yes
Facility 76	Central	SC	Solar	4.20	Intermediate/Peaking	Yes
Facility 77	Central	SC	Solar	2.62	Intermediate/Peaking	Yes
Facility 78	Sharon	SC	Solar	2.99	Intermediate/Peaking	Yes
Facility 79	Greenville	SC	Solar	3.36	Intermediate/Peaking	Yes
Facility 80	Six Mile	SC	Solar	4.00	Intermediate/Peaking	Yes
Facility 81	Pelzer	SC	Solar	2.94	Intermediate/Peaking	Yes
Facility 82	Pickens	SC	Solar	15.60	Intermediate/Peaking	Yes
Facility 83	Pelzer	SC	Solar	1.94	Intermediate/Peaking	Yes
Facility 84	Greenville	SC	Solar	1.30	Intermediate/Peaking	Yes
Facility 85	Simpsonsville	SC	Solar	1.94	Intermediate/Peaking	Yes
Facility 86	Campobello	SC	Solar	3.85	Intermediate/Peaking	Yes
Facility 87	Chesnee	SC	Solar	0.86	Intermediate/Peaking	Yes
Facility 88	Gray Court	SC	Solar	8.60	Intermediate/Peaking	Yes
Facility 89	Spartanburg	SC	Solar	2.85	Intermediate/Peaking	Yes
Facility 90	Honea Path	SC	Solar	3.82	Intermediate/Peaking	Yes
Facility 91	Greer	SC	Solar	10.00	Intermediate/Peaking	Yes
Facility 92	Greenville	SC	Solar	15.00	Intermediate/Peaking	Yes
Facility 93	Spartanburg	SC	Solar	0.19	Intermediate/Peaking	Yes
Facility 94	Duncan	SC	Solar	6.00	Intermediate/Peaking	Yes
Facility 95	Inman	SC	Solar	3.78	Intermediate/Peaking	Yes
Facility 96	Piedmont	SC	Solar	1.04	Intermediate/Peaking	Yes
Facility 97	Belton	SC	Solar	6.14	Intermediate/Peaking	Yes
Facility 98	Lyman	SC	Solar	0.74	Intermediate/Peaking	Yes
Facility 99	Greenville	SC	Solar	10.00	Intermediate/Peaking	Yes
Facility 100	Greenville	SC	Solar	5.00	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 101	Greenville	SC	Solar	14.00	Intermediate/Peaking	Yes
Facility 102	Taylors	SC	Solar	1.72	Intermediate/Peaking	Yes
Facility 103	Cleveland	SC	Solar	4.80	Intermediate/Peaking	Yes
Facility 104	Greenville	SC	Solar	3.01	Intermediate/Peaking	Yes
Facility 105	Ninety Six	SC	Solar	7.52	Intermediate/Peaking	Yes
Facility 106	SALEM	SC	Solar	2.15	Intermediate/Peaking	Yes
Facility 107	Spartanburg	SC	Solar	5.00	Intermediate/Peaking	Yes
Facility 108	Easley	SC	Solar	6.58	Intermediate/Peaking	Yes
Facility 109	Greenville	SC	Solar	2.38	Intermediate/Peaking	Yes
Facility 110	Roebuck	SC	Solar	4.00	Intermediate/Peaking	Yes
Facility 111	Chesnee	SC	Solar	1.47	Intermediate/Peaking	Yes
Facility 112	Fort Mill	SC	Solar	10.97	Intermediate/Peaking	Yes
Facility 113	Greenville	SC	Solar	6.72	Intermediate/Peaking	Yes
Facility 114	Catawba	SC	Solar	2.50	Intermediate/Peaking	Yes
Facility 115	Travelers Rest	SC	Solar	3.01	Intermediate/Peaking	Yes
Facility 116	Williamston	SC	Solar	2.38	Intermediate/Peaking	Yes
Facility 117	Chester	SC	Solar	2.47	Intermediate/Peaking	Yes
Facility 118	Fort Mill	SC	Solar	5.16	Intermediate/Peaking	Yes
Facility 119	Greenville	SC	Solar	4.68	Intermediate/Peaking	Yes
Facility 120	Clover	SC	Solar	0.70	Intermediate/Peaking	Yes
Facility 121	Piedmont	SC	Solar	19.40	Intermediate/Peaking	Yes
Facility 122	Reidville	SC	Solar	2.20	Intermediate/Peaking	Yes
Facility 123	Greenville	SC	Solar	15.00	Intermediate/Peaking	Yes
Facility 124	Simpsonville	SC	Solar	5.00	Intermediate/Peaking	Yes
Facility 125	Greer	SC	Solar	8.00	Intermediate/Peaking	Yes
Facility 126	Greenville	SC	Solar	0.76	Intermediate/Peaking	Yes
Facility 127	Spartanburg	SC	Solar	0.86	Intermediate/Peaking	Yes
Facility 128	Campobello	SC	Solar	4.20	Intermediate/Peaking	Yes
Facility 129	Greer	SC	Solar	3.00	Intermediate/Peaking	Yes
Facility 130	Greenville	SC	Solar	4.00	Intermediate/Peaking	Yes
Facility 131	Rock Hill	SC	Solar	2.50	Intermediate/Peaking	Yes
Facility 132	Clover	SC	Solar	7.00	Intermediate/Peaking	Yes
Facility 133	Inman	SC	Solar	1.52	Intermediate/Peaking	Yes
Facility 134	Rock Hill	SC	Solar	8.09	Intermediate/Peaking	Yes
Facility 135	Greenville	SC	Solar	1.80	Intermediate/Peaking	Yes
Facility 136	Campobello	SC	Solar	10.00	Intermediate/Peaking	Yes
Facility 137	Belton	SC	Solar	2.14	Intermediate/Peaking	Yes
Facility 138	Rock Hill	SC	Solar	21.00	Intermediate/Peaking	Yes
Facility 139	Simpsonville	SC	Solar	6.00	Intermediate/Peaking	Yes
Facility 140	Landrum	SC	Solar	4.00	Intermediate/Peaking	Yes
Facility 141	Moore	SC	Solar	5.23	Intermediate/Peaking	Yes
Facility 142	Landrum	SC	Solar	2.10	Intermediate/Peaking	Yes
Facility 143	Travelers Rest	SC	Solar	2.50	Intermediate/Peaking	Yes
Facility 144	Pelzer	SC	Solar	5.40	Intermediate/Peaking	Yes
Facility 145	Williamston	SC	Solar	2.38	Intermediate/Peaking	Yes
Facility 146	Roebuck	SC	Solar	0.27	Intermediate/Peaking	Yes
Facility 147	Reidville	SC	Wind	1.20	Intermediate/Peaking	Yes
Facility 148	Piedmont	SC	Hydroelectric	600.00	Baseload	Yes
Facility 149	Ware Shoals	SC	Hydroelectric	6,300.00	Baseload	Yes
Facility 150	Spartanburg	SC	Hydroelectric	1,250.00	Baseload	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 151	Enoree	SC	Hydroelectric	1,600.00	Baseload	Yes
Facility 152	Belton	SC	Hydroelectric	3,500.00	Baseload	Yes
Facility 153	Greenville	SC	Hydroelectric	2,400.00	Baseload	Yes
Facility 154	Laurens	SC	Hydroelectric	1,500.00	Baseload	Yes
Facility 155	Anderson	SC	Hydroelectric	2,020.00	Baseload	Yes
Facility 156	Williamston	SC	Hydroelectric	3,300.00	Baseload	Yes
Facility 157	Chesnee	SC	Hydroelectric	1,000.00	Baseload	Yes
Facility 158	Greer	SC	Landfill Gas	3,200.00	Baseload	Yes
Facility 159	Wellford	SC	Landfill Gas	1,600.00	Baseload	Yes
Facility 160	Fountain Inn	SC	Solar	5.16	Intermediate/Peaking	Yes
Facility 161	Gray Court	SC	Solar	6.00	Intermediate/Peaking	Yes
Facility 162	West Union	SC	Solar	56.70	Intermediate/Peaking	Yes
Facility 163	Ware Shoals	SC	Solar	1.94	Intermediate/Peaking	Yes
Facility 164	Greenville	SC	Solar	5.89	Intermediate/Peaking	Yes
Facility 165	Walhalla	SC	Solar	4.73	Intermediate/Peaking	Yes
Facility 166	Anderson	SC	Solar	3.44	Intermediate/Peaking	Yes
Facility 167	Simpsonville	SC	Solar	5.16	Intermediate/Peaking	Yes
Facility 168	Anderson	SC	Diesel	4,000.00	Peaking	Yes
Facility 169	Greenwood	SC	Diesel	1,500.00	Peaking	Yes
Facility 170	Clinton	SC	Diesel	447.00	Peaking	Yes
Facility 171	Kershaw	SC	Diesel	1,875.00	Peaking	Yes
Facility 172	Spartanburg	SC	Diesel	500.00	Peaking	Yes
Facility 173	Spartanburg	SC	Diesel	2,900.00	Peaking	Yes

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

Table H-5 DEC QF Interconnection Queue

Qualified Facilities contribute to the current and future resource mix of the Company. QFs that are under contract are captured as designated resources in the base resource plan. QFs that are not yet under contract but in the interconnection queue may contribute to the undesignated additions identified in the resource plans. It is not possible to precisely estimate how much of the interconnection queue will come to fruition, however the current queue clearly supports solar's central role in DEC's NC REPS compliance plan.

Below is a summary of the interconnection queue as of June 2014:

Utility	Facility State	Energy Source Type	Number of Pending Projects	Pending Capacity MW AC
DEC	NC	Solar	126	713.37
		Biomass	2	3.50
		Hydro	2	31.50
		Biogas	1	5.20
		Hydroelectric	1	0.01
DEC	**NC Total**		**132**	**753.58**
	SC	Hydroelectric	1	0.25
DEC	**SC Total**		**1**	**0.25**
DEC Total			**133**	**753.83**

Note: (1) Above table includes all QF projects that are in various phases of the interconnection queue and not yet generating energy.
(2) Table does not include net metering interconnection requests.

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 line projects that DEC agreed to construct as part of its merger commitments have been completed. Table I-1 lists the line projects that are planned to meet reliability needs. This appendix also provides information pursuant to the North Carolina Utility Commission Rule R8-62.

Table I-1: DEC Transmission Line Additions

YEAR	PROJECT	CAPACITY
	NONE	N/A

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, 2014.

(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.

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. Generator interconnection requests are studied in accordance with the Large and Small Generator Interconnection Procedures in the OATT.

Southeastern Reliability Corporation (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 2014. The scope of this audit included standards impacting the Transmission Planning area. DEC received "No Findings" from the audit team in the Transmission Planning area.

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 2014 is:

Rider EC:
194 MW for North Carolina
77 MW for South Carolina

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

APPENDIX K: CARBON NEUTRAL PLAN

Greenhouse Gas Reduction Compliance Plan – Cliffside Unit 6

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

With regard to obligation (1) identified above, as shown in Table K-1 below, Duke Energy Carolinas proposes to retire up to 1,299 MW at the following generating units to satisfy the required retirement schedule set forth in the Greenhouse Plan.

Table K-1 - Cumulative Coal Plant Retirements

	Greenhouse Plan Retirement Schedule Capacity in MW	IRP Retirement Schedule Capacity in MW (Appendix B)[1]	Description for IRP Retirement Schedule
by end of 2011		113	Buck 3 & 4
by end of 2012		389	Dan River 1-3
by end of 2013		1099	Riverbend 4 - 7, Buck 5 & 6
by end of 2015	350	1299	Lee 1&2; Note [2]
by end of 2018	**800**	**1299**	

[1] In the 2014 IRP, this data appears in Appendix B. References have been updated to match the 2014 IRP.
[2] The IRP Retirement Schedule indicates that the retirements would exceed the Greenhouse Plan by close to 50%.

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

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

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

Duke Energy Carolinas included the plan for carbon neutrality in the 2011 IRP in order to satisfy the requirement to file and seek approval of the plan from the NCUC as required by the NC Department of Air Quality (NCDAQ) Air Permit. The NCUC's Order Approving 2011 Annual Updates to 2010 Biennial Resource Plans and 2011 REPS Compliance Plans issued on May 30, 2012, states that "the Commission is approving the Plan itself as a reasonable path for Duke's compliance with the carbon emission reduction standards of the air quality permit and is not approving any individual specific activities nor expenditures for any activities shown in the Plan."

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

Table K-2 - Emission Reduction Requirement

Actions	**Tons of CO_2 Equivalent Emissions**	**Notes**
Cliffside Unit 6	6,000,000	Expected Annual Emissions (based on an approximate 90% capacity factor)
Less Cliffside Units 1 – 4	(681,954)	Average of emissions in 2007 & 2008[1]
Total Increase	**5,318,046**	**Emissions Reduction Requirement**

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

The Company's plan for meeting the Emissions Reductions Requirements includes actions from multiple categories and associated methodologies for determining the offset value known as "Qualifying Actions" (defined below and as further indicated in Table K-3).

For 2018, the Company has identified approximately 8.8 million annual tons of carbon dioxide emissions reductions and a lifetime credit of 600,000 tons of carbon dioxide bio-sequestration as eligible Qualifying Actions (See Table K-3). The Qualifying Actions include the avoidance of carbon dioxide emission releases from coal plant retirements, addition of renewable resources, implementation of energy efficiency measures, nuclear and hydropower capacity upgrades. This also includes the expected retirement of coal-fired operations at Lee Units 1, 2 and 3 in South Carolina in 2015. In addition, carbon dioxide bio-sequestration offsets from the Greentrees program, which sequesters carbon as trees grow, is identified as a Qualifying Action.

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

Table K-3 - Qualifying Actions for carbon dioxide emission reductions

Categories	**Tons of CO_2 Equivalent Emissions**	**Methodology Description**
Buck 3	216,202	Average of emissions in 2007 & 2008[1]
Buck 4	139,429	Average of emissions in 2007 & 2008[1]
Buck 5	606,837	Average of emissions in 2007 & 2008[1]
Buck 6	653,860	Average of emissions in 2007 & 2008[1]
Riverbend 4	462,314	Average of emissions in 2007 & 2008[1]
Riverbend 5	435,895	Average of emissions in 2007 & 2008[1]
Riverbend 6	684,010	Average of emissions in 2007 & 2008[1]
Riverbend 7	710,023	Average of emissions in 2007 & 2008[1]
Dan River 1	249,900	Average of emissions in 2007 & 2008[1]
Dan River 2	282,944	Average of emissions in 2007 & 2008[1]
Dan River 3	677,334	Average of emissions in 2007 & 2008[1]
Lee 1 [5]	335,583	Average of emissions in 2007 & 2008[1]
Lee 2 [5]	390,965	Average of emissions in 2007 & 2008[1]
Lee 3 [5]	783,658	Average of emissions in 2007 & 2008[1]
Conservation	774,800	In 2018, 1,937,000 MWH "Conservation and Demand Side Management Programs"[2] is multiplied by a Conversion Factor of 0.40.
Renewable Energy[6]	622.841	In 2018, 589 MW per the Table 5-A "MW Nameplate Capacity".[3] Is multiplied by an assumed 30% (wind), 20% (solar), and 85% (biomass) capacity factor and a Conversion Factor of 0.40.
Bridgewater Hydro	7,997	Indicates 8.75 MW increase in capacity. This is multiplied by a 26% capacity factor and a Conversion Factor of 0.40.
Nuclear Uprates	760,144	Assumed 236 MW of nuclear uprates by June of 2018.[4] Assumed a 92% capacity factor and a Conversion Factor of 0.40.
Total Annual	8,794,736	

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

[2] Data is from Appendix D of the 2014 IRP.

[3] Data is from the Table 5-A of the 2014 IRP. Actual nameplate capacity is 589 MW. The contribution to peak is 321 MW.

[4] Data is a portion of the total capacity addition on Appendix B of 2014 IRP prior to June 2018.

[5] Lee Units 1, 2 and 3 are planned for retirement by April 15, 2015. Alternatively, Duke Energy is converting Lee 3 to natural gas to allow continued operation for peak generation demand only (at a low annual capacity factor). Any CO_2 from operating with natural gas would be subtracted from the reductions shown in the table.

[6] The renewable resources used in this calculation only include those utilized for compliance and do not include the renewable QF purchases not used for compliance.

As the proposed Plan methodology has been approved, Duke Energy Carolinas shall provide a compliance report in the 2019 IRP filing indicating what Qualifying Actions were used to meet the Emission Reduction Requirement in 2018. The expected Qualifying Actions total 8.8 million tons of emission reductions by 2018. The Company's proposed Qualifying Actions clearly demonstrate that identified reductions can more than exceed the Required Emissions Reduction estimate of 5.3 million tons.

APPENDIX L: CROSS-REFERENCE OF IRP REQUIREMENTS AND SUBSEQUENT ORDERS

The following table cross-references IRP regulatory requirements for NC R8-60 in North Carolina and SC 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 following table cross-references Subsequent Orders for information that is required by the NCUC for inclusion in future IRP documents.

Change	Location	Source (Docket and Order Date)	Updated
Electric utilities shall include in future IRPs a full discussion of drivers of each class's load forecast, including new or changed demand of a particular sector or sub-group	Ch 3 & App C	E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 9 E-100, Sub 133, Order Denying Rulemaking Petition (Allocation Methods), dated 10/30/12, ordering paragraph 4	Yes
To the extent an IOU selects a preferred resource scenario based on fuel diversity, the IOU should provide additional support for its decision based on the costs and benefits of alternatives to achieve the same goals	N/A	E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 13	N/A
DEP and DEC shall provide information on the number, resource type and total capacity of the facilities currently within the respective utility's interconnection queue as well as a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs	App H	E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 14	Yes
Consistent with the Commission's May 7, 2013 Order in M-100, Sub 135, the IOUs shall include with their 2014 IRP submittals verified testimony addressing natural gas issues (gas supply procurement and long-term gas supply adequacy and reliability)	App E	E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 15 E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 17	Yes
All IOUs shall include in future IRPs a full discussion of the drivers of each class' load forecast, including new or changed demand of a particular sector or sub-group	Ch 3 & App C	E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 10	Yes
DEC shall … provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit	App K	E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 12	Yes
DEP and DNCP shall provide additional details and discussion of projected alternative supply side resources similar to the information provided by DEC	N/A	E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 14	N/A
DEC and DEP should consider additional resource scenarios that include larger amounts of renewable energy resources similar to DNCP's Renewable Plan, and to the extent those scenarios are not selected, discuss why the scenario was not selected	Ch 8, App A	E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 15	Yes
To the extent an IOU selects a preferred resource scenario based on fuel diversity, the IOU should provide additional support for its decision based on the costs and benefits of alternatives to achieve the same goals	N/A	E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 16	N/A
DEP, DEC and DNCP shall annually review their REPS compliance plans from four years earlier and disclose any redacted information that is no longer a trade secret [This is filed in the docket of the prior IRP rather than the new IRP.]	Attached NC REPS Compliance Plan	E-100, Sub 137, Order Granting in Part and Denying in Part Motion for Disclosure, dated 6/3/13, ordering paragraph 3	Yes

[2013] Duke shall show the peak demand and energy savings impacts of each measure/option in the Program separately from each other, and separately from the impacts of its other existing PowerShare DSM program options in its future IRP and DSM filings, and in its evaluation, measurement, and verification reports for each measure of the Program [2011] Duke shall show the impacts of the Program separately from the impacts of its existing PowerShare DSM options in future IRP and DSM filings, and Duke shall conduct and present separate M&V of the Program's impacts	App D	E-7, Sub 953, Order Approving Amended Program, dated 1/24/13, ordering paragraph 4 (PowerShare Call Option Nonresidential Load and Curtailment Program) E-7, Sub 953, Order Approving Program, dated 3/31/11, ordering paragraph 4	Yes
DEP will incorporate into future IRPs any demand and energy savings resulting from the Small Business Energy Saver Program and Residential New Construction Program	N/A	E-2, Sub 1022, Order Approving Program, dated 11/5/12, footnote 2 (Small Business Energy Saver) E-2, Sub 1021, Order Approving Program, dated 10/2/12, footnote 3 (Residential New Construction Program)	N/A
Each IOU shall include a discussion of a variance of 10% or more in projected EE savings from one IRP report to the next	App D	E-100, Sub 128, Order Approving 2011 Annual Updates to 2010 IRPs and 2011 REPS Compliance Plans, dated 5/30/12, ordering paragraph 8	Yes
Each IOU shall include a discussion of the status of market potential studies or updates in their 2012 and future IRPs	Ch 4 & App A, D	E-100, Sub 128, Order Approving 2011 Annual Updates to 2010 IRPs and 2011 REPS Compliance Plans, dated 5/30/12, ordering paragraph 9	Yes
Each utility shall include in each biennial report potential impacts of smart grid technology on resource planning and load forecasting: a present and five-year outlook – see R8-60(i)(10)	App D	E-100, Sub 126, Order Amending Commission Rule R8-60 and Adopting Commission Rule R8-60.1, dated 4/11/12	Yes
Each IOU and EMC shall investigate the value of activating DSM resources during times of high system load as a means of achieving lower fuel costs by not having to dispatch peaking units with their associated higher fuel costs if it is less expensive to activate DSM resources. This issue shall be addressed as a specific item in their 2012 biennial IRP reports. [Note: the 10/14/13 Order in E-100, Sub 137 did not include this requirement for future IRPs; FoF 5 stated "The IOUs and EMCs included a full discussion of their DSM programs and their use of these resources a required by Rule R8-60(i)(6)."]	N/A	E-100, Sub 128, Order Approving 2010 Biennial Integrated Resource Plans and 2010 REPS Compliance Plans, dated 10/26/11, ordering paragraph 12	N/A
DEP and DEC shall prepare a comprehensive reserve margin requirements study and include it as part of its 2012 biennial IRP report. DEP and DEC shall keep the Public Staff updated as they develop the parameters of the studies. [Study was included in 2012 IRP, as required.]	N/A	E-100, Sub 128, Order Approving 2010 Biennial Integrated Resource Plans and 2010 REPS Compliance Plans, dated 10/26/11, ordering paragraph 13	N/A
All utilities shall provide the amount of load and projected load growth for each wholesale customer under contract on a year-by-year basis through the terms of the current contract; segregate actual and projected growth rates of retail and wholesale loads, and explain any difference in actual and projected growth rates between retail and wholesale loads	App C	E-100, Sub 118 and Sub 124, Order Approving Integrated Resource Plans and REPS Compliance Plans (2008-09), dated 8/10/10, ordering paragraph 6	Yes
All utilities shall, for any amount of undesignated load, detail each potential customer's current supply arrangements and explain the basis for the utility's reasonable expectation for serving each such customer	App H	E-100, Sub 118 and Sub 124, Order Approving Integrated Resource Plans and REPS Compliance Plans (2008-09), dated 8/10/10, ordering paragraph 6	Yes
DEP shall reflect plant retirements and address its progress in retiring its unscrubbed coal units by updates in its annual IRP filings	N/A	E-2, Sub 960, Order Approving Plan, dated 1/28/10, ordering paragraph 2 (Wayne County CCs CPCN)	N/A

The Duke Energy Carolinas

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

September 1, 2014

NC REPS Compliance Plan
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I. INTRODUCTION

Duke Energy Carolinas, LLC (Duke Energy Carolinas or the Company) submits its annual Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS or REPS) Compliance Plan (Compliance Plan) in accordance with NC 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 2014 to 2016 (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 NC 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) 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) 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 NC 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. <u>REPS COMPLIANCE OBLIGATION</u>

Duke Energy Carolinas calculates its NC REPS Compliance Obligations[9] in 2014, 2015, and 2016 based on interpretation of the statute (NC 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)[10]. Table 1 below shows the Company's retail and Wholesale customers' REPS Compliance Obligation.

[9] 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.

[10] 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 (MWhs)	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)
2014	55,394,590	3,418,816	58,813,405	41,169	41,169	79,443	3%	1,764,402
2015	56,560,699	3,452,964	60,013,663	84,019	42,010	324,782	6%	3,600,820
2016	57,179,101	3,479,686	60,658,787	84,922	84,922	418,599	6%	3,639,527

Note: Obligation is determined by prior-year MWh sales. Thus, retail sales figures for compliance years 2015 and 2016 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 year 2014, and 6% of its prior year retail sales in compliance years 2015 and 2016. 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 NC 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 2014, rising to a minimum of 0.14% in 2015 and 2016.

Based on the Company's actual retail sales in 2013, the Solar Set-Aside is approximately 41,169 RECs in 2014. Based on forecasted retail sales, the Solar Set-Aside is projected to be approximately 84,019 RECs and 84,922 RECs in 2015 and 2016, 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. Company Owned Solar Facilities

The Company currently owns installations across multiple sites totaling approximately 8MW-AC 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. The Company plans to pursue ownership of additional generation, as appropriate.

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 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 NC Gen. Stat. § 62-133.8(e) as modified by the Commission[11], for calendar years 2014 and 2015, 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 2016, 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 41,169 RECs in 2014, 42,010 RECs in 2015, and 84,922 RECs in 2016.

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 2014. 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 2015 and 2016 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.

[11] See *Final Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Providing Other Relief*, Docket No. E-100, Sub 113 (March 2014).

Due to its expected non-compliance in 2014, the Company has submitted 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 NC Gen. Stat. § 62-133.8(f) and as amended by NCUC *Final Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Providing Other Relief,* Docket No. E-100, Sub 113 (March 2014), for calendar years 2014, 2015, and 2016, 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 47%, the Company's Poultry Set-Aside is estimated to be 79,433 RECs in 2014, 324,782 RECs in 2015, and 418,599 in 2016.

As a result of Duke Energy Carolinas' active and diligent efforts to secure resources to comply with its Poultry Set-Aside requirements, the Company has secured, or contracted for delivery, sufficient volumes of RECs to meet its pro-rata share of the poultry set-aside requirements in 2014, with actual compliance dependent upon multiple variables, particularly relating to counterparty achievement of projected delivery requirements and commercial operation milestones. 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 and 2016 remains uncertain and largely subject to counterparty performance. 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.

D. GENERAL REQUIREMENT RESOURCES

Pursuant to NC Gen. Stat. § 62-133.8, Duke Energy Carolinas is required to comply with its Total Obligation in 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 and 2016: approximately 1,764,402 RECs in 2014, 3,600,820 RECs in 2015, and 3,639,527 RECs in 2016. This requirement, net of the Solar, Swine, and Poultry Set-Aside requirements, is estimated to be 1,602,620 RECs in 2014, 3,150,009 RECs in 2015, and 3,051,084 in 2016. 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 NC Gen. Stat. § 62-133.7(b)(2)c. This will be accomplished by utilizing EE savings from the Company's Commission-approved programs. The Company will 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 NC 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 NC 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 hydro facilities, 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 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 remains limited in long-term planning horizons, 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 previous IRP's, 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, availability of Federal tax subsidies 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. 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 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.

The projected avoided costs rates contained herein are subject to change, particularly as the underlying assumptions change and as the methodology for determining the avoided cost is addressed by the North Carolina Utilities Commission in pending Docket No. E-100, Sub 140. Primary assumptions that impact avoided cost rates are turbine costs, fuel price projections, and the expansion plans. Changes to these assumptions are addressed in greater detail in the current Integrated Resource Plan.

Table 2: Current and Projected Avoided Cost Rates Table

[BEGIN CONFIDENTIAL]

CURRENT AVOIDED ENERGY AND CAPACITY COST (from E-100 Sub 136)			
	On-Peak Energy(1) ($/MWh)	Off-Peak Energy(1) ($/MWh)	[redacted]
2015	52.19	41.05	[redacted]
2016	50.82	41.22	[redacted]
2017	51.67	42.89	[redacted]

PROJECTED AVOIDED ENERGY AND CAPACITY COST(4)			
	On-Peak Energy(1) ($/MWh)	Off-Peak Energy(1) ($/MWh)	[redacted]
2015	48.07	39.31	[redacted]
2016	48.31	38.32	[redacted]
2017	50.01	38.56	[redacted]

Notes: (1) On-peak and off-peak energy rates based on Option B hours and information and assumptions available concurrent with the 2014 IRP and derived using methodology approved in Docket No. E-100, Sub 136
(2) Capacity Cost column provides the installed CT cost with AFUDC
(3) Turbine cost agreed upon in E-100 Sub 136 settlement
(4)Does not incorporate additional considerations used in rate calculation and is subject to change.

[END CONFIDENTIAL]

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

	2013 Actual	2014 Forecast	2015 Forecast
Retail MWh Sales	53,394,590	56,560,699	57,179,101
Wholesale MWh Sales	3,418,816	3,452,964	3,479,686
Total MWh Sales	58,813,405	60,013,663	60,658,787

Note: The MWh sales reported above are those applicable to REPS compliance years 2014 – 2016, and represent actual MWh sales for 2013, and projected MWh sales for 2014 and 2015.

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

	2013 (Actual)	2014 (Projected)	2015 (Projected)	2016 (Projected)
Residential Accts	1,767,364	1,791,660	1,812,814	1,836,120
General Accts	244,295	247,556	250,632	254,045
Industrial Accts	5,218	5,035	4,988	4,942

Note: The number of accounts reported above are those applicable to the cost caps for compliance years 2014 – 2016, and represent the actual number of accounts for year-end 2013, and the projected number of accounts for year-end 2014 through 2016.

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

	2014	2015	2016
Total projected REPS compliance costs	$ 54,130,957	$ 61,096,587	$ 65,967,429
Recovered through the Fuel Rider	$ 36,385,535	$ 40,318,385	$ 41,176,838
Total incremental costs (REPS Rider)	$ 17,745,422	$ 20,778,202	$ 24,790,591
Total including Regulatory Fee	$ 17,768,556	$ 20,805,290	$ 24,822,911
Projected Annual Cost Caps (REPS Rider)	$ 63,070,639	$ 103,084,760	$ 104,218,833

EXHIBIT A

Duke Energy Carolinas, LLC's 2014 REPS Compliance Plan
Duke Energy Carolinas' Renewable Resource Procurement from 3rd Parties
(signed contracts)

[BEGIN CONFIDENTIAL]

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		[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]	5 Years*	[redacted]	[redacted]	[redacted]
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[redacted]	20 Years*	[redacted]	[redacted]	[redacted]
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[redacted]	20 Years	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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Notes:
*indicates bundle purchase of RECs and energy, as opposed to REC-only.

[END CONFIDENTIAL]

EXHIBIT B

Duke Energy Carolinas, LLC's 2014 REPS Compliance Plan
Duke Energy Carolinas, LLC's EE Programs and Projected REPS Impacts

Forecast Annual Energy Efficiency Impacts for the REPS Compliance Planning Period 2014-2016 (MWhs)			
Residential Programs	2014	2015	2016
Residential Energy Assessments	4,929	4,929	4,929
Smart Saver® for Residential Customers	43,063	46,881	47,585
Low Income Energy Efficiency and Weatherization Assistance	1,562	1,562	1,562
Energy Efficiency Education Program for Schools	5,226	5,226	5,716
Residential Retrofit Pilot	-	-	-
Appliance Recycle	16,819	16,819	16,819
Residential Neighborhood Low Income Program	8,362	8,362	8,362
My Home Energy Report	50,032	-	-
New Products	25,000	25,000	25,000
Sub Total	**154,993**	**108,780**	**109,974**
Non Residential Programs	2014	2015	2016
Smart Saver® for Non-Res Customers Lighting	65,275	69,216	72,730
Smart Saver® for Non-Res Customers Motors	5,698	5,983	6,282
Smart Saver® for Non-Res Customers - Other Prescriptive	77	80	84
Smart Saver® for Non-Res Customers - Energy Star Food Svc	1,066	1,369	1,363
Smart Saver® for Non-Res Customers - HVAC	5,934	6,287	6,664
Smart Saver® for Non-Res Customers - Custom Rebate	97,797	100,564	111,204
Smart Energy Now	-	-	-
New Products	25,000	25,000	25,000
Sub Total	**200,847**	**208,499**	**223,327**
Grand Total	**355,840**	**317,279**	**333,301**