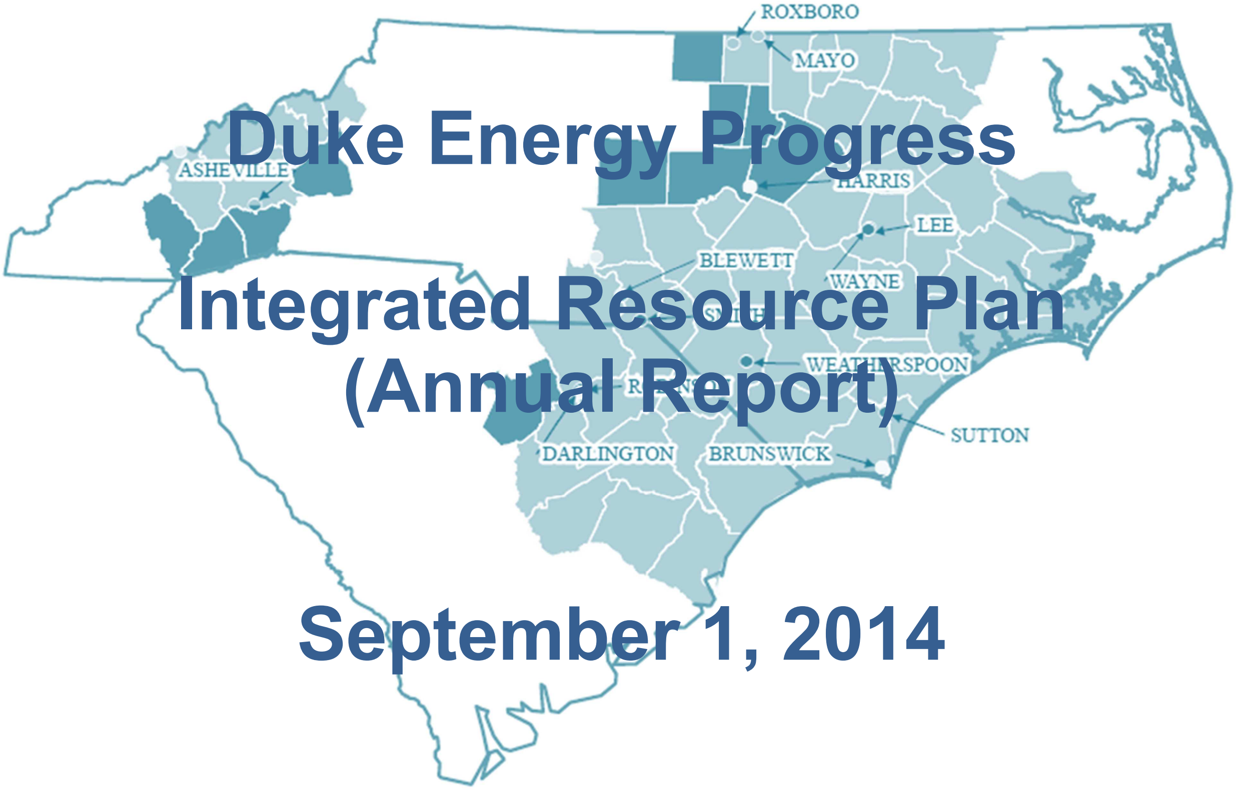
Duke Energy Progress

Integrated Resource Plan (Annual Report)

September 1, 2014



Public

DEP 2014 IRP TABLE OF CONTENTS

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

<u>Overview</u>

For more than a century, Duke Energy Progress (DEP) has provided affordable and reliable electricity to customers in North Carolina (NC) and South Carolina (SC) now totaling more than 1.5 million in number. Each year, as required by the North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC), DEP 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 DEP's entire system.
- Add new resources at the lowest reasonable cost to customers. These resources include energy efficiency programs (EE), demand-side management programs (DSM), renewable resources, nuclear generation and natural gas generation.
- Meet or exceed all Federal, State and local environmental regulations.

<u>The Road Ahead − Determining Customer Electricity Needs 2015 – 2029</u>

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 1.3%. The growth rate is offset by projections for increased EE impacts, reducing the projected growth rate by 0.3% 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 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 0.5%.
- Residential class has a projected growth rate of 1.3%.

In addition to customer growth, plant retirements and expiring purchase 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.

In December of 2013, Sutton Steam Station Units 1 – 3, the last of DEP's coal units that lacked advanced emission controls, were shuttered. Since 2011, DEP has retired 1,600 MW at 12 older coal units in favor of cleaner burning natural gas plants that comply with stringent air, water and waste rules. Over the 15-year planning horizon, the Company will continue to modernize its fleet with the planned retirements of older combustion turbine (CT) units including:

- Sutton CT Units 1, 2A and 2B, located in Wilmington, NC, totaling 61 MW, by 2017
- Darlington CT Units 1 - 11, located in Darlington County, SC, totaling 553 MW by 2020
- Blewett CT Units 1 – 4, located in Lilesville, NC, totaling 52 MW, by 2027
- Weatherspoon CT Units 1 – 4, located in Lumberton, NC, totaling 128 MW, by June 2027

Investments Strategy to Meet New Resource 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:

- Pursue 84-MW Sutton fast start/black start CT in 2017.
- Pursue 126-MW of fast start CT capacity in Asheville, NC, in 2018.
- Consider an 866-MW natural gas combined cycle (CC) in 2020.
- Consider 792-MW of CT capacity in 2021.
- Consider an 866-MW natural gas CC in 2022.
- Consider an 866-MW natural gas CC in 2027.
- Consider 396-MW of CT capacity in 2029.

Nuclear Power

Duke Energy continues to support new nuclear generation as a carbon-free, cost-effective, reliable option within the Company's resource portfolio in a carbon-constrained future. While the 2014 Base Case does not call for the construction of additional self-owned nuclear generation before 2030, it is considered in the IRP's alternative Joint Planning Case. The Joint Planning Case projects shared DEC-DEP ownership of the W.S. Lee Nuclear Facility in 2024.

Under either set of assumptions, nuclear generation continues to be a viable option for economically meeting customer needs and expected environmental regulations.

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. DEP 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 485 MW in 2015 to 889 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.
- Plan for incremental renewables above NC REPS as a result of new supportive legislation in South Carolina and the potential for 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 takes 4 to 5 MWs 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 DEP'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 DEP's 12 EE and DSM programs, successfully increasing customer adoption. The Company is forecasting continued energy savings from both EE and DSM programs through the planning period.

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

Projected EE and DSM Energy and Capacity Savings		
Year	**Energy (MWh)**	**Capacity (MW)**
2015	638,000	945
2029	3,575,000	1,669

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.

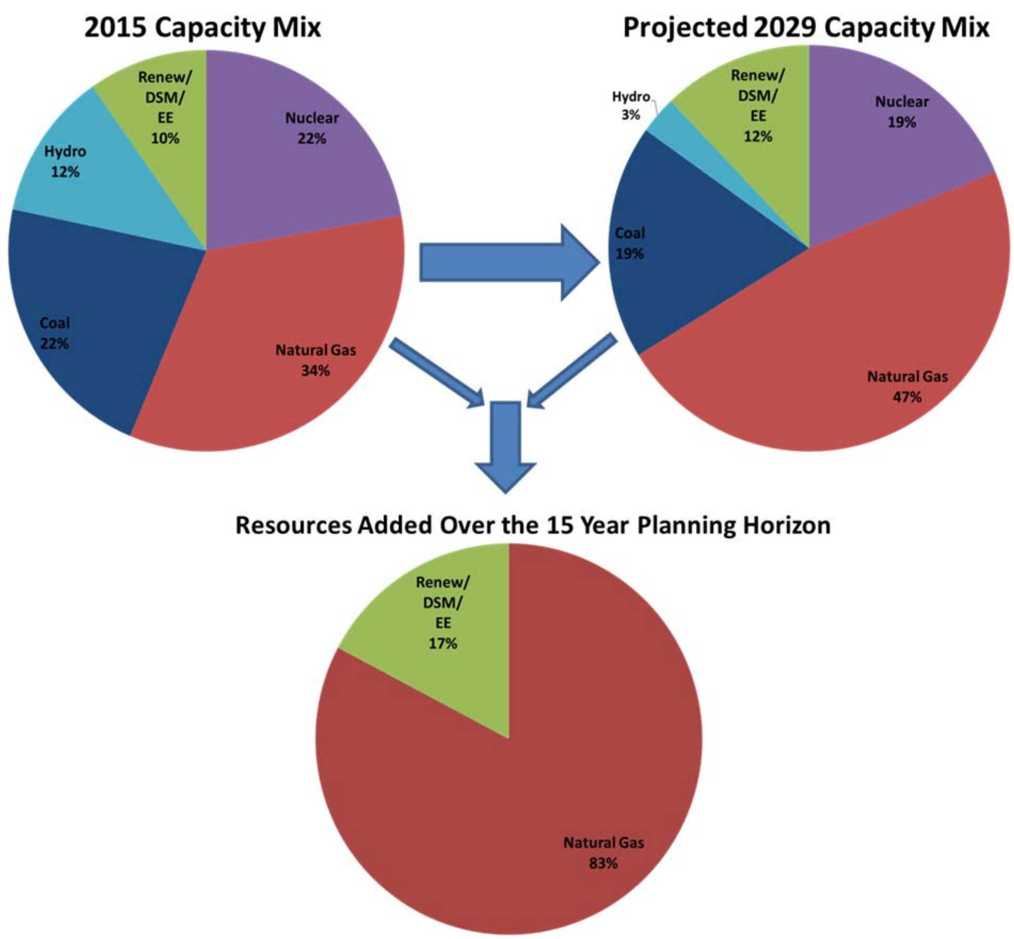
Strong Trend Toward Cleaner, More Environmentally Friendly Generation

When viewed in total, approximately 50% of the energy that DEP 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 half 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. In an effort to comply with 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 17 percent of the Company's projected incremental peak demand needs. The remaining 83 percent of future resources is expected to come from new natural gas 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 plan, 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

DEP's service area covers approximately 34,000 square miles, including a substantial portion of the coastal plain of North Carolina extending from the Piedmont to the Atlantic coast between the Pamlico River and the South Carolina border, the lower Piedmont section of North Carolina, an area in western North Carolina in and around the city of Asheville and an area in the northeastern portion of South Carolina. In addition to retail sales to approximately 1.5 million residential, commercial and industrial customers, the Company also sells wholesale electricity to incorporated municipalities and to public and private utilities.

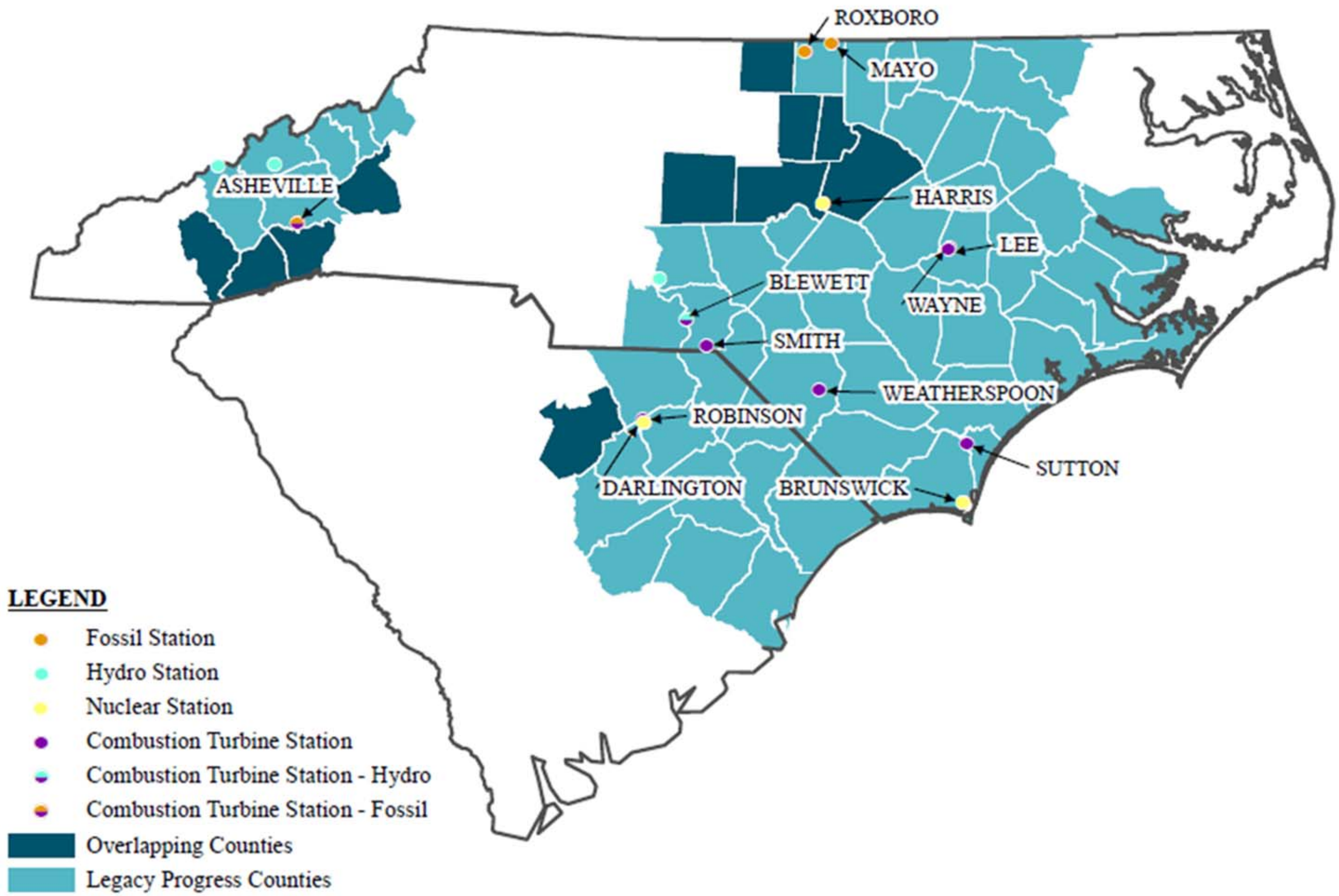
DEP currently meets energy demand, in part, by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:

- Three nuclear generating stations with a combined net capacity of 3,539 MW
- Three coal-fired stations with a combined capacity of 3,536 MW
- Four hydroelectric stations with a combined capacity of 222 MW
- Ten combustion turbine stations including three combined cycle units with a combined capacity of 5,625 MW.

DEP's power delivery system consists of approximately 67,048 miles of distribution lines and 6,244 miles of transmission lines. The transmission system is directly connected to all of the Transmission Operators that surround the DEP service area. There are 42 tie-line circuits connecting with six different Transmission Operators: DEC, PJM, Tennessee Valley Authority, Yadkin, 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), and North American Electric Reliability Corporation (NERC).

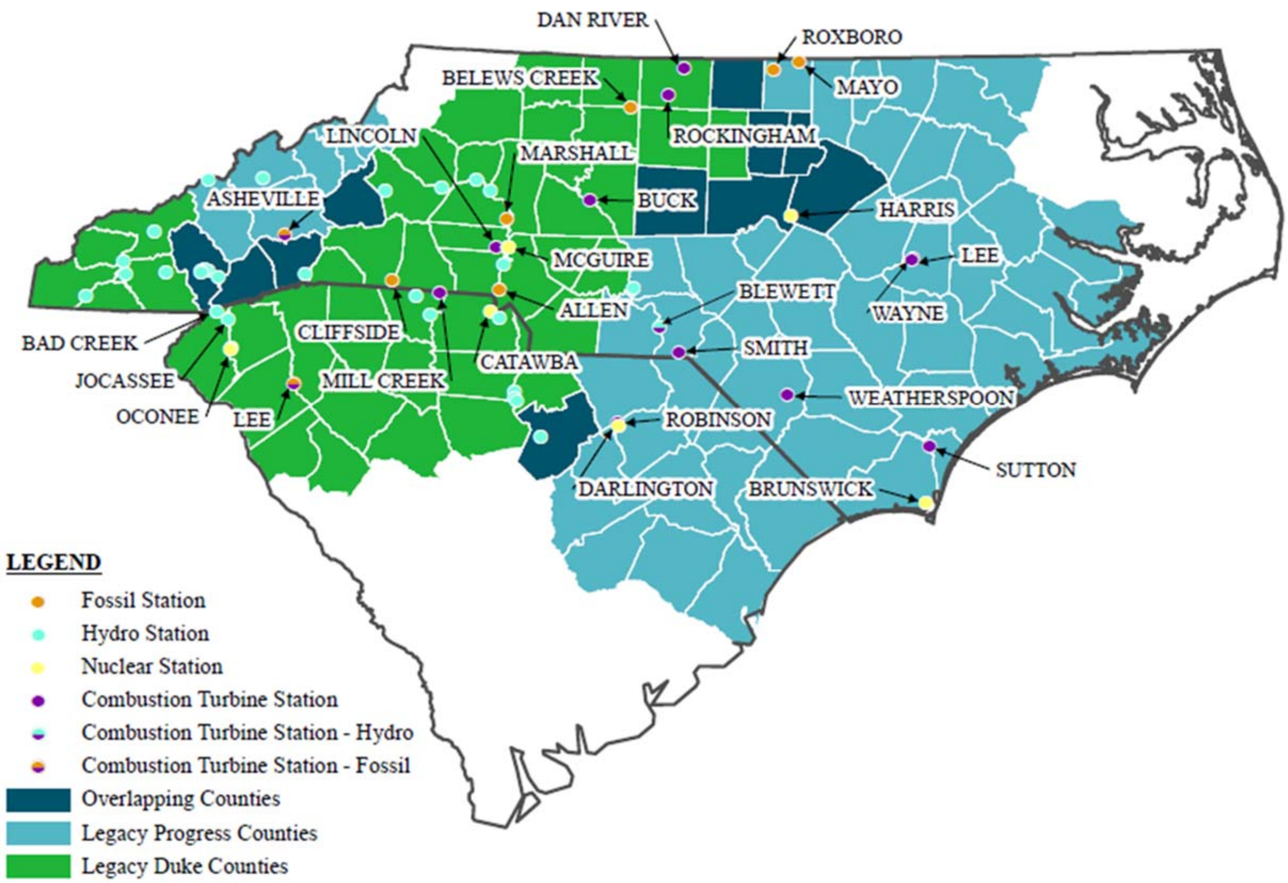
The map on the following page provides a high-level view of the DEP service area.

Chart 2-A Duke Energy Progress Service Area



With the closing of the Duke Energy Corporation and Progress Energy Corporation merger, the service territories for both DEP and DEC 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 DEP and DEC Service Area



3. ELECTRIC LOAD FORECAST

The Duke Energy Progress 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 DEP 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. Regression analysis 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 growth rate of residential in the spring 2014 forecast after all adjustments for utility EE programs, solar and electric vehicles from 2015-2029 is 1.3%.

Commercial electricity usage changes with the level of regional economic activity, such as personal income or commercial employment, and the impact of weather. 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 0.5% over the forecast horizon, after adjustments.

Peak Demand and Energy Forecast

If the impacts of new Duke Energy Progress energy efficiency programs are included, the projected compound annual growth rate for the summer peak demand is 1.4%, while winter peaks are forecasted to grow at a rate of 1.3%. 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 due to the fact that the weather adjusted 2013 actual peak value was lower than projected from the spring 2013 forecast.
Thus, the spring 2014 forecast was growing from a lower starting point. 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	12,924	12,429	65,660
2016	13,097	12,659	66,408
2017	13,267	12,751	67,083
2018	13,453	12,929	67,825
2019	13,646	13,125	68,561
2020	13,824	13,287	69,236
2021	14,007	13,537	69,797
2022	14,197	13,717	70,419
2023	14,400	13,837	71,034
2024	14,613	13,974	71,667
2025	14,817	14,133	72,285
2026	15,018	14,308	72,949
2027	15,266	14,528	73,785
2028	15,496	14,734	74,783
2029	15,726	14,844	75,738

Note: Table 8-C differs from these values due to a 150 MW firm sale to NCEMC through 2024.

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

4. ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT

DEP is committed to making sure electricity remains available, reliable and affordable and that it is produced in an environmentally sound manner and, therefore, DEP 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 2008, DEP 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. DEP'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.

DEP's EE programs encourage customers to save electricity by installing high efficiency measures and/or changing the way they use their existing electrical equipment. DEP 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. DEP will continue to seek Commission approval from state utility commissions to implement EE and DSM programs that are cost-effective and consistent with DEP's forecasted resource needs over the planning horizon. DEP 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. DEP also offers a variety of DSM (or demand response) programs that signal customers to reduce electricity use during select peak hours as specified by the Company. The IRP treats these "dispatchable" types of programs as a resource option that can be dispatched to meet system capacity needs during periods of peak demand.

To better understand the long-term EE savings potential, DEP commissioned a market potential study by Forefront Economics, Inc. in 2012 that estimated the achievable potential for EE on an annual basis over a 20-year forecast period. The results of that 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 near-term program planning forecasts into the long-term achievable potential projections from the 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 DEP's EE and DSM programs. To support this effort, DEP has focused on planning and implementing programs that work well with customer lifestyles, expectations and business needs.

Finally, DEP 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 DEP'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. Grid Modernization related demand response impacts are also discussed in Appendix D.

DEP also prepared a high EE savings projection designed to meet the five year Energy Efficiency Performance Targets set forth in the December 8, 2011 Settlement Agreement in Docket E-2, Sub 998. The savings in this high EE projection are well beyond the levels historically attained by DEP and forecasted in the market potential study. As a result, there is too much uncertainty regarding the possibility of actually realizing that 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 DEP'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 Progress 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 DEP 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, DEP 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 812 MW (nameplate) of rated compliance renewable energy resources will be interconnected to the DEP system by 2021, with that figure growing to approximately 1,150 MW (nameplate) 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 (nameplate or installed capacity) at the time of peak load. In the 2014 IRP, the contribution to summer peak values that were utilized were 44% 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 DEP Base Case Renewables

DEP Renewables									
	MW Contribution to Summer Peak					MW Nameplate			
	Wind	Solar	Biomass/ Hydro	Total		Wind	Solar	Biomass/ Hydro	Total
2015	0	141	136	276		0	319	136	455
2016	0	163	157	319		0	369	157	526
2017	0	174	163	337		0	394	163	558
2018	0	185	130	315		0	419	130	550
2019	0	207	161	368		0	471	161	632
2020	13	228	185	426		100	518	185	803
2021	13	249	146	408		100	566	146	812
2022	13	270	158	441		100	614	158	872
2023	13	291	169	473		100	661	169	930
2024	13	312	171	496		100	709	171	980
2025	13	333	183	529		100	758	183	1040
2026	13	355	187	554		100	806	187	1093
2027	13	374	191	577		100	849	191	1140
2028	13	386	192	590		100	876	192	1168
2029	13	380	186	579		100	864	186	1150

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 DEP Base Case Total Renewables (Compliance & Non-compliance)

DEP Renewables									
	MW Contribution to Summer Peak					MW Nameplate			
	Wind	Solar	Biomass/ Hydro	Total		Wind	Solar	Biomass/ Hydro	Total
2015	0	213	236	449		0	485	236	721
2016	0	235	268	504		0	535	268	803
2017	0	246	274	520		0	560	274	834
2018	0	257	241	498		0	584	241	825
2019	0	279	272	551		0	635	272	907
2020	13	300	295	608		100	683	295	1078
2021	13	321	167	501		100	730	167	997
2022	13	342	177	532		100	776	177	1054
2023	13	363	188	564		100	824	188	1112
2024	13	384	190	587		100	872	190	1162
2025	13	405	202	620		100	921	202	1222
2026	13	426	206	645		100	969	206	1275
2027	13	443	210	666		100	1007	210	1317
2028	13	427	207	647		100	969	207	1277
2029	13	391	198	602		100	889	198	1187

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 DEP's 2013 IRP.

DEP 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 DEP's compliance efforts beyond the solar set-aside minimum threshold for NC REPS and in the corresponding compliance for South Carolina.

DEP 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 of that reliance will likely vary commensurately with changes to supporting policies and prevailing market prices. The Company has also 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.

The Company expects biomass resources to continue to play an important 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. DEP will continue to evaluate hydro opportunities on a case-by-case basis and will include it as a resource option, if appropriate.

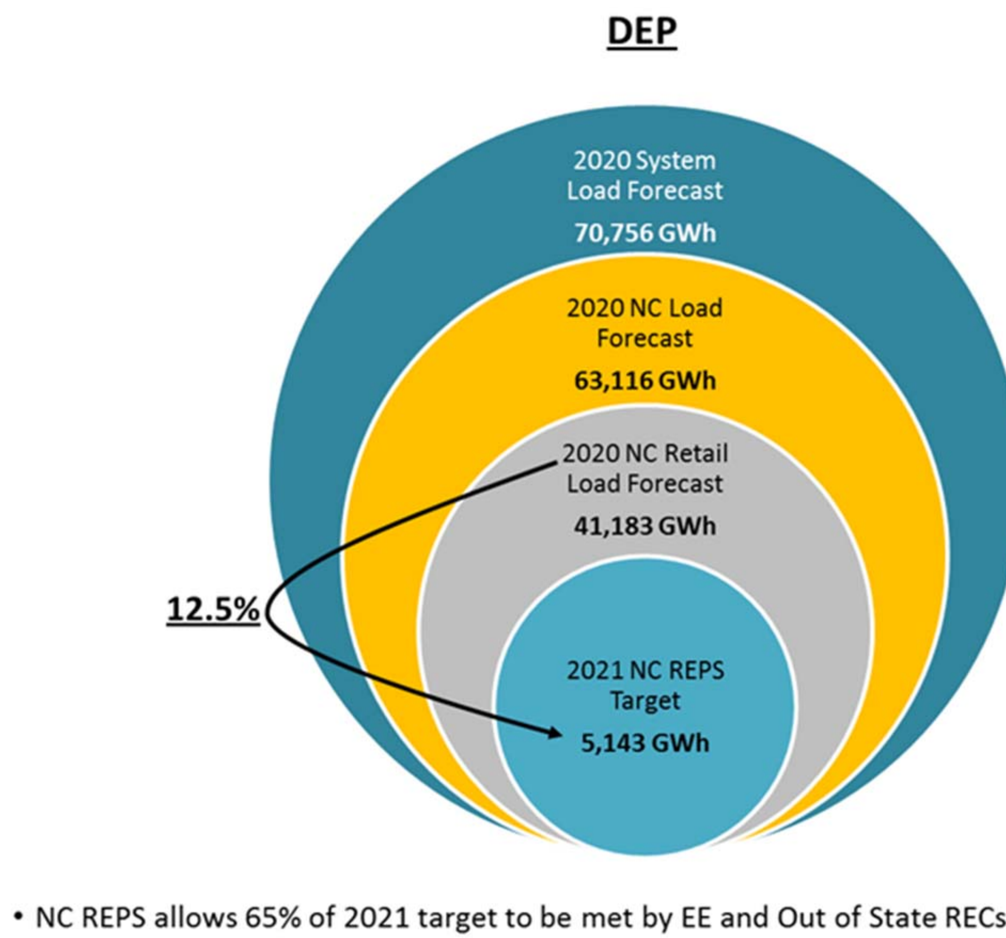
In general, the Company expects a mix of resources will ultimately be used for meeting renewable targets, with the specifics of that mix determined in large part by policy developments over the coming five to ten years. Costs for all the resources discussed above are highly dependent upon future subsidies, 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, carbon reduction mandates, low fuel costs, continuation of renewable subsidies and/or stronger renewable energy mandates. Specifically, these portfolios assume a requirement for DEP 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 1,828 MW nameplate (746 MW contribution to peak) in DEP 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 DEP High Renewables (Compliance and Non-compliance Purchases)

DEP Renewables									
	MW Contribution to Summer Peak					MW Nameplate			
	Wind	Solar	Biomass/ Hydro	Total		Wind	Solar	Biomass/ Hydro	Total
2015	0	213	236	449		0	485	236	721
2016	0	235	268	504		0	535	268	803
2017	0	246	274	520		0	560	274	834
2018	0	257	241	498		0	584	241	825
2019	0	279	272	551		0	635	272	907
2020	15	372	295	683		119	847	295	1261
2021	18	466	167	650		138	1058	167	1363
2022	20	558	177	755		157	1268	177	1602
2023	23	651	188	862		176	1480	188	1844
2024	25	744	190	960		195	1692	190	2076
2025	28	838	202	1067		213	1904	202	2319
2026	30	931	206	1167		232	2116	206	2554
2027	33	1020	210	1262		251	2318	210	2779
2028	35	1076	207	1318		270	2444	207	2922
2029	38	1112	198	1348		289	2527	198	3015

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 Progress 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

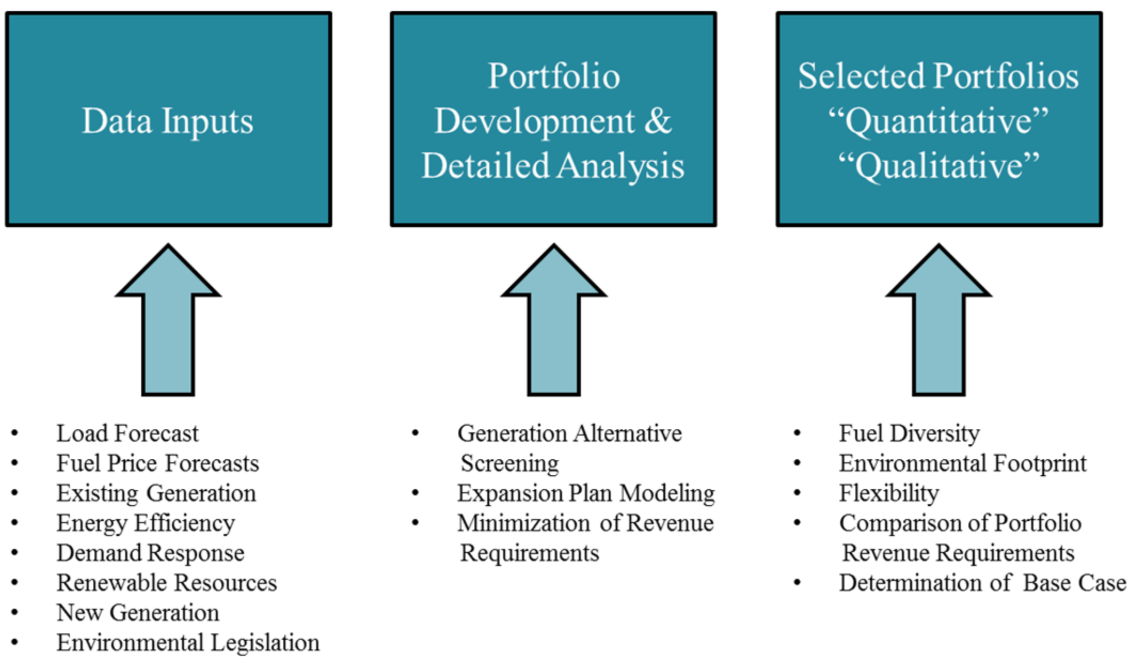
DEP's resource plan reflects reserve margins ranging from 15 to 21%. Reserves projected in DEP's IRP meet the minimum planning reserve margin target and thus satisfy the one day in 10 years LOLE criterion. The projected reserve margin exceeds the minimum 14.5% target by 3% or more in 2015-2017 primarily due to a decrease in the load forecast. Projected reserve margins also exceed the target by 3% or more in 2022, 2023, and 2027 as a result of the economic addition of large combined-cycle facilities in years 2022 and 2027. 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 DEP'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 DEP's customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, DEP 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 DEP considers the non-firm energy purchases and sales associated with the Joint Dispatch Agreement (JDA) with DEC in the development of its independent Base Case and four alternative scenarios to be discussed later in this chapter and in Appendix A.

Figure 8-A represents a simplified overview of the resource planning process. 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 is examined in more detail in the appendices.

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

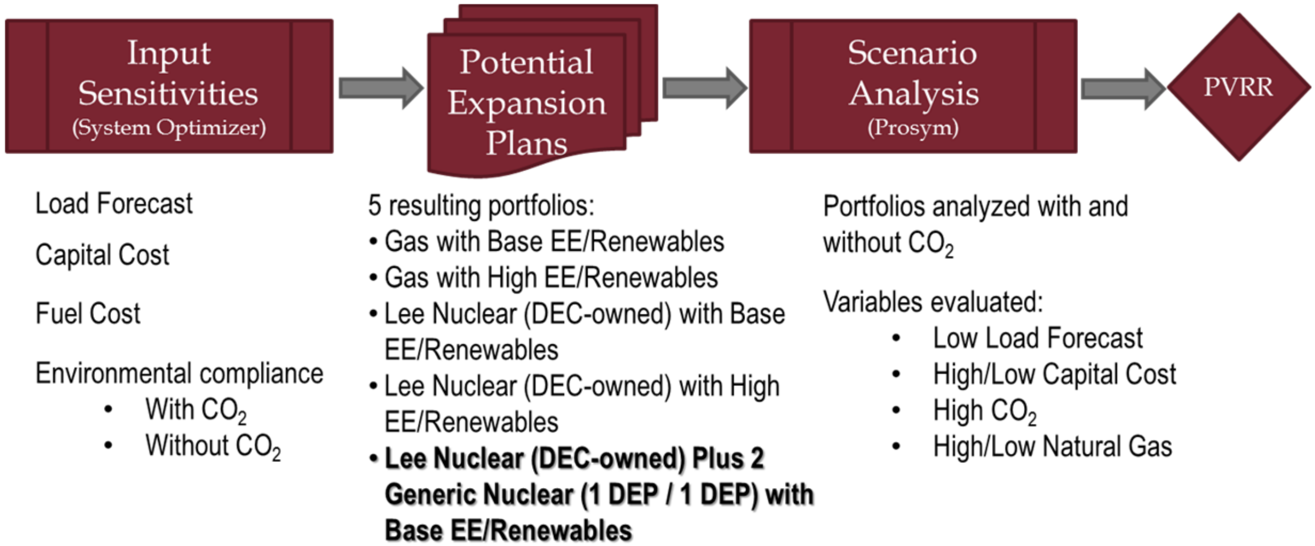
Generation Alternative Screening

DEP 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 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 followed in 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 DEP 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 DEP system, the potential benefits of sharing capacity within DEP and DEC 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 Lee Nuclear (DEC-owned portfolio, and 3) Lee Nuclear (DEC-owned) plus two additional nuclear units (1 DEP / 1 DEC) 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	3	2
2	Lee Nuclear (DEC-owned) with Base EE/Renewables	2	1
3	Lee Nuclear (DEC-owned) + 2 New Nuclear (1 DEC/1 DEP) with Base EE/Renewables	1 - Base Case	3
4	No Nuclear with High EE/Renewables	5	5
5	Lee Nuclear (DEC-owned) with High EE/Renewables	4	4

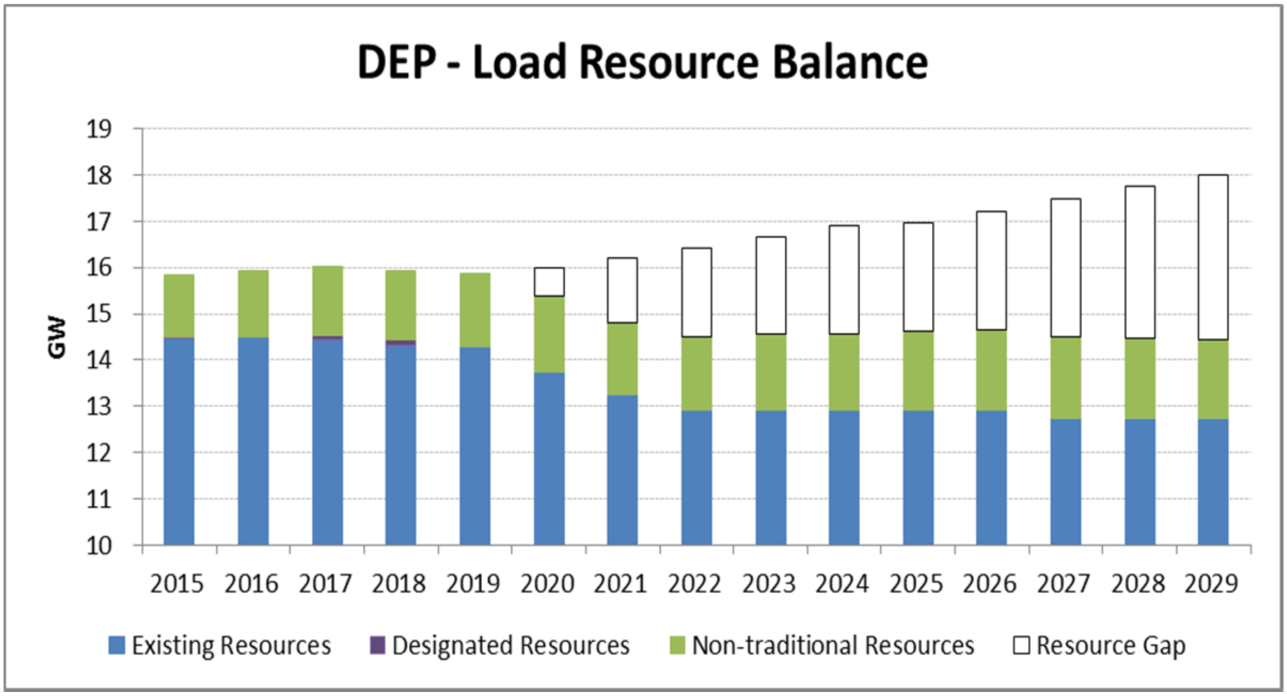
Based on the PVRR Rankings, the robustness of the portfolio, and the belief that there will be some type of carbon legislation in the future, Portfolio #3 With CO_2 was selected as the Base Case in the 2014 IRP.

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 DEP 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 DEP 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	619	1,409	1,918
Year	2023	2024	2025	2026	2027	2028	2029	
Resource Need	2,113	2,328	2,349	2,549	2,985	3,261	3,569	

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

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

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

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Load Forecast															
1 Duke System Peak	12,983	13,198	13,406	13,626	13,856	14,075	14,303	14,539	14,786	15,041	15,284	15,517	15,793	16,046	16,298
2 Firm Sale	150	150	150	150	150	150	150	150	150	150	0	0	0	0	0
3 Cumulative New EE Programs	(60)	(101)	(139)	(173)	(210)	(252)	(297)	(342)	(386)	(428)	(467)	(499)	(527)	(549)	(571)
4 Adjusted Duke System Peak	**13,074**	**13,247**	**13,417**	**13,603**	**13,796**	**13,974**	**14,157**	**14,347**	**14,550**	**14,763**	**14,817**	**15,018**	**15,266**	**15,496**	**15,726**
Existing and Designated Resources															
5 Generating Capacity	12,779	12,799	12,799	12,836	12,973	12,973	12,567	12,567	12,567	12,567	12,567	12,567	12,567	12,387	12,387
6 Designated Additions / Uprates	20	0	98	137	0	0	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	0	(61)	0	0	(406)	0	0	0	0	0	0	(180)	0	0
8 Cumulative Generating Capacity	**12,799**	**12,799**	**12,836**	**12,973**	**12,973**	**12,567**	**12,567**	**12,567**	**12,567**	**12,567**	**12,567**	**12,567**	**12,387**	**12,387**	**12,387**
Purchase Contracts															
9 Cumulative Purchase Contracts	**1,865**	**1,876**	**1,875**	**1,655**	**1,487**	**1,342**	**772**	**441**	**441**	**441**	**441**	**441**	**439**	**406**	**373**
Non-Compliance Renewable Purchases	173	185	184	183	183	183	93	91	91	91	91	91	89	56	23
Non-Renewables Purchases	1,692	1,692	1,692	1,472	1,304	1,159	679	350	350	350	350	350	350	350	350
Undesignated Future Resources															
10 Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Combined Cycle	0	0	0	0	0	866	0	866	0	0	0	0	866	0	0
12 Combustion Turbine				0	126	0	792	0	0	0	0	0	0	0	396
Renewables															
13 Cumulative Renewables Capacity	276	319	337	315	368	426	408	441	473	496	529	554	577	590	579
14 Cumulative Production Capacity	**14,940**	**14,994**	**15,048**	**14,943**	**14,954**	**15,326**	**15,531**	**16,099**	**16,131**	**16,154**	**16,187**	**16,212**	**16,919**	**16,900**	**17,251**
Demand Side Management (DSM)															
15 Cumulative DSM Capacity	**885**	**925**	**966**	**1,002**	**1,036**	**1,046**	**1,053**	**1,060**	**1,066**	**1,073**	**1,079**	**1,086**	**1,092**	**1,098**	**1,098**
16 Cumulative Capacity w/ DSM	**15,826**	**15,920**	**16,014**	**15,945**	**15,990**	**16,372**	**16,584**	**17,159**	**17,197**	**17,227**	**17,266**	**17,298**	**18,011**	**17,998**	**18,350**
Reserves w/ DSM															
17 Generating Reserves	2,752	2,672	2,598	2,342	2,194	2,399	2,427	2,812	2,647	2,463	2,449	2,279	2,745	2,502	2,623
18 % Reserve Margin	**21.1%**	**20.2%**	**19.4%**	**17.2%**	**15.9%**	**17.2%**	**17.1%**	**19.6%**	**18.2%**	**16.7%**	**16.5%**	**15.2%**	**18.0%**	**16.1%**	**16.7%**

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

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

	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29
Load Forecast															
1 Duke System Peak	12,468	12,729	12,849	13,051	13,287	13,481	13,765	13,980	14,135	14,303	14,493	14,693	14,935	15,158	15,285
2 Firm Sale	150	150	150	150	150	150	150	150	150	150	0	0	0	0	0
3 Cumulative New EE Programs	(39)	(70)	(98)	(123)	(162)	(194)	(229)	(263)	(297)	(330)	(360)	(385)	(407)	(424)	(441)
4 Adjusted Duke System Peak	**12,579**	**12,809**	**12,901**	**13,079**	**13,275**	**13,437**	**13,687**	**13,867**	**13,987**	**14,124**	**14,133**	**14,308**	**14,528**	**14,734**	**14,844**
Existing and Designated Resources															
5 Generating Capacity	14,057	13,866	13,886	13,900	13,908	14,045	14,045	13,513	13,513	13,513	13,513	13,513	13,513	13,513	13,281
6 Designated Additions / Uprates	4	20	14	84	137	0	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	(195)	0	0	(76)	0	0	(532)	0	0	0	0	0	0	(232)	0
8 Cumulative Generating Capacity	**13,866**	**13,886**	**13,900**	**13,908**	**14,045**	**14,045**	**13,513**	**13,513**	**13,513**	**13,513**	**13,513**	**13,513**	**13,513**	**13,281**	**13,281**
Purchase Contracts															
9 Cumulative Purchase Contracts	**1,954**	**1,945**	**1,957**	**1,956**	**1,695**	**1,527**	**1,382**	**791**	**409**	**409**	**409**	**409**	**409**	**408**	**399**
Non-Compliance Renewable Purchas	124	115	127	126	125	125	125	35	34	34	34	34	34	33	24
Non-Renewables Purchases	1,830	1,830	1,830	1,830	1,570	1,402	1,257	756	375	375	375	375	375	375	375
Undesignated Future Resources															
10 Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Combined Cycle	0	0	0	0	0	0	907	0	907	0	0	0	0	907	0
12 Combustion Turbine	0	0	0	0	147	0	0	872	0	0	0	0	0	0	0
Renewables															
13 **Cumulative Renewables Capacity**	176	165	190	199	168	204	274	240	256	272	278	294	302	310	314
14 Cumulative Production Capacity	**15,996**	**15,996**	**16,046**	**16,063**	**16,055**	**15,923**	**16,223**	**16,470**	**17,011**	**17,026**	**17,033**	**17,049**	**17,057**	**17,739**	**17,733**
Demand Side Management (DSM)															
15 Cumulative DSM Capacity	**573**	**575**	**586**	**602**	**616**	**629**	**642**	**649**	**657**	**664**	**671**	**679**	**686**	**692**	**698**
16 Cumulative Capacity w/ DSM	**16,569**	**16,571**	**16,633**	**16,665**	**16,672**	**16,552**	**16,865**	**17,120**	**17,668**	**17,690**	**17,704**	**17,727**	**17,743**	**18,431**	**18,432**
Reserves w/ DSM															
17 Generating Reserves	3,990	3,762	3,732	3,586	3,397	3,115	3,179	3,253	3,681	3,566	3,571	3,419	3,214	3,697	3,588
18 % Reserve Margin	**31.7%**	**29.4%**	**28.9%**	**27.4%**	**25.6%**	**23.2%**	**23.2%**	**23.5%**	**26.3%**	**25.2%**	**25.3%**	**23.9%**	**22.1%**	**25.1%**	**24.2%**

DEP - 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 table. All values are MW except where shown as a Percent.

1. Planning is done for the peak demand for the Duke Energy Progress System.

2. Firm sale of 150 MW through 2024.

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

4. Peak load adjusted for FERC mitigation sale, firm sales, and cumulative energy efficiency .

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

   Includes total unit capacity of jointly owned units.

6. Capacity Additions include:

   Planned nuclear uprates totalling 38 MW in the 2014-2017 timeframe.

   Planned combined cycle uprates totalling 137 MW in 2018.

   Expected replacement of Sutton CT units 1, 2A and 2B with an 84 MW combustion turbine in 2017.

7. Planned Retirements include:
   Sutton CT Units 1, 2A and 2B in 2017 (61 MW)
   Darlington CT Units 1-11 by 2020 (553 MW)
   Blewett CT Units 1-4 and Weatherspoon CT units 1-4 in 2027 (180 MW)

8. Sum of lines 5 through 7.

9. Cumulative Purchase Contracts have several components:

   Purchased capacity from PURPA Qualifying Facilities, Anson and Hamlet CT tolling,

   Butler Warner purchase, Southern CC purchase, and Broad River CT purchase.

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

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

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.

    No new nuclear resources were selected in the Base Case in the 15 year study period.

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, 2022 and 2027.

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 126 MW of combustion turbine capacity in 2019.

    Addition of 792 MW of combustion turbine capacity in 2021.

    Addition of 396 MW of combustion turbine capacity in 2029.

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

    Also include compliance resources for South Carolina (discussed in Chapter 5).

14. Sum of lines 8 through 13.

15. Cumulative Demand Side Management 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:

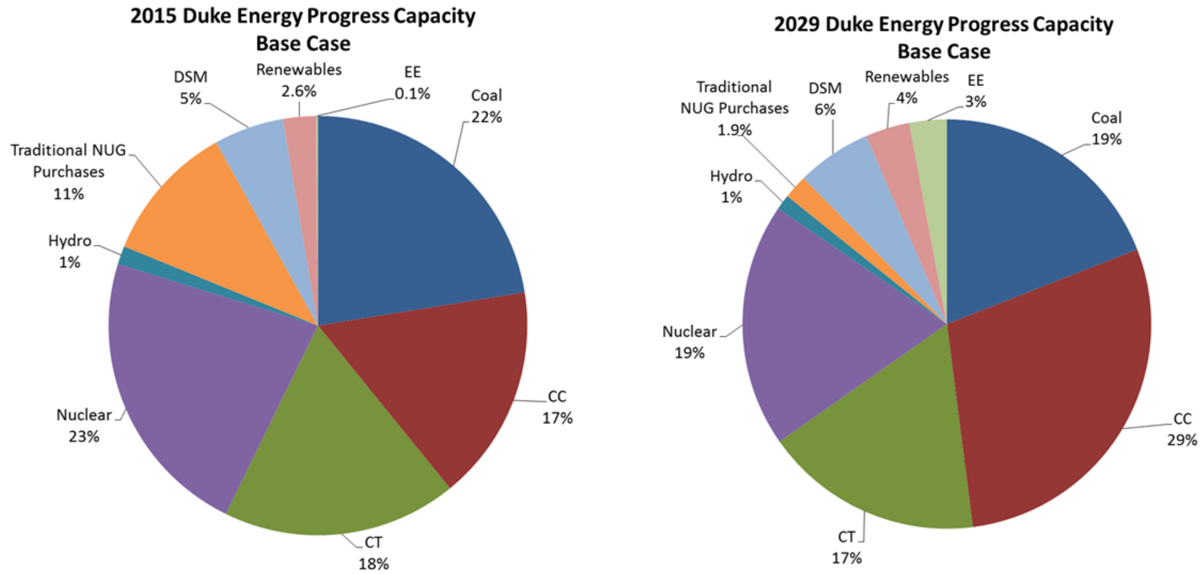
Table 8-D DEP Base Case

Duke Energy Progress Resource Plan (1) Base Case				
Year	**Resource**		**MW**	
2015	Nuclear Uprates		20	
2016	-		-	
2017	Sutton Replacement CTs	Nuclear Uprates	84	14
2018	CC Uprates		137	
2019	Fast Start CT		126	
2020	New CC		866	
2021	New CT		792	
2022	New CC		866	
2023	-		-	
2024	-		-	
2025	-		-	
2026	-		-	
2027	New CC		866	
2028	-		-	
2029	New CT		396	

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

The following charts illustrate both the current and forecasted capacity by fuel type for the DEP system, as projected by the Base Case. As demonstrated in Chart 8-B, the capacity mix for the DEP system changes with the passage of time. In 2029, the Base Case projects that DEP will have a smaller reliance on coal, nuclear and purchases and a higher reliance on gas-fired resources, renewable resources and EE as compared to the current state.

Chart 8-B Duke Energy Progress 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.

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.

[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 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

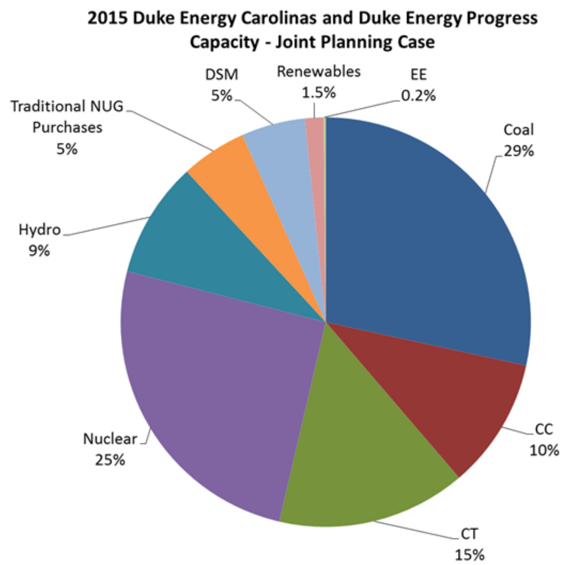
Delays CC 1 year

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 DEP and DEC 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 reliance on coal resources decrease. The Companies' renewable energy and EE impacts continue to grow over time, as 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 CAPACITY CHARTS
(DEC and DEP Joint Planning Case)



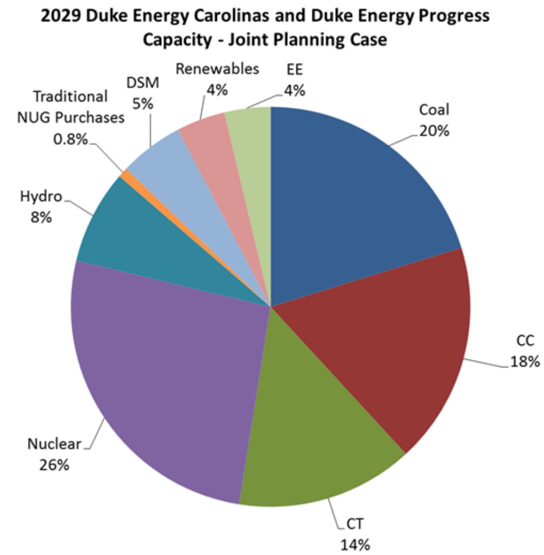
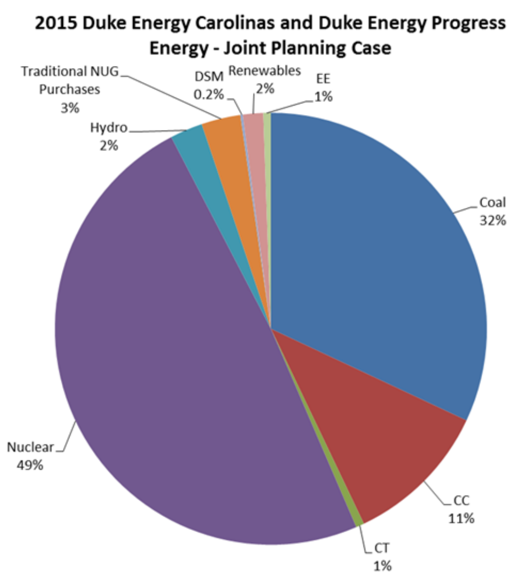
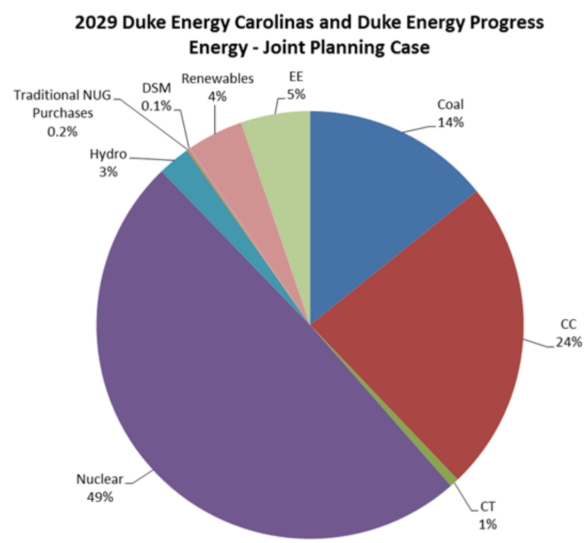


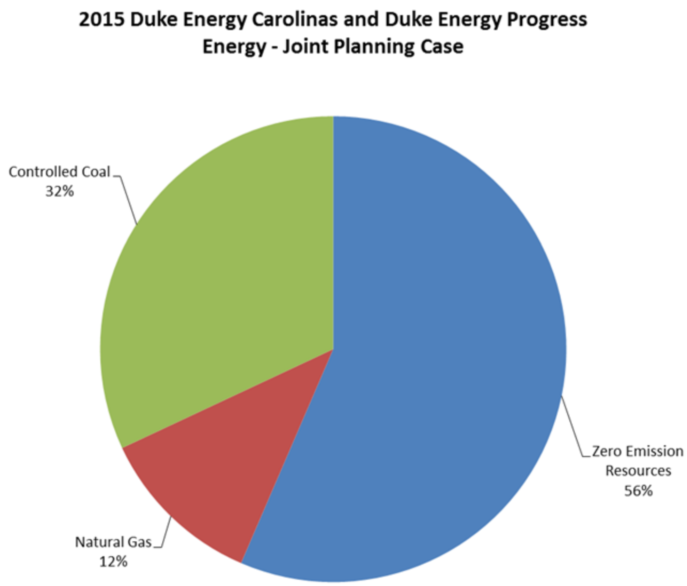
Chart 8-D ENERGY CHARTS
(DEC and DEP Joint Planning Case)

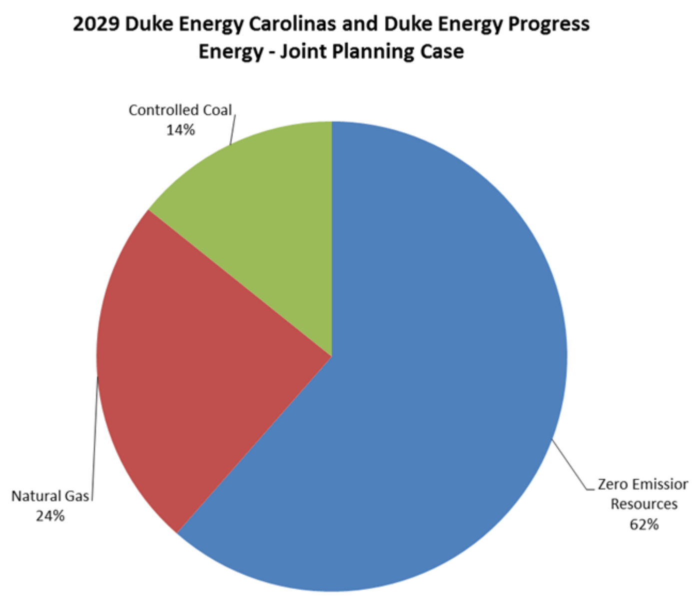




The following charts group the energy based upon the emission impacts of the resources in the DEC and DEP Joint Planning Case. The Zero Emission category includes nuclear, hydro, renewables, EE and DSM resources. The Natural Gas category includes clean burning gas CCs and CTs. It must be noted that the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

Chart 8-E DEC and DEP Energy by Emission Impacts – 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 DEP 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 work to develop and implement additional cost-effective EE and DSM products and services. Since the last biennial IRP, DEP has implemented the following new program offerings: Residential New Construction Program, Energy Efficient Lighting Program and Small Business Energy Saver Program.

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

Continued Focus on Renewable Energy Resources:

DEP is committed to full compliance with NC REPS in North Carolina and to explore least cost options to add renewable resources in South Carolina pursuant to supportive distributed energy resource legislation in that state. 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, DEP will likely obtain additional solar generation on its system. In addition, the Company continues to procure additional renewable resources when economically viable. DEP is also pursuing the addition of new utility-owned solar on the DEP system.

DEP 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.

Addition of Clean Natural Gas Resources:

- Pursue the addition of fast start CT generation in the western region in the 2019 timeframe.

- Continue to evaluate older CTs on the DEP system. The Company is evaluating the condition and economic viability of the older CTs on the system. In doing so, DEP is preparing for the potential retirement of these units. This includes determining the type of resources needed to reliably replace these units to maintain a minimum planning reserve margin.

    - Sutton Units 1, 2A and 2B (61 MW) are planned for retirement in 2017 and are proposed to be replaced with two LM6000 CT units.

- Take actions to ensure capacity needs beginning in 2020 are met. In addition to seeking to meet the Company's EE and DSM goals and meeting the Company's NC REPS requirements, actions to secure additional capacity may include purchased power or Company-owned generation. The 2014 IRP projects that the best resource to meet this demand is a combined cycle unit.

Continued Focus on Environmental Compliance:

- Retire older coal generation. As of December 2013, all of DEP's older, un-scrubbed coal units have been retired. DEP has retired 1,600 MW of older coal units in total since 2011.

- 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 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 reference plan 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 DEP Short-Term Action Plan

Duke Energy Progress Short-Term Action Plan							
			Compliance Renewable Resources (Cumulative Nameplate MW)				
Year	Retirements[1]	Additions[2]	Wind [3]	Solar [3]	Biomass/Hydro	EE	DSM [4]
2014	147 MW Darlington CT [5] (Units 4, 6, 11)						
2015		20 MW Nuc Uprate	0	319	136	60	885
2016			0	369	157	101	925
2017	61 MW Sutton CT (Units 1, 2A, 2B)	84 MW Sutton CT Repl 14 MW Nuc Uprate	0	394	163	139	966
2018		137 MW CC Uprate	0	419	130	173	1002
2019		126 MW CT	0	471	161	210	1036

Notes:

(1) Sutton Units 1-3 coal retirements in December 2013.

(2) Includes 34 MW of nuclear uprates and 137 MW of CC uprates.

(3) Capacity is shown in nameplate ratings. For planning purposes, wind presents a 13% contribution to peak and solar has a 44% contribution to peak.

(4) Includes impacts of grid modernization.

(5) Darlington 4, 6 & 11 assumed offline 1/2014 and assumed to retire for planning purposes.

DEP Request for Proposal (RFP) Activity

Supply-Side

No supply-side RFPs have been issued since the filing of DEP's 2013 IRP.

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 DE 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; 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 DEP and DEC independently. However, an additional case representative of jointly planning future capacity on a DEP/DEC 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% percent 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 older CTs in the 2015 to 2025 timeframe will be necessary. The 2014 IRP includes those retirements as described below:

    - Sutton 1, 2A and 2B in 2017 (61 MW);
    - Darlington 1 – 11 by 2020 (553 MW);
    - Blewett 1 – 4 in 2027 (52 MW); and
    - Weatherspoon 1 – 4 in 2027 (128 MW)

- Nuclear units are expected to be uprated by 34 MW before 2018.
- Air inlet chillers will be added at Lee CC and Sutton CC in 2018, increasing their combined capacity by a total of 137 MW.
- 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

Supply-Side

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

- Baseload – 2 x 1,117 MW Nuclear units (AP1000)
- Baseload – 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
- Peaking – 84 MW – 2 x LM 6000PC fast start, black start capable CTs
- Peaking – 126 MW 3 x LM 6000PC fast start, black start capable CTs
- Renewable – 150 MW – On-shore Wind
- Renewable – 25 MW – Solar PV

Energy Efficiency and Demand-Side Management

EE and DSM programs continue to be an important part of Duke Energy Progress' 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 2012 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 are 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 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, Asheville Units 1 and 2 and Roxboro Units 1 and 2 Steam Units were retired outside the planning window in 2031 and 2032, respectively.
    - Nuclear assets – Currently nuclear sites are licensed for 40 years with a 20 year license extension beyond that. To date, no nuclear units in the United States have received a license extension beyond 60 years. Robinson Nuclear Station's current operating license has been extended to 60 years and expires in 2030. For the purpose of this IRP, the Robinson Station is assumed to retire in 2030.
    - Combustion Turbines - A condition assessment was performed for the older CTs in the DEP system. It was determined that the Sutton CTs need to be retired by 2017 and Darlington Units 1 through 11 by 2020. Due to reliability concerns, Darlington Units 4, 6, and 11 are not counted on to contribute capacity to the DEP system throughout the planning horizon. The Blewett and Weatherspoon CTs are in better condition and have better access to spare parts and are shown to be retired in 2027.

- 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 SO to select four nuclear units for the combined DEC/DEP system. The Company restricted placement of these units to three in DEC's territory (Lee Nuclear Station plus one additional generic unit) and one generic unit in DEP's territory.

- Allowed SO to select two nuclear units. These units represent Lee Nuclear Station and are only located in the DEC territory.

- 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 9.1% 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

- 2017 - A condition assessment was performed for the older CTs in the DEP system. It was determined that the Sutton CTs should be retired as soon as reasonably possible. The 2014 IRP assumes replacement of the existing Sutton CTs with two LM6000 dual-fueled, fast start, black start CTs totaling 84 MW. The fast start and black start capabilities of the new CTs are vital to provide voltage support for the Brunswick Nuclear plant and the surrounding Wilmington area.

- 2019 – Additional fast start generation capacity is projected to be needed in the Asheville area in the 2019 timeframe if the electrical transmission constraints into the region are not addressed. There is currently a project under consideration to bring additional transmission into the Asheville area that could eliminate the need for additional fast start CTs. However, until this project is approved for planning purposes three LM6000 dual-fueled CTs totaling 127 MW are included in this resource plan.

- 2020 - The first resource need in DEP other than the fast start CTs listed above is in 2020. Combined cycle generation was selected optimally for the With CO_2 Scenario and multiple sensitivities. A combined cycle resource was also selected in the No CO_2 Scenario if gas prices were to trend lower.

New Nuclear Selection – In the With CO_2 Scenario, four new nuclear units were selected in the DEC and DEP IRPs. The Lee Nuclear facility in DEC was selected in the 2024 to 2030 timeframe and two generic nuclear units were selected in the 2035 timeframe, one in DEP and one in DEC. New nuclear resources were 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 in instead of CTs.

High EE and Renewables – The first resource need, other than renewables and the near term CT needs, remains in 2020 in both the No CO_2 and With CO_2 Scenarios. 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.

<u>*Portfolio 1 (No Nuclear, Base EE/Renewables)*</u>
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.

<u>*Portfolio 2 (Lee Nuclear (DEC-owned), Base EE/Renewables)*</u>
This portfolio was developed to simulate a future where Lee Nuclear Station is constructed on the DEC system and is the only new nuclear generation installed in the 2024 to 2034 timeframe with base EE and renewable assumptions.

<u>*Portfolio 3 (Lee Nuclear (DEC-owned) + 2 New Nuclear (1 DEC/1 DEP), Base EE / Renewables)*</u>
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.

<u>*Portfolio 4 (No Nuclear, High EE/Renewables)*</u>
This portfolio was developed if nuclear is not available as a resource option going forward with the assumption of aspirational EE and high renewables.

<u>*Portfolio 5 (Lee Nuclear, High EE/Renewables)*</u>
This portfolio was developed if 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 Progress Portfolio Summary Plans

Duke Energy Progress - Portfolios										
DEP	P1		P2		P3		P4		P5	
Year	Tech	MW	Tech	MW	Tech	MW	Tech	MW	Tech	MW
2020	CC	866	CC	866	CC	866	CC	866	CC	866
2021	CT	792	CT	792	CT	792	CT	792	CT	792
2022	CC	866	CC	866	CC	866				
2023										
2024										
2025										
2026										
2027	CC	866	CC	866	CC	866	CT	396	CT	396
2028										
2029	CT	396	CT	396	CT	396	CC	866	CC	866
2030	CC	866	CC	866	CC	866	CT	792	CT	792
2031	CC	866	CC	866	CC	866				
	CT	792	CT	792						
2032	CC	866	CC	866	NUC	1,117	CC	1,732	CC	1,732
2033					CT	792				
2034	CT	198	CT	198						
Total										
	CC	5,196	CC	5,196	CC	4,330	CC	3,464	CC	3,464
	CT	2,178	CT	2,178	CT	1,980	CT	1,980	CT	1,980
	NUC	-	NUC	-	NUC	1,117	NUC	-	NUC	-
Total		7,374		7,374		7,427		5,444		5,444

Table A-2 DEP Renewables Summary

DEP Renewables									
Portfolios 1,2 & 3					Portfolios 4&5				
MW Nameplate					MW Nameplate				
	Wind	Solar	Biomass/ Hydro	Total		Wind	Solar	Biomass/ Hydro	Total
2015	0	485	236	721	2015	0	485	236	721
2016	0	535	268	803	2016	0	535	268	803
2017	0	560	274	834	2017	0	560	274	834
2018	0	584	241	825	2018	0	584	241	825
2019	0	635	272	907	2019	0	635	272	907
2020	100	683	295	1078	2020	119	847	295	1261
2021	100	730	167	997	2021	138	1058	167	1363
2022	100	776	177	1054	2022	157	1268	177	1602
2023	100	824	188	1112	2023	176	1480	188	1844
2024	100	872	190	1162	2024	195	1692	190	2076
2025	100	921	202	1222	2025	213	1904	202	2319
2026	100	969	206	1275	2026	232	2116	206	2554
2027	100	1007	210	1317	2027	251	2318	210	2779
2028	100	969	207	1277	2028	270	2444	207	2922
2029	100	889	198	1187	2029	289	2527	198	3015

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[2].

Table A-3 Delta PVRR for All Portfolios

Delta Costs for DEP 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	$ 0.15	$ 0.68	$ (0.37)	$ 0.97	$ (1.74)	$ (1.27)	$ (2.23)
Portfolio 2	$ 0.26	$ 0.77	$ (0.25)	$ 1.08	$ (1.67)	$ (1.21)	$ (2.14)
Portfolio 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Portfolio 4	$ 1.90	$ 1.63	$ 2.22	$ 1.74	$ 2.46	$ 2.12	$ 2.77
Portfolio 5	$ 1.97	$ 1.69	$ 2.29	$ 1.79	$ 2.63	$ 2.29	$ 2.96
Note: Positive values indicate Portfolio 3 is lower cost; Negative values indicate Portfolio 3 is higher cost							

[2] 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.

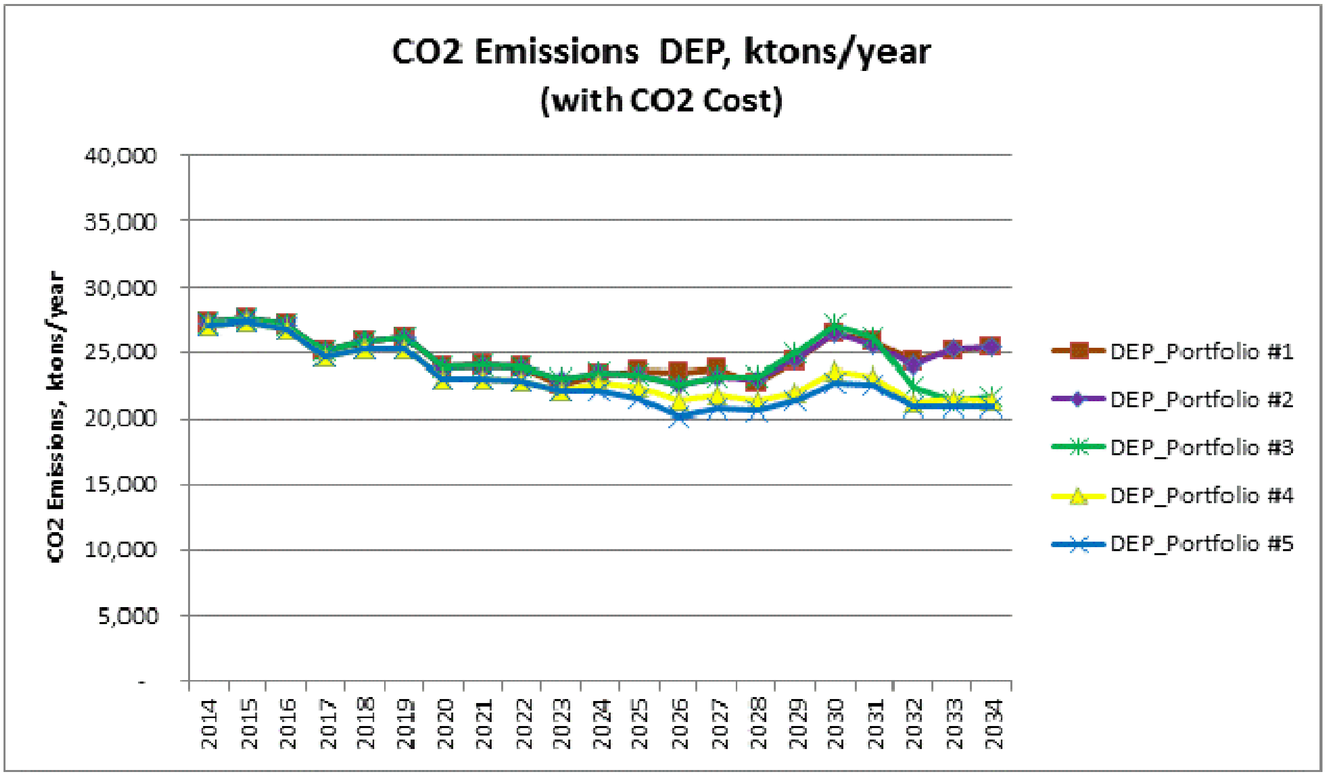
In the With CO_2 Scenario, Portfolio 3 resulted in the lowest PVRR in the Base Case and in the High Fuel and High CO_2 sensitivities. Portfolios 1, 2, and 3 were all very close in overall PVRR. It was also noted that with the retirement of Robinson Nuclear Station in 2030 and without the addition of new nuclear to replace this capacity, Portfolios 1 and 2 result in annual CO_2 emissions that begin to rise by the end of the planning horizon. The cost 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 1 is lower than the PVRR of Portfolio 3 by approximately $1.7 billion dollars. In the High Fuel sensitivity, that difference is reduced to $1.3 billion.

When comparing Portfolios 1 to 2 and Portfolios 4 to 5, the only difference is that Portfolios 2 and 5 incorporate the impact of the addition of Lee Nuclear Station in DEC. From a joint dispatch perspective, this addition also impacts the DEP system because of the energy flow between systems. The addition of Lee Nuclear Station in DEC benefits DEP by an approximate $20 million to $100 million in PVRR over the planning horizon, non-inclusive of the JDA cost sharing arrangement with DEC.

Without the addition of new nuclear to replace retiring nuclear units, 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 Portfolios 1, 2 and 3 through 2034. To this point, when Robinson Nuclear Station is retired in 2030, the CO_2 emissions of Portfolios 1 and 2 are trending to the tons emitted in 2014. Only with the addition of new nuclear generation in Portfolio 3, are CO_2 emissions cost-effectively reduced. Portfolios 4 and 5 resulted in approximately the same CO_2 emissions by 2034 but at a significantly higher cost.

Figure A-1 DEP 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 DEP and DEC unless their licenses can be extended. To date, no nuclear units in the United States have received a license extension beyond 60 years. Portfolio 3 adds Lee Nuclear Station to the DEC system in the 2024-2026 timeframe and one generic nuclear unit each 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 DEP and DEC system 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. Considering the results of the PVRR analysis and the CO_2 emissions restrictions in the Clean Power Plan, Portfolio 3 is considered the Base Case for the 2014 IRP.

Value of Joint Planning

To demonstrate the value of sharing capacity with DEC, 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 both DEP and DEC to a combined Joint Planning Case in which existing and future capacity resources could be shared between DEC and DEP to meet the minimum 14.5% planning reserve margin. In this Joint Planning Case, sharing the Lee Nuclear Station on a load ratio basis with DEC 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 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 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 DEC 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 on the DEC system in the 2025 timeframe and two additional generic nuclear units, one in DEP and one in DEC, 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 PROGRESS OWNED GENERATION

Duke Energy Progress' 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 Progress-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 Progress' nuclear and coal-fired generating units met the vast majority of customer needs by providing 45% and 26%, respectively, of Duke Energy Progress' 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 Progress' plants in service in North Carolina (NC) and South Carolina (SC) with plant statistics, and the system's total generating capability.

Existing Generating Units and Ratings [1, 3]
All Generating Unit Ratings are as of December 31, 2013 unless otherwise noted.

Coal						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Asheville	1	192	191	Arden, NC	Coal	Base
Asheville	2	187	185	Arden, NC	Coal	Base
Mayo [2]	1	746	727	Roxboro, NC	Coal	Base
Roxboro	1	380	379	Semora, NC	Coal	Base
Roxboro	2	667	665	Semora, NC	Coal	Base
Roxboro	3	698	691	Semora, NC	Coal	Base
Roxboro [2]	4	711	698	Semora, NC	Coal	Base
Total Coal		3,581	3,536			

Combustion Turbines						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Asheville	3	185	164	Arden, NC	Natural Gas/Oil	Peaking
Asheville	4	185	160	Arden, NC	Natural Gas/Oil	Peaking
Blewett	1	17	13	Lilesville, NC	Oil	Peaking
Blewett	2	17	13	Lilesville, NC	Oil	Peaking
Blewett	3	17	13	Lilesville, NC	Oil	Peaking
Blewett	4	17	13	Lilesville, NC	Oil	Peaking
Darlington	1	65	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	2	67	48	Hartsville, SC	Oil	Peaking
Darlington	3	67	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	4	66	50	Hartsville, SC	Oil	Peaking
Darlington	5	66	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	6	62	45	Hartsville, SC	Oil	Peaking
Darlington	7	67	51	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	8	66	48	Hartsville, SC	Oil	Peaking
Darlington	9	67	52	Hartsville, SC	Oil	Peaking
Darlington	10	67	51	Hartsville, SC	Oil	Peaking
Darlington	11	67	52	Hartsville, SC	Oil	Peaking
Darlington	12	133	118	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	13	133	116	Hartsville, SC	Natural Gas/Oil	Peaking
Smith [4]	1	183	157	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	2	183	156	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	3	185	155	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	4	186	163	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	6	187	153	Hamlet, NC	Natural Gas/Oil	Peaking
Sutton	1	14	11	Wilmington, NC	Oil/Natural Gas	Peaking
Sutton	2A	31	24	Wilmington, NC	Oil/Natural Gas	Peaking
Sutton	2B	31	26	Wilmington, NC	Oil/Natural Gas	Peaking
Wayne	1/10	192	177	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	2/11	192	174	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	3/12	193	173	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	4/13	191	170	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	5/14	197	169	Goldsboro, NC	Oil/Natural Gas	Peaking
Weatherspoon	1	41	32	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	2	41	32	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	3	41	33	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	4	41	31	Lumberton, NC	Natural Gas/Oil	Peaking
Total NC		2,567	2,212			
Total SC		993	787			
Total CT		3,560	2,999			

Combined Cycle						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Lee	CT1A	223	179	Goldsboro, NC	Natural Gas/Oil	Base
Lee	CT1B	222	179	Goldsboro, NC	Natural Gas/Oil	Base
Lee	CT1C	223	179	Goldsboro, NC	Natural Gas/Oil	Base
Lee	ST1	379	379	Goldsboro, NC	Natural Gas/Oil	Base
Smith [4]	CT7	189	160	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT8	189	157	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	ST4	175	165	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT9	214	178	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT10	214	178	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	ST5	246	250	Hamlet, NC	Natural Gas/Oil	Base
Sutton	CT1A	225	179	Wilmington, NC	Natural Gas/Oil	Base
Sutton	CT1B	225	179	Wilmington, NC	Natural Gas/Oil	Base
Sutton	ST1	267	264	Wilmington, NC	Natural Gas/Oil	Base
Total CC		2,991	2,626			

Hydro						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Blewett	1	4	3	Lilesville, NC	Water	Intermediate
Blewett	2	4	3	Lilesville, NC	Water	Intermediate
Blewett	3	4	4	Lilesville, NC	Water	Intermediate
Blewett	4	5	4	Lilesville, NC	Water	Intermediate
Blewett	5	5	4	Lilesville, NC	Water	Intermediate
Blewett	6	5	4	Lilesville, NC	Water	Intermediate
Marshall	1	2	2	Marshall, NC	Water	Intermediate
Marshall	2	2	2	Marshall, NC	Water	Intermediate
Tillery	1	21	21	Mt. Gilead, NC	Water	Intermediate
Tillery	2	18	18	Mt. Gilead, NC	Water	Intermediate
Tillery	3	21	21	Mt. Gilead, NC	Water	Intermediate
Tillery	4	24	24	Mt. Gilead, NC	Water	Intermediate
Walters	1	36	36	Waterville, NC	Water	Intermediate
Walters	2	40	40	Waterville, NC	Water	Intermediate
Walters	3	36	36	Waterville, NC	Water	Intermediate
Total Hydro		227	222			

Nuclear						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Brunswick [2]	1	975	938	Southport, NC	Uranium	Base
Brunswick[2]	2	953	932	Southport, NC	Uranium	Base
Harris [2]	1	973	928	New Hill, NC	Uranium	Base
Robinson	2	797	741	Hartsville, SC	Uranium	Base
Total NC		2,901	2,798			
Total SC		797	741			
Total Nuclear		3,698	3,539			

Total Generation Capability		
	Winter Capacity (MW)	**Summer Capacity (MW)**
TOTAL DEP SYSTEM - NC	12,267	11,394
TOTAL DEP SYSTEM - SC	1,790	1,528
TOTAL DEP SYSTEM	14,057	12,922

Note 1: Ratings reflect compliance with NERC reliability standards and are gross of co-ownership interest as of 12/31/13.

Note 2: Jointly-owned by NCEMPA: Roxboro 4 - 12.94%; Mayo 1 - 16.17%; Brunswick 1 - 18.33%; Brunswick 2 - 18.33%; and Harris 1 - 16.17%.

Note 3: Resource type based on NERC capacity factor classifications, which may alternate over the forecast period.

Note 4: Richmond County Plant renamed to Sherwood H. Smith Jr. Energy Complex.

Planned Uprates			
Unit	Date	Winter MW	Summer MW
Brunswick 1 [1]	June 2015	10	10
Brunswick 2 [1]	June 2015	10	10
Harris 1 [1]	September 2016	18	14
Lee CC CT1A [1]	May 2018	27.3	27.3
Lee CC CT1B [1]	May 2018	27.3	27.3
Lee CC CT1C [1]	May 2018	27.3	27.3
Sutton CC CT1A [1]	May 2018	27.5	27.5
Sutton CC CT1B [1]	May 2018	27.5	27.5

Note 1: Capacity not reflected in Existing Generating Units and Ratings section.

Retirements				
Unit & Plant Name	**Location**	**Capacity (MW) Winter / Summer**	**Fuel Type**	**Expected Retirement Date**
Cape Fear 5	Moncure, NC	148 / 144	Coal	RETIRED
Cape Fear 6	Moncure, NC	175 / 172	Coal	RETIRED
Cape Fear 1A	Moncure, NC	14 / 11	Combustion Turbine	RETIRED
Cape Fear 1B	Moncure, NC	14 / 12	Combustion Turbine	RETIRED
Cape Fear 2A	Moncure, NC	15 / 12	Combustion Turbine	RETIRED
Cape Fear 2B	Moncure, NC	14 / 11	Combustion Turbine	RETIRED
Cape Fear 1	Moncure, NC	12 / 11	Steam Turbine	RETIRED
Cape Fear 2	Moncure, NC	12 / 7	Steam Turbine	RETIRED
Lee 1	Goldsboro, NC	80 / 74	Coal	RETIRED
Lee 2	Goldsboro, NC	80 / 68	Coal	RETIRED
Lee 3	Goldsboro, NC	252 / 240	Coal	RETIRED
Lee 1	Goldsboro, NC	15 / 12	Combustion Turbine	RETIRED
Lee 2	Goldsboro, NC	27 / 21	Combustion Turbine	RETIRED
Lee 3	Goldsboro, NC	27 / 21	Combustion Turbine	RETIRED
Lee 4	Goldsboro, NC	27 / 21	Combustion Turbine	RETIRED
Morehead 1	Morehead City, NC	15 / 12	Combustion Turbine	RETIRED
Robinson 1	Hartsville, NC	179 / 177	Coal	RETIRED
Robinson 1	Hartsville, NC	15 / 11	Combustion Turbine	RETIRED
Weatherspoon 1	Lumberton, NC	49 / 48	Coal	RETIRED
Weatherspoon 2	Lumberton, NC	49 / 48	Coal	RETIRED
Weatherspoon 3	Lumberton, NC	79 / 74	Coal	RETIRED
Sutton 1	Wilmington, NC	98 / 97	Coal	RETIRED
Sutton 2	Wilmington, NC	95 / 90	Coal	RETIRED
Sutton 3	Wilmington, NC	389 / 366	Coal	RETIRED
Total		1,880 MW / 1,760 MW		

Planning Assumptions - Unit Retirements[a]				
Unit & Plant Name	Location	Capacity (MW)	Fuel Type	Expected Retirement
Asheville 1	Arden, NC	191	Coal	6/2031
Asheville 2	Arden, NC	185	Coal	6/2031
Mayo 1	Roxboro, NC	727	Coal	6/2035
Roxboro 1	Semora, NC	379	Coal	6/2032
Roxboro 2	Semora, NC	665	Coal	6/2032
Roxboro 3	Semora, NC	691	Coal	6/2035
Roxboro 4	Semora, NC	698	Coal	6/2035
Robinson 2 [b]	Hartsville, S.C.	741	Nuclear	6/2030
Darlington 1	Hartsville, S.C.	52	Natural Gas/Oil	6/2020
Darlington 2	Hartsville, S.C.	48	Oil	6/2020
Darlington 3	Hartsville, S.C.	52	Natural Gas/Oil	6/2020
Darlington 4	Hartsville, S.C.	50	Oil	1/2014
Darlington 5	Hartsville, S.C.	52	Natural Gas/Oil	6/2020
Darlington 6	Hartsville, S.C.	45	Oil	1/2014
Darlington 7	Hartsville, S.C.	51	Natural Gas/Oil	6/2020
Darlington 8	Hartsville, S.C.	48	Oil	6/2020
Darlington 9	Hartsville, S.C.	52	Oil	6/2020
Darlington 10	Hartsville, S.C.	51	Oil	6/2020
Darlington 11	Hartsville, S.C.	52	Oil	1/2014
Sutton 1	Wilmington, N.C.	11	Natural Gas/Oil	6/2017
Sutton 2A	Wilmington, N.C.	24	Natural Gas/Oil	6/2017
Sutton 2B	Wilmington, N.C.	26	Natural Gas/Oil	6/2017
Blewett 1	Lilesville, N.C.	13	Oil	6/2027
Blewett 2	Lilesville, N.C.	13	Oil	6/2027
Blewett 3	Lilesville, N.C.	13	Oil	6/2027
Blewett 4	Lilesville, N.C.	13	Oil	6/2027
Weatherspoon 1	Lumberton, N.C.	32	Natural Gas/Oil	6/2027
Weatherspoon 2	Lumberton, N.C.	32	Natural Gas/Oil	6/2027
Weatherspoon 3	Lumberton, N.C.	33	Natural Gas/Oil	6/2027
Weatherspoon 4	Lumberton, N.C.	31	Natural Gas/Oil	6/2027
Total		5071		

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

Operating License Renewal

Planned Operating License Renewal				
Unit & Plant Name	Location	Original Operating License Expiration	Date of Approval	Extended Operating License Expiration
Blewett #1-6 [1]	Lilesville, NC	04/30/08	*Pending*	2058[2]
Tillery #1-4 [1]	Mr. Gilead, NC	04/30/08	*Pending*	2058[2]
Robinson #2	Hartsville, SC	07/31/10	04/19/2004	07/31/2030
Brunswick #2	Southport , NC	12/27/14	06/26/2006	12/27/2034
Brunswick #1	Southport, NC	09/08/16	06/26/2006	09/08/2036
Harris #1	New Hill, NC	10/24/26	12/12/2008	10/24/2046

Note 1: The license renewal application for the Blewett and Tillery Plants was filed with the FERC on 04/26/06; the Company is awaiting issuance of the new license from FERC. Pending receipt of a new license, these plants are currently operating under a renewable one-year license extension, which has been in effect since May 2008.
Although Progress Energy has requested a 50-year license, FERC may not grant this term.

Note 2: Estimated - New license expiration date will be determined by FERC license issuance date and term of granted license.

APPENDIX C: ELECTRIC LOAD FORECAST

Methodology

The Duke Energy Progress 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. Regression analysis 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 1.3%.

Commercial electricity usage changes with the level of regional economic activity, such as personal income or commercial employment, and the impact of weather. 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 0.5% 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 counties that comprise the DEP 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 DEP'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 DEP'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 DEP 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 DEP sales. Fortunately, the worst of the textile decline appears to be over, and DEP's economic vendor expects the Carolina's economy to show solid growth going forward.

Historical information for DEP 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	1,134	1,159	1,184	1,208	1,229	1,241	1,250	1,255	1,260	1,270
Commercial	203	209	213	217	218	217	218	219	219	224
Industrial	4	4	4	4	4	5	5	5	4	4
Total	**1,341**	**1,372**	**1,402**	**1,429**	**1,452**	**1,463**	**1,473**	**1,479**	**1,483**	**1,498**

Table C-3
Electricity Sales (GWh Sold - Years Ended December 31)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Residential	16,003	16,664	16,259	17,200	17,000	17,117	19,108	17,764	16,663	17,387
Commercial	13,019	13,314	13,358	14,033	13,940	13,639	14,184	13,709	13,581	13,517
Industrial	13,036	12,741	12,416	11,883	11,216	10,375	10,677	10,573	10,508	10,634
Military &Other	1,431	1,410	1,419	1,438	1,467	1,497	1,574	1,591	1,602	1,574
Total Retail	43,490	44,129	43,451	44,553	43,622	42,628	45,544	43,637	42,355	43,111
Wholesale	12,439	12,210	12,231	12,656	12,868	12,772	12,772	12,267	12,676	13,336
Total System	**55,928**	**56,340**	**55,682**	**57,209**	**56,489**	**55,400**	**58,316**	**55,903**	**55,031**	**56,447**

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 energy efficiency 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 Progress 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	1.6%	1.5%	1.3%
Includes impact of new EE programs	1.4%	1.3%	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	12,983	12,468	66,007
2016	13,198	12,729	67,004
2017	13,406	12,849	67,903
2018	13,626	13,051	68,850
2019	13,856	13,287	69,819
2020	14,075	13,481	70,749
2021	14,303	13,765	71,578
2022	14,539	13,980	72,471
2023	14,786	14,135	73,349
2024	15,041	14,303	74,237
2025	15,284	14,493	75,080
2026	15,517	14,693	75,933
2027	15,793	14,935	76,937
2028	16,046	15,158	78,079
2029	16,298	15,285	79,152

Note: Table 8-C differs from these values due to a 150 MW firm sale to NCEMC through 2024.

Chart C-1 Load Duration Curve without Energy Efficiency Programs

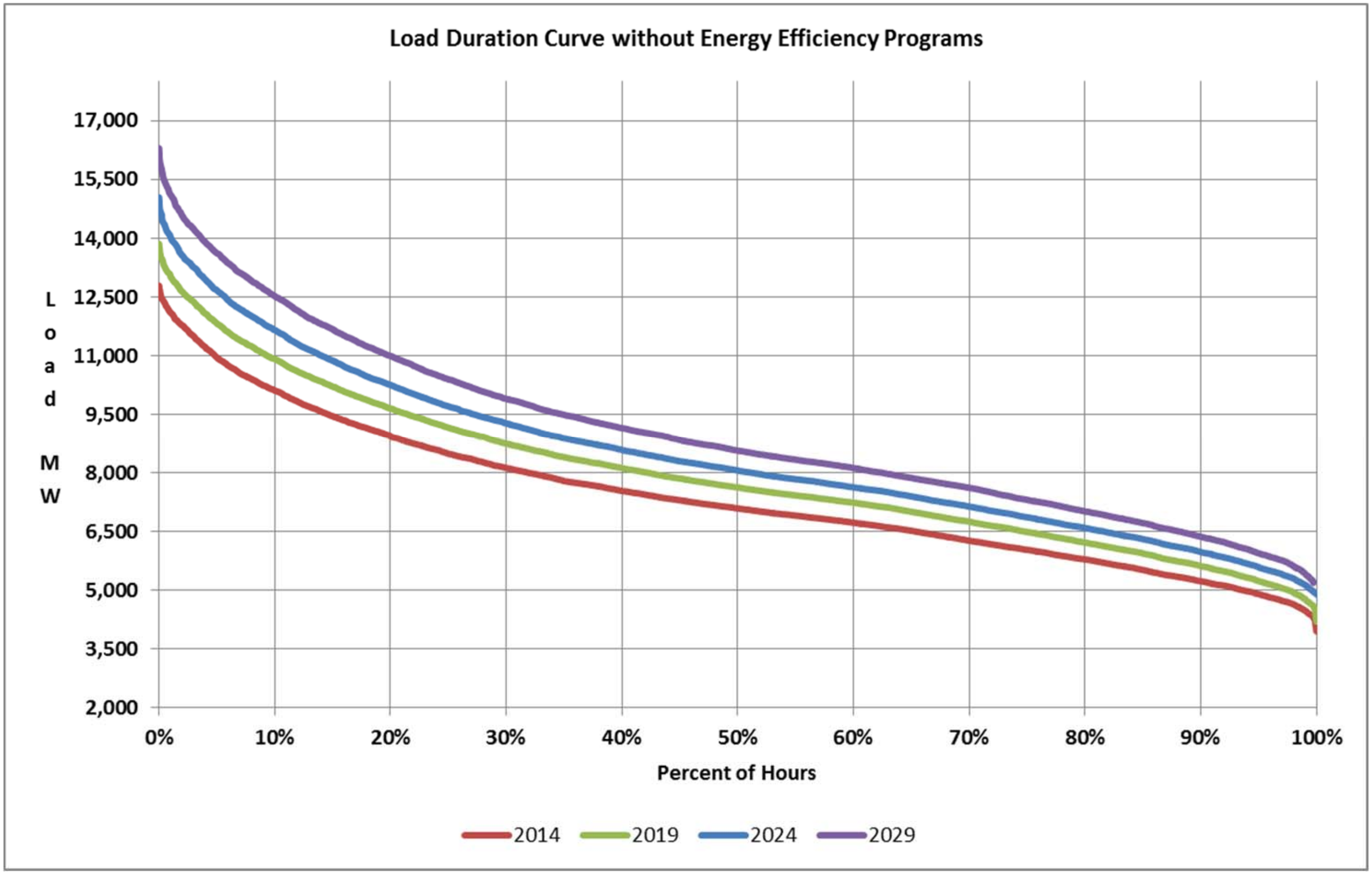
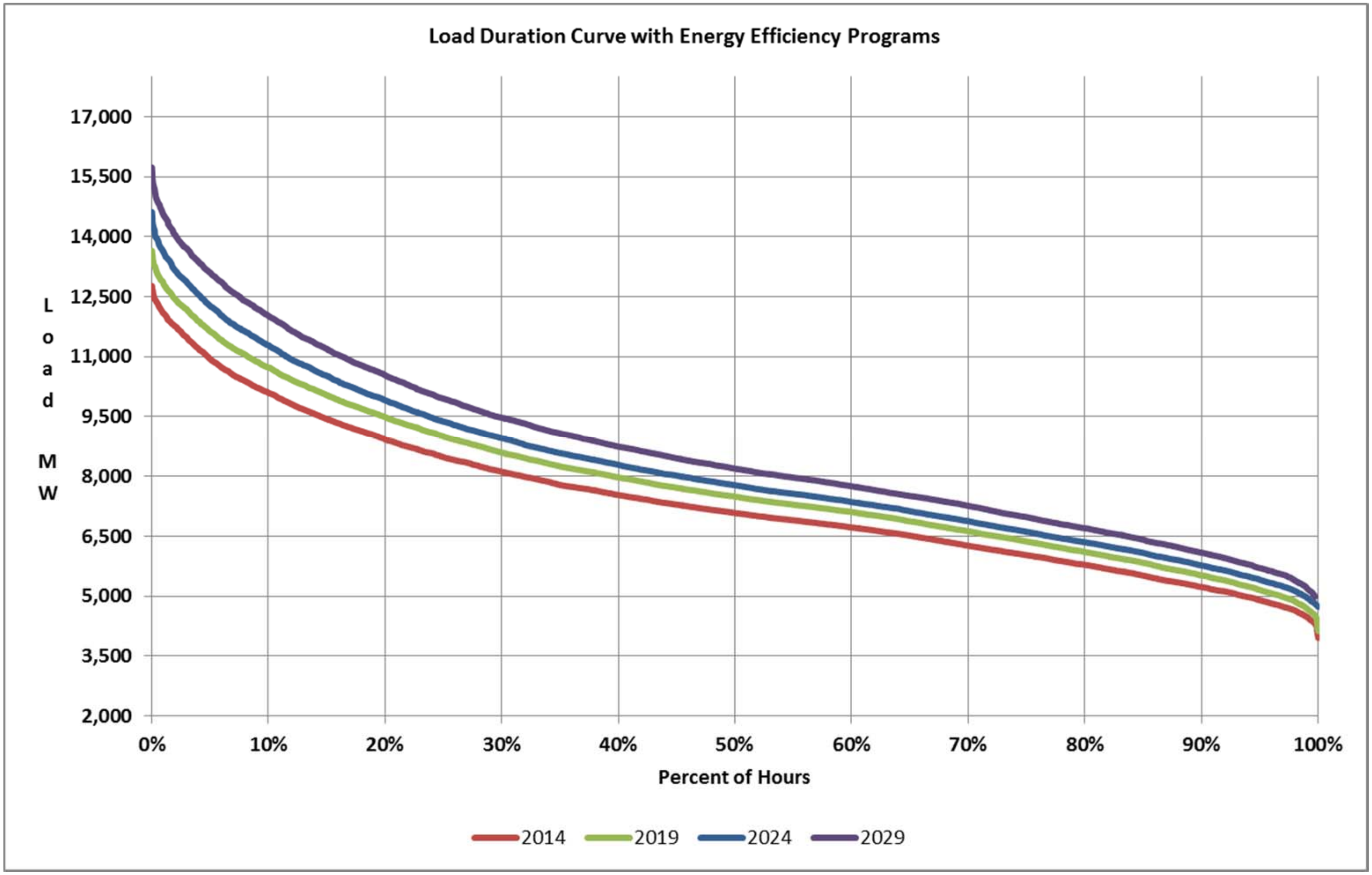


Table C-6
Load Forecast with Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWh)
2015	12,924	12,429	65,660
2016	13,097	12,659	66,408
2017	13,267	12,751	67,083
2018	13,453	12,929	67,825
2019	13,646	13,125	68,561
2020	13,824	13,287	69,236
2021	14,007	13,537	69,797
2022	14,197	13,717	70,419
2023	14,400	13,837	71,034
2024	14,613	13,974	71,667
2025	14,817	14,133	72,285
2026	15,018	14,308	72,949
2027	15,266	14,528	73,785
2028	15,496	14,734	74,783
2029	15,726	14,844	75,738

Note: Table 8-C differs from these values due to a 150 MW firm sale to NCEMC through 2024.

Chart C-2 Load Duration Curve with Energy Efficiency Programs



APPENDIX D: ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT

Demand Side Management and Energy Efficiency Programs

DEP continues to pursue a long-term, balanced capacity and energy strategy to meet the future electricity needs of its customers. This balanced strategy includes a strong commitment to demand side management and EE programs, investments in renewable and emerging energy technologies, and state-of-the art power plants and delivery systems.

DEP 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).

DEP's DSM/EE portfolio currently consists of the following programs, as approved by the North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC).

- Residential Home Energy Improvement
- Residential New Construction
- Residential Neighborhood Energy Saver (Low-Income)
- Residential Appliance Recycling Program
- Residential Energy Efficient Benchmarking Program
- Energy Efficient Lighting Program
- Commercial, Industrial, and Governmental (CIG) Energy Efficiency
- Small Business Energy Saver
- Distribution System Demand Response (DSDR) Program
- Residential EnergyWise Home^{SM}
- CIG Demand Response Automation Program

<u>DSM/EE Program Descriptions</u>

Residential Home Energy Improvement Program
Program Type: Energy Efficiency

The Residential Home Energy Improvement Program offers DEP customers a variety of energy conservation measures designed to increase energy efficiency for existing residential dwellings that can no longer be considered new construction. The prescriptive menu of energy efficiency measures provided by the program allows customers the opportunity to participate based on the needs and characteristics of their individual homes. Financial incentives are provided to participants for each of the conservation measures promoted within this program. The program utilizes a network of pre-qualified contractors to install each of the following energy efficiency measures:

- High-Efficiency Heat Pumps and Central A/C
- Duct Repair
- Level-2 HVAC Tune-up
- Insulation Upgrades/Attic Sealing
- High Efficiency Room Air Conditioners
- Heat Pump Water Heater

Residential Home Energy Improvement Program			
As of:	**Participants**	**Gross MWh Energy Savings**	**Gross Peak kW Demand Savings**
December 31, 2013	93,502	32,145	30,961

Residential New Construction Program
Program Type: Energy Efficiency

The Residential New Construction program serves as a replacement for the Residential Home Advantage program, which ended on March 1, 2013. The Residential New Construction Program offers single family builders and multi-family developers equipment incentives for installing high efficiency HVAC and/or heat pump water heating equipment in new residential construction; or whole house incentives for meeting or exceeding the 2012 North Carolina Energy Conservation Code High Efficiency Residential Option ("HERO").

The primary objectives of this program are to reduce system peak demands and energy consumption within new homes. New construction represents a unique opportunity for capturing cost effective EE savings by encouraging the investment in energy efficiency features that would otherwise be impractical or more costly to install at a later time. These are often referred to as lost opportunities.

Residential New Construction Program			
As of:	**Participants**	**Gross MWh Energy Savings**	**Gross Peak kW Demand Savings**
December 31, 2013	8,046	12,241	4,011

Note: The participants and impacts include both the Residential Home Advantage and New Construction programs.

Residential Neighborhood Energy Saver (Low-Income) Program
Program Type: Energy Efficiency

DEP's Neighborhood Energy Saver Program assists low-income residential customers with energy conservation efforts, which will in turn lessen their household energy costs. The program provides assistance to low-income families by installing a comprehensive package of energy conservation measures that lower energy consumption at no cost to the customer. Prior to installing measures, an energy assessment is conducted on each residence to identify the appropriate measures to install. In addition to the installation of energy efficiency measures, an important component of the Neighborhood Energy Saver program is the provision for one-on-one energy education. Each household receives information on energy efficiency techniques and is encouraged to make behavioral changes to help reduce and control their energy usage. The Neighborhood Energy Saver program is being implemented utilizing a whole neighborhood, door-to-door delivery strategy.

Residential Neighborhood Energy Saver Program			
As of:	**Participants**	**Gross MWh Energy Savings**	**Gross Peak kW Demand Savings**
December 31, 2013	19,228	10,838	1,438

Energy Efficient Lighting Program
Program Type: Energy Efficiency

The Energy Efficient Lighting Program is designed to reduce energy consumption by providing incentives and marketing support through retailers to encourage greater customer adoption of high efficiency lighting products. DEP partners with various manufacturers and retailers across its entire service territory to offer in-store discounts on a wide selection of CFLs, LEDs, and energy-efficient fixtures. The program also targets the purchase of these products through in-store and on-line promotions, while promoting greater awareness through special retail and community events. The program was expanded in 2013 to include new lighting technologies such as LED's, high efficiency incandescent bulbs and energy efficient fixtures.

Energy Efficient Lighting Program			
As of:	**Bulbs Sold**	**Gross MWh Energy Savings**	**Gross Peak kW Demand Savings**
December 31, 2013	9,674,781	786,824	116,146

Residential Appliance Recycling Program
Program Type: Energy Efficiency

The Appliance Recycling Program is designed to reduce energy consumption and provide environmental benefits through the proper removal and recycling of older, less efficient refrigerators and freezers that are operating within residences across the DEP service territory. The program includes scheduling and free appliance pick-up at the customer's location, transportation to a recycling facility, and recovery and recycling of appliance materials. On an annual basis, customers receive free removal and recycling of up to two appliances, as well as an incentive for participation.

Residential Appliance Recycling Program			
As of:	Participants	Gross MWh Energy Savings	Gross Peak kW Demand Savings
December 31, 2013	30,769	32,274	3,547

Residential Energy Efficient Benchmarking Program
Program Type: Energy Efficiency

The Residential Energy Efficient Benchmarking Program is designed to reduce residential electrical consumption by applying behavioral science principals in which a sample of eligible customers receive reports comparing their energy use with neighbors in similar homes. Participants are periodically mailed the individualized reports and can elect to switch to on-line reports at any time during the duration of the program. In addition to the household comparative analysis, the reports provide specific recommendations to motivate participants to reduce their energy consumption. The program also offers an interactive web portal that gives customers greater insight into their energy consumption and actions they can take to become more energy efficient. The web portal includes monthly customer billing data, goal setting and tracking, as well as personalized and community recommended energy efficiency tips.

Residential Energy Efficient Benchmarking Program			
As of:	Participants	Gross MWh Energy Savings	Gross Peak kW Demand Savings
December 31, 2013	43,999	11,945	2,374

Commercial, Industrial, and Governmental (CIG) Energy Efficiency Program
Program Type: Energy Efficiency

The CIG Energy Efficiency Program is available to all CIG customers interested in improving the energy efficiency of their new construction projects or within their existing facilities. New construction incentives provide an opportunity to capture cost effective energy efficiency savings that would otherwise be impractical or more costly to install at a later time. The retrofit market offers a potentially significant opportunity for savings as CIG type customers with older, energy inefficient electrical equipment are often under-funded and need assistance in identifying and retrofitting existing facilities with new high efficiency electrical equipment. The program includes prescriptive incentives for measures that address the following major end-use categories:

- HVAC
- Lighting
- Refrigeration

In addition, the program offers incentives for custom measures to specifically address the individual needs of customers in the new construction or retrofit markets, such as those with more complex applications or in need of energy efficiency opportunities not covered by the prescriptive measures.

The program also seeks to meet the following overall goals:

- Educate and train trade allies, design firms and customers to influence selection of energy efficient products and design practices.
- Educate CIG customers regarding the benefits of energy efficient products and design elements and provide them with tools and resources to cost-effectively implement energy-saving projects.
- Obtain energy and demand impacts that are significant, reliable, sustainable and measureable.
- Influence market transformation by offering incentives for cost effective measures.

CIG Energy Efficiency Program			
As of:	**Participants**	**Gross MWh Energy Savings**	**Gross Peak kW Demand Savings**
December 31, 2013	4,505	244,613	58,879

Small Business Energy Saver Program
Program Type: Energy Efficiency

The Small Business Energy Saver Program is a new direct-install type of program designed to encourage the installation of energy efficiency measures in small, "hard to reach" commercial facilities with an annual demand of 100 kW or less. The program provides a complete energy assessment and installation of measures on a turn-key basis. In addition, the program was designed to minimize financial barriers by incorporating aggressive incentives as well as providing payment options for the remainder of participant costs.

Small Business Energy Saver Program			
As of:	**Participants**	**Gross MWh Energy Savings**	**Gross Peak kW Demand Savings**
December 31, 2013	1,518	5,378	3,810

Distribution System Demand Response Program (DSDR)
Program Type: Energy Efficiency in North Carolina; Demand Response in South Carolina

The DSDR program is an application of Smart Grid technology that provides the capability to reduce peak demand for four to six hours at a time, which is the duration consistent with typical peak load periods, while also maintaining customer delivery voltage above the minimum requirement when the program is in use. The increased peak load reduction capability and flexibility associated with DSDR will result in the displacement of the need for additional peaking generation capacity. This capability is accomplished by investing in a robust system of advanced technology, telecommunications, equipment, and operating controls. The DSDR Program will help DEP implement a least cost mix of demand reduction and generation measures that meet the electricity needs of its customers.

Distribution System Demand Response Program			
As of:	**Participants**	**MWh Energy Savings**	**Summer MW Capability**
December 31, 2013	NA	31,690	195

Residential EnergyWise Home[SM] Program
Program Type: Demand Response

The Residential EnergyWise Home[SM] Program is a direct load control program that allows DEP, through the installation of load control switches at the customer's premise, to remotely control the following residential appliances.

- Central air conditioning or electric heat pumps
- Auxiliary strip heat on central electric heat pumps (Western Region only)
- Electric water heaters (Western Region only)

For each of the control options above, an annual bill credit is provided to program participants in exchange for allowing DEP to control the listed appliances. The program provides DEP 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, heat pump strip heating or water heating unit for a period of time each hour, and (3) the receipt of an annual bill credit from DEP in exchange for allowing DEP to control their electric equipment.

Residential EnergyWise Home Statistics			
As of:	**Participants**	**Summer MW Capability**	**Winter MW Capability**
December 31, 2013	102,837	213	9.1

The following table shows Residential EnergyWise Home[SM] Program activations that were not for testing purposes from July 1, 2012 through June 30, 2014.

Residential EnergyWise Home[SM]			
Start Time	End Time	Duration (Minutes)	MW Load Reduction*
7/6/2012 15:00	7/6/2012 17:00	120	97.1
7/26/2012 15:00	7/26/2012 18:00	180	101.0
3/22/2013 6:45	3/22/2013 7:30	45	6.3
7/18/2013 15:00	7/18/2013 17:00	120	94.3
8/12/2013 15:00	8/12/2013 18:00	180	90.7
1/7/2014 6:30	1/7/2014 9:00	150	9.1
1/8/2014 6:30	1/8/2014 9:00	150	9.1
1/22/2014 6:30	1/22/2014 7:30	60	9.1

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

Commercial, Industrial, and Governmental (CIG) Demand Response Automation Program
Program Type: Demand Response

The CIG Demand Response Automation Program allows DEP to install load control and data acquisition devices to remotely control and monitor a wide variety of electrical equipment capable of serving as a demand response resource. The goal of this program is to utilize customer education, enabling two-way communication technologies, and an event-based incentive structure to maximize load reduction capabilities and resource reliability. The primary objective of this program is to reduce DEP's need for additional peaking generation. This will be accomplished by reducing DEP's seasonal peak load demands, primarily during the summer months, through deployment of load control and data acquisition technologies.

In response to EPA regulations finalized January 2013, a new Emergency Generator Option was implemented effective January 1, 2014, to allow customers with emergency generators to continue participation in demand response programs. To comply with the new rule, dispatch of the Emergency Generator Option must be limited to NERC Level II (EEA2) except for an annual readiness test. The original DRA program design, now referred to as the Curtailable Option, will continue to be dispatched as it has historically.

CIG Demand Response Automation Statistics			
As of:	Premises	Peak Capability (MW)	
		Summer	Winter
December 31, 2013	46	18.1	10.7

The table below shows information for each CIG Demand Response Automation Program non-test control event from July 1, 2012 through June 30, 2014.

CIG Demand Response Automation			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
7/6/2012 13:00	7/6/2012 18:00	300	14.1
7/26/2012 13:00	7/26/2012 19:00	360	15.5
8/16/2012 13:00	8/16/2012 18:00	300	15.4
7/18/2013 13:00	7/18/2013 17:30	270	18.9
8/9/2013 13:00	8/9/2013 19:00	360	17.4
8/12/2013 13:00	8/12/2013 19:00	360	15.6
1/7/2014 8:30	1/7/2014 11:00	150	5.7
1/8/2014 6:00	1/8/2014 10:00	240	7.4
1/22/2014 6:30	1/22/2014 9:30	180	8.0

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

Previously Existing Demand Side Management and Energy Efficiency Programs

Prior to the passage of North Carolina Senate Bill 3 in 2007, DEP had a number of DSM/EE programs in place. These programs are available in both North and South Carolina and include the following:

Energy Efficient Home Program
Program Type: Energy Efficiency

In the early 1980s, DEP introduced an Energy Efficient Home program that provides residential customers with a 5% discount of the energy and demand portions of their electricity bills when their homes met certain thermal efficiency standards that were significantly above the existing building codes and standards. Homes that pass an ENERGY STAR® test receive a certificate as well as a 5% discount on the energy and demand portions of their electricity bills.

Voltage Control
Program Type: Demand Response

This procedure involves reducing distribution voltage, at a level that does not adversely impact customer equipment or operations, during periods of capacity constraints in order to reduce system peak demand.

Curtailable Rates
Program Type: Demand Response

DEP began offering its curtailable rate options in the late 1970s, whereby industrial and commercial customers receive credits for DEP's ability to curtail system load during times of high energy costs and/or capacity constrained periods.

Curtailable Rate Activations			
Date	**Start/End Time**	**Duration (Minutes)**	**MW Load Reduction***
1/7/2014	06:30-11:00	270	211
1/8/2014	06:00-10:00	240	243

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

Time-of-Use Rates
Program Type: Demand Response

DEP has offered voluntary Time-of-Use (TOU) rates to all customers since 1981. These rates provide incentives to customers to shift consumption of electricity to lower-cost off-peak periods and lower their electric bill.

Thermal Energy Storage Rates
Program Type: Demand Response

DEP began offering thermal energy storage rates in 1979. The present General Service (Thermal Energy Storage) rate schedule uses two-period pricing with seasonal demand and energy rates applicable to thermal storage space conditioning equipment. Summer on-peak hours are noon to 8 p.m. and non-summer hours of 6 a.m. to 1 p.m. weekdays.

Real-Time Pricing
Program Type: Demand Response

DEP's Large General Service (Experimental) Real Time Pricing tariff was implemented in 1998. This tariff uses a two-part real time pricing rate design with baseline load representative of historic usage. Hourly rates are provided on the prior business day. A minimum of 1 MW load is required. This rate schedule is presently fully subscribed.

Summary of Available Existing Demand-Side and Energy Efficiency Programs

The following table provides current information available at the time of this report on DEP's pre-Senate Bill 3 DSM/EE programs (i.e., those programs that were in effect prior to January 1, 2008). This information, where applicable, includes program type, capacity, energy, and number of customers enrolled in the program as of the end of 2013, as well as load control activations since those enumerated in DEP's last biennial resource plan. The energy savings impacts of these existing programs are embedded within DEP's load and energy forecasts.

Program Description	Type	Capacity (MW)	Annual Energy (MWH)	Participants	Activations Since Last Biennial Report
Energy Efficiency Programs[3]	EE	477	NA	NA	NA
Real Time Pricing (RTP)	DSM	55	NA	105	NA
Commercial & Industrial TOU	DSM	6	NA	29,836	NA
Residential TOU	DSM	11	NA	28,409	NA
Curtailable Rates	DSM	285	NA	86	2
Voltage Control	DSM	75	NA	NA	88

Since DEP's last biennial resource plan was filed on September 4, 2012, there have been 88 voltage control activations through July 16, 2013. The following table shows the date, starting and ending time, and duration for all voltage control activations since September 2012.

Voltage Control		
Start Time	**End Time**	**Duration (Minutes)**
9/4/2012 11:03	9/4/2012 11:52	49
9/7/2012 13:31	9/7/2012 14:30	59
9/13/2012 21:52	9/13/2012 22:43	51
9/16/2012 15:09	9/16/2012 16:03	54
9/17/2012 21:51	9/17/2012 22:34	43
10/8/2012 14:00	10/8/2012 15:00	60
10/19/2012 10:02	10/19/2012 10:49	47
10/26/2012 10:32	10/26/2012 11:35	63
10/31/2012 15:00	10/31/2012 15:17	17
11/1/2012 14:06	11/1/2012 14:21	15
11/2/2012 7:00	11/2/2012 7:34	34

[3] Impacts from these existing programs are embedded within the load and energy forecast.

Voltage Control		
Start Time	**End Time**	**Duration (Minutes)**
11/2/2012 15:01	11/2/2012 15:20	19
11/8/2012 16:41	11/8/2012 16:55	14
11/9/2012 10:15	11/9/2012 10:46	31
12/23/2012 7:45	12/23/2012 8:08	23
12/31/2012 7:34	12/31/2012 11:00	206
12/31/2012 16:25	12/31/2012 16:56	31
1/3/2013 14:28	1/3/2013 14:58	30
1/4/2013 9:37	1/4/2013 9:59	22
1/21/2013 13:23	1/21/2013 13:45	22
1/23/2013 10:18	1/23/2013 10:34	16
1/23/2013 15:34	1/23/2013 16:27	53
1/24/2013 14:03	1/24/2013 15:12	69
2/12/2013 15:01	2/12/2013 15:08	7
3/7/2013 13:15	3/7/2013 13:45	30
3/20/2013 8:34	3/20/2013 9:02	28
3/21/2013 7:02	3/21/2013 7:30	28
3/22/2013 6:45	3/22/2013 7:30	45
6/12/2013 10:59	6/12/2013 11:31	32
6/26/2013 11:09	6/26/2013 11:39	30
7/11/2013 15:00	7/11/2013 18:00	180
7/17/2013 15:01	7/17/2013 18:04	183
7/18/2013 14:01	7/18/2013 17:00	179
7/23/2013 14:03	7/23/2013 17:02	179
7/25/2013 11:00	7/25/2013 11:15	15
7/31/2013 15:02	7/31/2013 16:57	115
8/1/2013 15:00	8/1/2013 18:00	180
8/8/2013 15:00	8/8/2013 18:00	180
8/9/2013 15:00	8/9/2013 18:01	182
8/12/2013 14:00	8/12/2013 18:00	240
8/13/2013 15:00	8/13/2013 17:40	160
8/22/2013 15:00	8/22/2013 18:00	180
8/23/2013 15:00	8/23/2013 15:59	60
8/27/2013 15:03	8/27/2013 18:00	177
8/28/2013 16:00	8/28/2013 16:56	56
8/29/2013 15:59	8/29/2013 17:00	61
9/3/2013 15:00	9/3/2013 16:00	60
9/8/2013 15:29	9/8/2013 15:39	11
9/9/2013 16:00	9/9/2013 17:00	60

Voltage Control		
Start Time	**End Time**	**Duration (Minutes)**
9/25/2013 09:43	9/25/2013 09:57	14
9/25/2013 15:00	9/25/2013 15:27	27
10/30/2013 10:21	10/30/2013 10:37	15
11/6/2013 14:28	11/6/2013 14:49	20
11/13/2013 06:30	11/13/2013 07:02	32
11/14/2013 06:15	11/14/2013 08:00	105
12/10/2013 20:03	12/10/2013 20:12	9
1/7/2014 07:07	1/7/2014 07:54	46
1/7/2014 07:54	1/7/2014 09:21	87
1/8/2014 07:00	1/8/2014 08:00	60
1/9/2014 22:35	1/9/2014 22:45	10
1/13/2014 06:30	1/13/2014 08:30	120
1/18/2014 10:12	1/18/2014 10:20	8
1/22/2014 13:08	1/22/2014 13:40	32
1/22/2014 13:40	1/22/2014 13:58	18
1/24/2014 06:30	1/24/2014 08:30	120
1/28/2014 10:00	1/28/2014 10:40	40
1/29/2014 07:30	1/29/2014 09:32	122
1/30/2014 07:00	1/30/2014 09:04	124
2/7/2014 06:30	2/7/2014 08:30	121
2/14/2014 18:53	2/14/2014 19:21	27
2/27/2014 06:30	2/27/2014 08:30	120
3/4/2014 07:01	3/4/2014 07:59	58
3/14/2014 06:45	3/14/2014 08:06	81
3/26/2014 06:30	3/26/2014 08:00	90
3/27/2014 06:00	3/27/2014 08:00	120
5/1/2014 08:00	5/1/2014 10:02	122
5/7/2014 08:00	5/7/2014 10:01	121
5/13/2014 13:00	5/13/2014 15:00	120
5/22/2014 13:00	5/22/2014 15:00	120
6/5/2014 13:00	6/5/2014 15:00	120
6/10/2014 15:00	6/10/2014 18:00	180
6/17/2014 15:00	6/17/2014 18:00	180
6/19/2014 15:00	6/19/2014 17:06	126
6/26/2014 15:00	6/26/2014 16:08	68
7/2/2014 15:00	7/2/2014 18:00	180
7/9/2014 15:00	7/9/2014 16:03	63
7/14/2014 15:00	7/14/2014 18:00	180

Voltage Control		
Start Time	End Time	Duration (Minutes)
7/16/2014 10:00	7/16/2014 11:00	60

Summary of Prospective Program Opportunities

DEP is continually seeking to enhance its DSM/EE portfolio by: (1) adding new or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new measurement and verification (M&V) results, and (3) other EE pilots. The following projects represent program enhancements that are being considered for possible implementation within the biennium for which this IRP is filed.

- Small Business Demand Response – Investigating the potential for a new demand response program targeted toward the small business market segment.
- Neighborhood Energy Saver Program -- DEP is reviewing various options for expanding its existing low-income energy efficiency program including but not limited to consideration for additional measures, broader reaching efforts, and additional delivery/implementation channels.
- Multi-Family – Investigating a potential expansion of DEC's Multi-Family Program to the DEP service area.
- K-12 Education – Investigating a potential expansion of DEC's K-12 Education Program to the DEP service area.
- Residential Energy Benchmarking – Investigating a potential expansion of DEC's My Home Energy Report (MyHER) Program as a replacement for DEP's Residential Energy Efficient Benchmarking (REEB) Program.

EE and DSM Program Screening

The Company evaluates the costs and benefits of DSM and EE programs and measures by using the same data for both generation planning and DSM/EE program planning to ensure that demand-side 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 (PCT).

- 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, however, the tables provided in the DEP IRP have been changed to the same format as those included in the DEC IRP to improve the ability to compare the two documents.

In early 2012, DEP commissioned a new energy efficiency market potential study to obtain new estimates of the technical, economic and achievable potential for EE savings within the DEP service area. The final report, "Progress Energy Carolinas: Electric Energy Efficiency Potential Assessment," was prepared by Forefront Economics Inc. and H. Gil Peach and Associates, LLC and was completed on June 5, 2012. Achievable potential was derived using energy efficiency measure bundles and conceptual program designs to estimate participation, savings and program spending over a 20 year forecast period under a specific set of assumptions, which includes the significant effect of certain large commercial and industrial customers "opting-out" of the programs.

The study results are suitable for integrated resource planning 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. It did not, however, attempt to closely forecast EE achievements in the short-term or from year to year. Such an annual accounting is highly sensitive to the nature of programs adopted, the timing of the introduction of those programs, and other factors. As a result, it was not designed to provide detailed specifications and work plans required for program implementation. This study provides part of the picture for planning EE programs. Fully implementable EE program plans are best developed considering this study along with the experience gained from currently running programs, input from DEP program managers and EE planners, and with the possible assistance of implementation contractors.

The tables below provide the base case projected load impacts of all DEP EE and DSM programs implemented since 2007 on a Gross and Net of Free Riders basis (responsive to Recommendation Number 10 above) and also includes impacts from programs implemented prior to SB-3. 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, these tables include a column that shows historical EE program savings since the inception of the EE programs through the end of 2013, which accounts for approximately an additional 1,143 GWh of Gross energy savings (815 Net GWh) and 222 MW of Gross annual peak demand savings (165 Net MW)[4].

[4] Includes savings from DEP's 2007 CFL Pilot and 2009-11 Solar Water Heating Pilot Program.

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

	Annual MWh Load Reduction					Annual Peak MW Reduction				
	Including measures added in 2014 and beyond				Including measures added since 2007					
Year	Post SB-3 EE	DSM	DSDR	Total		EE	DSM	DSDR	Pre SB-3 Programs	Total Annual
2007-13					1,142,871					
2014	225,214	3,174	55,969	284,357	1,427,227	21	255	311	283	870
2015	467,656	3,506	56,805	527,967	1,670,838	60	288	313	284	945
2016	724,195	3,806	57,580	785,581	1,928,452	101	323	314	287	1,025
2017	915,163	4,083	58,727	977,973	2,120,844	139	355	321	290	1,105
2018	1,135,353	4,336	59,844	1,199,533	2,342,403	173	382	328	293	1,176
2019	1,381,341	4,589	61,024	1,446,954	2,589,825	210	407	334	296	1,247
2020	1,644,724	4,811	62,221	1,711,756	2,854,627	252	409	340	297	1,298
2021	1,918,355	4,811	63,414	1,986,580	3,129,451	297	409	347	297	1,350
2022	2,185,183	4,811	64,614	2,254,608	3,397,479	342	409	353	297	1,401
2023	2,444,434	4,811	65,750	2,514,995	3,657,866	386	409	359	297	1,451
2024	2,695,143	4,811	66,930	2,766,884	3,909,755	428	410	366	297	1,501
2025	2,894,882	4,811	68,090	2,967,783	4,110,654	467	410	372	297	1,546
2026	3,074,232	4,811	69,222	3,148,265	4,291,136	499	410	378	297	1,584
2027	3,230,876	4,811	70,356	3,306,043	4,448,914	527	410	384	297	1,618
2028	3,362,169	4,811	71,509	3,438,489	4,581,360	549	410	391	297	1,647
2029	3,467,037	4,811	72,662	3,544,510	4,687,381	571	410	397	297	1,675

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

	Annual MWh Load Reduction					Annual Peak MW Reduction				
	Including measures added in 2014 and beyond				Including measures added since 2007					
Year	Post SB-3 EE	DSM	DSDR	Total		EE	DSM	DSDR	Pre SB-3 Programs	Total Annual
2007-13					814,514					
2014	168,207	3,174	55,969	227,350	1,041,863	16	255	311	283	865
2015	349,155	3,506	56,805	409,466	1,223,980	45	288	313	284	930
2016	540,671	3,806	57,580	602,057	1,416,571	75	323	314	287	999
2017	693,710	4,083	58,727	756,520	1,571,034	105	355	321	290	1,071
2018	867,899	4,336	59,844	932,079	1,746,593	132	382	328	293	1,135
2019	1,061,862	4,589	61,024	1,127,475	1,941,989	161	407	334	296	1,198
2020	1,268,621	4,811	62,221	1,335,653	2,150,167	194	409	340	297	1,240
2021	1,482,250	4,811	63,414	1,550,475	2,364,989	229	409	347	297	1,282
2022	1,689,034	4,811	64,614	1,758,459	2,572,972	264	409	353	297	1,323
2023	1,888,860	4,811	65,750	1,959,421	2,773,935	298	409	359	297	1,363
2024	2,080,948	4,811	66,930	2,152,689	2,967,202	330	410	366	297	1,403
2025	2,233,893	4,811	68,090	2,306,794	3,121,307	360	410	372	297	1,439
2026	2,370,957	4,811	69,222	2,444,990	3,259,504	385	410	378	297	1,470
2027	2,490,922	4,811	70,356	2,566,089	3,380,602	406	410	384	297	1,497
2028	2,591,975	4,811	71,509	2,668,295	3,482,809	423	410	391	297	1,521
2029	2,673,528	4,811	72,662	2,751,001	3,565,515	440	410	397	297	1,544

Pursuing EE and DSM initiatives is not expected to meet the growing demand for electricity. DEP still envisions the need to secure additional generation, as well as cost-effective renewable generation, but the EE and DSM programs offered by DEP 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

High EE Savings Projection

DEP 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 2014-2018.

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 DEP in the past and much higher than the forecasted savings contained in the market potential study. The effort to meet them will require a substantial expansion of DEP'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 a 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				
	Including measures added in 2014 and beyond				Including measures added since 2007					
Year	Post SB-3 EE	DSM	DSDR	Total		EE	DSM	DSDR	Pre SB-3 Programs	Total Annual
2007-13					1,142,871					
2014	270,000	3,174	55,969	329,143	1,472,014	25	255	311	283	874
2015	730,691	3,506	56,805	791,002	1,933,873	86	288	313	284	971
2016	1,193,547	3,806	57,580	1,254,933	2,397,804	163	323	314	287	1,087
2017	1,659,265	4,083	58,727	1,722,075	2,864,945	241	355	321	290	1,207
2018	2,127,837	4,336	59,844	2,192,017	3,334,887	319	382	328	293	1,322
2019	2,599,487	4,589	61,024	2,665,100	3,807,970	395	407	334	296	1,432
2020	3,074,507	4,811	62,221	3,141,539	4,284,410	472	409	340	297	1,518
2021	3,552,279	4,811	63,414	3,620,504	4,763,375	552	409	347	297	1,605
2022	4,032,073	4,811	64,614	4,101,498	5,244,369	632	409	353	297	1,691
2023	4,514,109	4,811	65,750	4,584,670	5,727,541	712	409	359	297	1,777
2024	4,998,339	4,811	66,930	5,070,080	6,212,950	791	410	366	297	1,864
2025	5,484,750	4,811	68,090	5,557,651	6,700,522	875	410	372	297	1,954
2026	5,973,132	4,811	69,222	6,047,165	7,190,036	957	410	378	297	2,042
2027	6,463,374	4,811	70,356	6,538,541	7,681,412	1,039	410	384	297	2,130
2028	6,957,091	4,811	71,509	7,033,411	8,176,282	1,118	410	391	297	2,216
2029	7,454,639	4,811	72,662	7,532,112	8,674,983	1,205	410	397	297	2,309

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

	Annual MWh Load Reduction					Annual Peak MW Reduction				
	Including measures added in 2014 and beyond				Including measures added since 2007					
Year	Post SB-3 EE	DSM	DSDR	Total		EE	DSM	DSDR	Pre SB-3 Programs	Total Annual Peak
2007-13					814,514					
2014	201,657	3,174	55,969	260,800	1,075,313	19	255	311	283	868
2015	545,539	3,506	56,805	605,850	1,420,363	64	288	313	284	949
2016	891,081	3,806	57,580	952,467	1,766,980	122	323	314	287	1,046
2017	1,257,753	4,083	58,727	1,320,563	2,135,077	183	355	321	290	1,149
2018	1,626,585	4,336	59,844	1,690,765	2,505,278	244	382	328	293	1,247
2019	1,998,273	4,589	61,024	2,063,886	2,878,400	304	407	334	296	1,341
2020	2,371,452	4,811	62,221	2,438,484	3,252,997	364	409	340	297	1,410
2021	2,744,730	4,811	63,414	2,812,955	3,627,469	427	409	347	297	1,480
2022	3,116,583	4,811	64,614	3,186,008	4,000,522	489	409	353	297	1,548
2023	3,488,137	4,811	65,750	3,558,698	4,373,212	550	409	359	297	1,615
2024	3,859,268	4,811	66,930	3,931,009	4,745,523	611	410	366	297	1,684
2025	4,232,415	4,811	68,090	4,305,316	5,119,830	675	410	372	297	1,754
2026	4,606,691	4,811	69,222	4,680,724	5,495,238	738	410	378	297	1,823
2027	4,983,093	4,811	70,356	5,058,260	5,872,774	801	410	384	297	1,892
2028	5,363,385	4,811	71,509	5,439,705	6,254,219	862	410	391	297	1,960
2029	5,748,479	4,811	72,662	5,825,952	6,640,466	929	410	397	297	2,033

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 integrated resource plan. However, the high EE savings forecast was evaluated in two portfolios included in this IRP. DEP 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.

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 Progress' Distribution System Demand Response (DSDR) program is an Integrated Volt-Var Control (IVVC) program that will better manage the application and operation of voltage regulators (the Volt) and capacitors (the VAR) on the Duke Energy Progress 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 projected capability of DSDR is 236 incremental MW of voltage reduction, based upon the 2007 distribution system summer peak. The incremental 236 MW of peak demand reduction will be validated through system level analysis performed by the Distribution Management System ("DMS") during the 2014 summer peak season, with the results provided as part of the 2015 DSDR Evaluation, Measurement and Verification ("EM&V") report filing in June 2015. The incremental voltage reduction from the DSDR project does not include the previously available 75 MW of voltage reduction capabilities, which is added to the DSDR capabilities for the gross total.

Further detail regarding the total projected smart grid impacts associated with the DSDR program is provided in the following table, which presents a breakout of total DSDR peak demand and annual energy savings by source.

Program Savings by Source (at generator)

Year	Peak MW Demand Savings			MWh Energy Savings		
	Voltage Reduction	Reduced Line Losses	All Sources	Voltage Reduction	Reduced Line Losses	All Sources
2014	305	6	311	24,400	31,569	55,969
2015	307	6	313	24,523	32,281	56,805
2016	308	6	314	24,646	32,934	57,580
2017	315	6	321	25,160	33,566	58,727
2018	321	7	328	25,643	34,201	59,844
2019	327	7	334	26,154	34,870	61,024
2020	333	7	340	26,668	35,553	62,221
2021	340	7	347	27,184	36,231	63,414
2022	346	7	353	27,703	36,911	64,614
2023	352	7	359	28,159	37,591	65,750
2024	358	7	365	28,666	38,265	66,930
2025	365	7	372	29,164	38,926	68,090
2026	371	8	379	29,641	39,581	69,222
2027	377	8	385	30,125	40,231	70,356
2028	383	8	391	30,625	40,884	71,509

Discontinued Demand Side Management and Energy Efficiency Programs

Since the last biennial Resource Plan filing, DEP discontinued the following DSM/EE programs or measures.

- The Residential Home Advantage program – DEP received NCUC approval to close the program to new applications effective March 1, 2012 and cancel the program effective March 1, 2013 since it was determined that the program was no longer cost effective due to improved building energy codes as well as more stringent Energy Star® program requirements.

Rejected Demand Side Management and Energy Efficiency Programs

Since the last biennial Resource Plan filing, DEP has not rejected any cost-effective DSM/EE programs or measures.

Current and Anticipated Consumer Education Programs

In addition to the DSM/EE programs previously listed, DEP also has the following informational and educational programs.

- On Line Account Access
- "Lower My Bill" Toolkit
- Online Energy Saving Tips

- Energy Resource Center
- Large Account Management
- eSMART Kids Website
- Community Events

On Line Account Access

On Line Account Access provides energy analysis tools to assist customers in gaining a better understanding of their energy usage patterns and identifying opportunities to reduce energy consumption. The service allows customers to view their past 24 months of electric usage including the date the bill was mailed; number of days in the billing cycle; and daily temperature information. This program was initiated in 1999.

"Lower My Bill" Toolkit

This tool, implemented in 2004, provides on-line tips and specific steps to help customers reduce energy consumption and lower their utility bills. These range from relatively simple no-cost steps to more extensive actions involving insulation and heating and cooling equipment.

Online Energy Saving Tips

DEP has been providing tips on how to reduce home energy costs since approximately 1981. DEP's web site includes information on household energy wasters and how a few simple actions can increase efficiency. Topics include: Energy Efficient Heat Pumps, Mold, Insulation R-Values, Air Conditioning, Appliances and Pools, Attics and Roofing, Building/Additions, Ceiling Fans, Ducts, Fireplaces, Heating, Hot Water, Humidistats, Landscaping, Seasonal Tips, Solar Film, and Thermostats.

Energy Resource Center

In 2000, DEP began offering its large commercial, industrial, and governmental customers a wide array of tools and resources to use in managing their energy usage and reducing their electrical demand and overall energy costs. Through its Energy Resource Center, located on the DEP web site, DEP provides newsletters, online tools and information, which cover a variety of energy efficiency topics such as electric chiller operation, lighting system efficiency, compressed air systems, motor management, variable speed drives and conduct an energy audit.

Large Account Management

All DEP commercial, industrial, and governmental customers with an annual electric bill greater than $250,000 are assigned to a DEP Account Executive (AE). The AEs are available to personally assist customers in evaluating energy improvement opportunities and can bring in other internal resources to provide detailed analyses of energy system upgrades. The AEs provide their customers with a monthly electronic newsletter, which includes energy efficiency topics and tips. They also offer numerous educational opportunities in group settings to provide information about DEP's new DSM and EE program offerings and to help ensure the customers are aware of the latest energy improvement and system operational techniques.

e-SMART Kids Website

DEP is offering an educational online resource for teachers and students in our service area called e-SMART Kids. The web site educates students on energy efficiency, conservation, and renewable energy and offers interactive activities in the classroom. It is available on the web at http://progressenergy.e-smartonline.net/index.php.

Community Events

DEP representatives participated in community events across the service territory to educate customers about DEP's energy efficiency programs and rebates and to share practical energy saving tips. DEP energy experts attended events and forums to host informational tables and displays, and distributed handout materials directly encouraging customers to learn more about and sign up for approved DSM/EE energy saving programs.

Discontinued Consumer Education Programs

DEP discontinued the following educational programs since the last biennial Resource Plan filing.

- Customized Home Energy Report – A free tool that was used to educate residential customers about their household energy usage and how to save money by saving energy.

APPENDIX E: FUEL SUPPLY

Duke Energy Progress' 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 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 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 DEP'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, DEP 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, DEP 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 Progress 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.

Technical Screening

The first step in the Company's supply-side screening process for the IRP is a technical screening of the technologies to eliminate those that have technical limitations, commercial availability issues, or are not feasible in the Duke Energy Progress 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.

<u>Economic Screening</u>

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 Progress has included supercritical pulverized coal (SCPC) with carbon capture sequestration (CCS) and integrated gasification combined cycle (IGCC) technologies with CCS of 1,100 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 CO_2 costs included.

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

The renewable screening curves show solar is a more 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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APPENDIX G: ENVIRONMENTAL COMPLIANCE

Legislative and Regulatory Issues

Duke Energy Progress, 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 Progress is actively monitoring or engaged in that could potentially influence the Company's existing generation portfolio and choices for new generation resources.

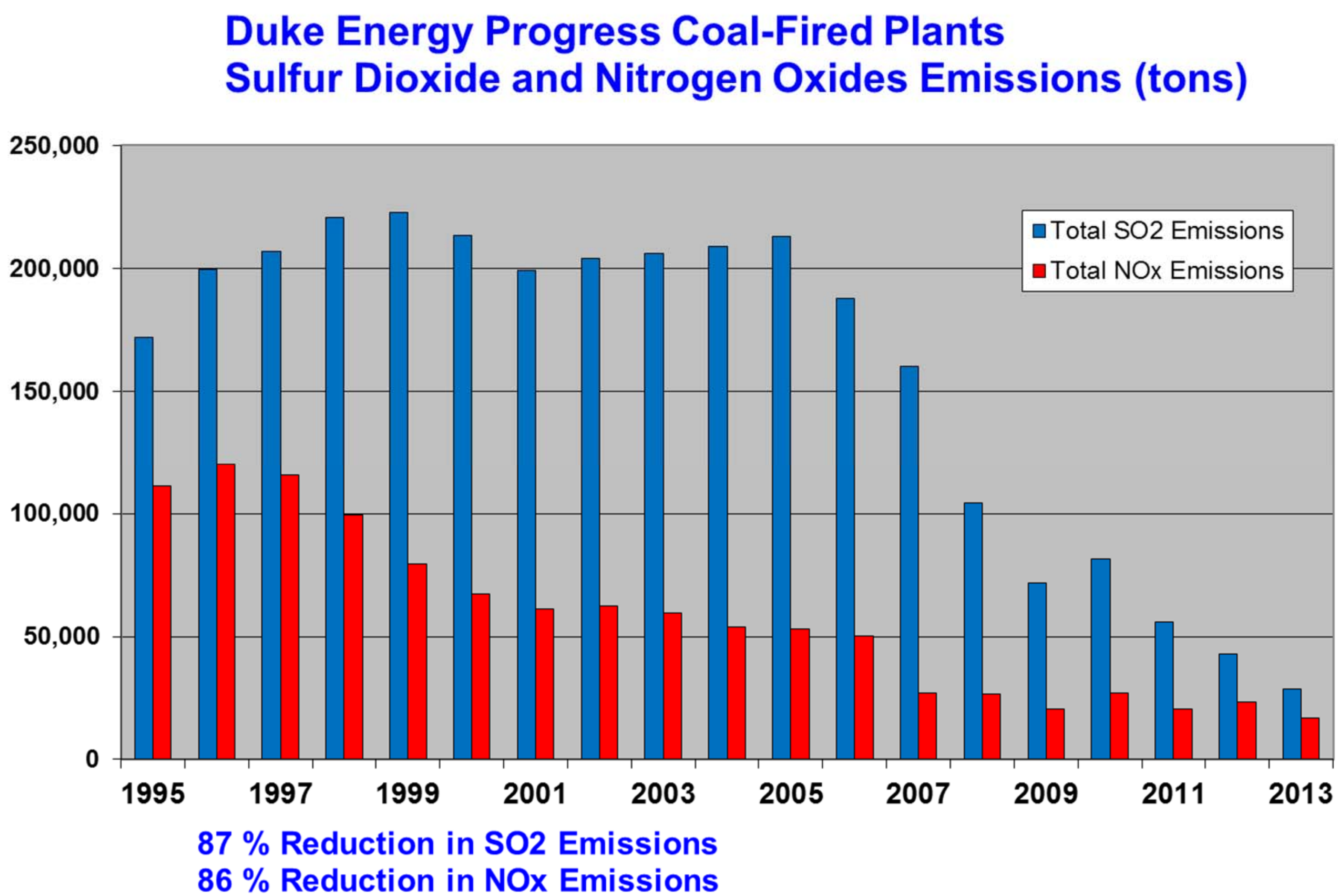
Air Quality

Duke Energy Progress 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 requirements, Duke Energy Progress reduced SO_2 emissions by approximately 93% from 2000 to 2013. Also in 2013, as a result of complying with both the NC CSA and NO_X SIP Call requirements, Duke Energy Progress reduced NO_X emissions by approximately 88% from 2000 levels. The landmark CSA 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 Progress' input and support. Further reductions are expected in 2014 through the retirements Sutton coal units and their replacement with a state-of-the-art gas-fired combined cycle unit.

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 DEP facilities.

Chart G-1 DEP 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 Progress 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), however, on December 30, 2011 the CSAPR was stayed by the D.C. Circuit. 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 Progress 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 Progress 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. 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.

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 Progress cannot predict the outcome of the litigation or how it might affect the MATS requirements as they apply to operations, Duke Energy Progress 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. No areas served by Duke Energy Progress were classified as non-attainment.

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 Progress 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 Progress 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 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 Progress facilities. The reduction in SO_2 and NO_X emissions to address the $PM_{2.5}$ standards has been achieved through the CAIR and the NC CSA. It is unclear if the new lower annual $PM_{2.5}$ standard will require additional SO_2 or NO_X emission reduction requirements at any Duke Energy Progress 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 Progress 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 Progress 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. The proposed emission limits for PC and IGCC units would require carbon capture and sequestration (CCS) technology to meet. For numerous reasons, Duke Energy Progress 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. Duke Energy Progress 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 Progress cannot predict the outcome of EPA's rulemaking, or the approach that North Carolina might take in developing its regulations. Therefore, Duke Energy Progress 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 was signed on May 19, 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 entrainment (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 are affected sources, with the exception of Smith Energy[5].

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
- 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

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

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 is expected to be published in the Federal Register in the August to September 2014 timeframe with a 60-day effective date. The rule requires facilities with a NPDES permit that expire 45-months after the effective date of the rule to submit all necessary 316(b) reports with the renewal application. For facilities with a NPDES permit that expire prior to the 45-month date 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 and 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 to 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 of the rule. 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**

[redacted]

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

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted] [redacted]

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	RALEIGH	NC	Diesel Fuel	5,000.00	Intermediate/Peaking	Yes
Facility 2	CHOCOWINITY	NC	Diesel Fuel	1,800.00	Intermediate/Peaking	Yes
Facility 3	CARY	NC	Diesel Fuel	5,000.00	Intermediate/Peaking	Yes
Facility 4	KURE BEACH	NC	Diesel Fuel	300.00	Intermediate/Peaking	Yes
Facility 5	KURE BEACH	NC	Diesel Fuel	300.00	Intermediate/Peaking	Yes
Facility 6	RALEIGH	NC	Diesel Fuel	2,472.00	Intermediate/Peaking	Yes
Facility 7	RALEIGH	NC	Diesel Fuel	6,000.00	Intermediate/Peaking	Yes
Facility 8	RALEIGH	NC	Diesel Fuel	6,500.00	Intermediate/Peaking	Yes
Facility 9	Morrisville	NC	Diesel Fuel	750.00	Peaking	Yes
Facility 10	Clayton	NC	Diesel Fuel	3,000.00	Peaking	Yes
Facility 11	Asheville	NC	Diesel Fuel	750.00	Peaking	Yes
Facility 12	Asheville	NC	Diesel Fuel	350.00	Peaking	Yes
Facility 13	Oxford	NC	Diesel Fuel	600.00	Peaking	Yes
Facility 14	Wilmington	NC	Diesel Fuel	350.00	Peaking	Yes
Facility 15	Rocky Point	NC	Diesel Fuel	350.00	Peaking	Yes
Facility 16	Whispering Pines	NC	Diesel Fuel	350.00	Peaking	Yes
Facility 17	Hope Mills	NC	Diesel Fuel	350.00	Peaking	Yes
Facility 18	Morrisville	NC	Diesel Fuel	350.00	Peaking	Yes
Facility 19	Clayton	NC	Diesel Fuel	350.00	Peaking	Yes
Facility 20	Cary	NC	Diesel Fuel	350.00	Peaking	Yes
Facility 21	Raleigh	NC	Diesel Fuel	350.00	Peaking	Yes
Facility 22	New Bern	NC	Diesel Fuel	350.00	Peaking	Yes
Facility 23	Atlantic Beach	NC	Diesel Fuel	350.00	Peaking	Yes
Facility 24	Wilmington	NC	Diesel Fuel	350.00	Peaking	Yes
Facility 25	Wilmington	NC	Diesel Fuel	600.00	Peaking	Yes
Facility 26	Morehead City	NC	Diesel Fuel	600.00	Peaking	Yes
Facility 27	Hope Mills	NC	Diesel Fuel	600.00	Peaking	Yes
Facility 28	Wilmington	NC	Diesel Fuel	600.00	Peaking	Yes
Facility 29	Riegelwood	NC	Diesel Fuel	2,700.00	Peaking	Yes
Facility 30	Raleigh	NC	Diesel Fuel	600.00	Peaking	Yes
Facility 31	Tabor City	NC	Diesel Fuel	250.00	Peaking	Yes
Facility 32	Cary	NC	Diesel Fuel	4,000.00	Peaking	Yes
Facility 33	Raleigh	NC	Diesel Fuel	n/a	Peaking	Yes
Facility 34	NASHVILLE	NC	Diesel Fuel	2,250.00	Baseload	Yes
Facility 35	Raleigh	NC	Diesel/ Natural Gas Bi-Fuel	6,000.00	Peaking	Yes
Facility 36	ASHEVILLE	NC	Hydroelectric	2,500.00	Baseload	Yes
Facility 37	Moncure	NC	Hydroelectric	1,500.00	Baseload	Yes
Facility 38	Newdale	NC	Hydroelectric	80.00	Baseload	Yes
Facility 39	Randleman (Cedar Falls)	NC	Hydroelectric	400.00	Baseload	Yes
Facility 40	Coleridge	NC	Hydroelectric	680.00	Baseload	Yes
Facility 41	Troy	NC	Hydroelectric	792.00	Baseload	Yes
Facility 42	High Falls	NC	Hydroelectric	600.00	Baseload	Yes
Facility 43	Troy	NC	Hydroelectric	990.00	Baseload	Yes
Facility 44	Moncure	NC	Hydroelectric	4,400.00	Baseload	Yes
Facility 45	Franklinville	NC	Hydroelectric	550.00	Baseload	Yes
Facility 46	Hope Mills	NC	Hydroelectric	800.00	Baseload	Yes
Facility 47	Jupiter	NC	Hydroelectric	1,000.00	Baseload	Yes
Facility 48	Asheville	NC	Hydroelectric	2,500.00	Baseload	Yes
Facility 49	Bynum	NC	Hydroelectric	500.00	Baseload	Yes
Facility 50	Rocky Mount	NC	Hydroelectric	600.00	Baseload	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 51	Pittsboro	NC	Hydroelectric	310.00	Baseload	Yes
Facility 52	Sampson County	NC	Landfill Gas	6,400.00	Baseload	Yes
Facility 53	Alexander	NC	Landfill Gas	1,415.00	Baseload	Yes
Facility 54	Johnston County	NC	Landfill Gas	1,760.00	Baseload	Yes
Facility 55	Asheville	NC	Landfill Gas	980.00	Baseload	Yes
Facility 56	New Bern	NC	Landfill Gas	4,000.00	Baseload	Yes
Facility 57	Wayne County	NC	Landfill Gas	3,180.00	Baseload	Yes
Facility 58	SOUTHPORT	NC	Natural Gas	46,000.00	Baseload	Yes
Facility 59	Lumberton	NC	Poultry Waste	34,500.00	Baseload	Yes
Facility 60	KENANSVILLE	NC	Poultry Waste	34,500.00	Baseload	Yes
Facility 61	VANCEBORO	NC	Process By -products	27,000.00	Baseload	Yes
Facility 62	RIEGELWOOD	NC	Process By-product	60,000.00	Baseload	Yes
Facility 63	EDWARD	NC	Process By-product	50,000.00	Intermediate/Peaking	Yes
Facility 64	CANTON	NC	Process By-product & Coal	51,000.00	Baseload	Yes
Facility 65	Wake Forest	NC	Solar	1.76	Intermediate/Peaking	Yes
Facility 66	Cary	NC	Solar	2.84	Intermediate/Peaking	Yes
Facility 67	Fairview	NC	Solar	4.24	Intermediate/Peaking	Yes
Facility 68	Sanford	NC	Solar	4.24	Intermediate/Peaking	Yes
Facility 69	Raleigh	NC	Solar	4.77	Intermediate/Peaking	Yes
Facility 70	Pittsboro, NC	NC	Solar	77.00	Intermediate/Peaking	Yes
Facility 71	Asheville	NC	Solar	0.78	Intermediate/Peaking	Yes
Facility 72	Asheville, NC	NC	Solar	11.00	Intermediate/Peaking	Yes
Facility 73	Pittsboro	NC	Solar	1.63	Intermediate/Peaking	Yes
Facility 74	Asheville	NC	Solar	4.29	Intermediate/Peaking	Yes
Facility 75	Chapel Hill	NC	Solar	4.16	Intermediate/Peaking	Yes
Facility 76	Rougemont	NC	Solar	4.12	Intermediate/Peaking	Yes
Facility 77	Raleigh	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 78	Leicester	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 79	Raleigh	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 80	Raleigh	NC	Solar	2.28	Intermediate/Peaking	Yes
Facility 81	Asheville	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 82	Asheville	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 83	Asheville	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 84	Hampstead	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 85	Wake Forest	NC	Solar	1.76	Intermediate/Peaking	Yes
Facility 86	Clyde	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 87	Fairview	NC	Solar	5.85	Intermediate/Peaking	Yes
Facility 88	Cary	NC	Solar	2.60	Intermediate/Peaking	Yes
Facility 89	Raleigh	NC	Solar	3.75	Intermediate/Peaking	Yes
Facility 90	Asheville	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 91	Asheville	NC	Solar	6.80	Intermediate/Peaking	Yes
Facility 92	Morrisville	NC	Solar	2.77	Intermediate/Peaking	Yes
Facility 93	Raleigh	NC	Solar	4.70	Intermediate/Peaking	Yes
Facility 94	Hampstead	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 95	Raleigh	NC	Solar	3.89	Intermediate/Peaking	Yes
Facility 96	Clayton	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 97	Henderson	NC	Solar	5.28	Intermediate/Peaking	Yes
Facility 98	Cary	NC	Solar	7.80	Intermediate/Peaking	Yes
Facility 99	Raleigh	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 100	Raleigh, NC	NC	Solar	27.00	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 101	Raleigh	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 102	Clayton	NC	Solar	3.74	Intermediate/Peaking	Yes
Facility 103	Raleigh	NC	Solar	4.19	Intermediate/Peaking	Yes
Facility 104	Asheville	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 105	Asheville	NC	Solar	3.26	Intermediate/Peaking	Yes
Facility 106	Cary	NC	Solar	5.75	Intermediate/Peaking	Yes
Facility 107	Weaverville	NC	Solar	4.38	Intermediate/Peaking	Yes
Facility 108	Jacksonville	NC	Solar	5.69	Intermediate/Peaking	Yes
Facility 109	Asheville	NC	Solar	6.88	Intermediate/Peaking	Yes
Facility 110	Raleigh, NC	NC	Solar	798.00	Intermediate/Peaking	Yes
Facility 111	Raleigh	NC	Solar	3.20	Intermediate/Peaking	Yes
Facility 112	Southern Pines	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 113	Wilmington	NC	Solar	3.21	Intermediate/Peaking	Yes
Facility 114	Asheville	NC	Solar	3.07	Intermediate/Peaking	Yes
Facility 115	Spruce Pine	NC	Solar	1.00	Intermediate/Peaking	Yes
Facility 116	Clayton	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 117	Boiling Spring Lakes	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 118	Asheville	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 119	Pittsboro	NC	Solar	6.86	Intermediate/Peaking	Yes
Facility 120	Raleigh	NC	Solar	9.05	Intermediate/Peaking	Yes
Facility 121	Carolina Beach	NC	Solar	4.28	Intermediate/Peaking	Yes
Facility 122	Asheville	NC	Solar	3.40	Intermediate/Peaking	Yes
Facility 123	Raleigh	NC	Solar	1.10	Intermediate/Peaking	Yes
Facility 124	Lillington	NC	Solar	3.23	Intermediate/Peaking	Yes
Facility 125	Raleigh	NC	Solar	2.45	Intermediate/Peaking	Yes
Facility 126	Goldsboro	NC	Solar	4.60	Intermediate/Peaking	Yes
Facility 127	Cary	NC	Solar	1.40	Intermediate/Peaking	Yes
Facility 128	Apex	NC	Solar	20.00	Intermediate/Peaking	Yes
Facility 129	Asheville	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 130	OXFORD	NC	Solar	7.40	Intermediate/Peaking	Yes
Facility 131	Asheville	NC	Solar	3.57	Intermediate/Peaking	Yes
Facility 132	Black Mountain	NC	Solar	3.20	Intermediate/Peaking	Yes
Facility 133	Willow Spring	NC	Solar	5.47	Intermediate/Peaking	Yes
Facility 134	Fuquay Varina	NC	Solar	3.90	Intermediate/Peaking	Yes
Facility 135	Fuquay-Varina, NC	NC	Solar	385.00	Intermediate/Peaking	Yes
Facility 136	Pittsboro	NC	Solar	3.23	Intermediate/Peaking	Yes
Facility 137	Cary	NC	Solar	2.19	Intermediate/Peaking	Yes
Facility 138	Pinehurst	NC	Solar	2.88	Intermediate/Peaking	Yes
Facility 139	Pinehurst	NC	Solar	3.21	Intermediate/Peaking	Yes
Facility 140	Asheville	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 141	Asheville	NC	Solar	2.92	Intermediate/Peaking	Yes
Facility 142	Asheville	NC	Solar	5.89	Intermediate/Peaking	Yes
Facility 143	Wilmington	NC	Solar	2.46	Intermediate/Peaking	Yes
Facility 144	Black Mountain	NC	Solar	3.93	Intermediate/Peaking	Yes
Facility 145	Clayton	NC	Solar	3.95	Intermediate/Peaking	Yes
Facility 146	Zebulon	NC	Solar	5.36	Intermediate/Peaking	Yes
Facility 147	Benson	NC	Solar	3.49	Intermediate/Peaking	Yes
Facility 148	Leland	NC	Solar	2.98	Intermediate/Peaking	Yes
Facility 149	Raleigh	NC	Solar	3.14	Intermediate/Peaking	Yes
Facility 150	Baltimore Lake	NC	Solar	6.00	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 151	Fairview	NC	Solar	2.16	Intermediate/Peaking	Yes
Facility 152	Hampstead	NC	Solar	2.30	Intermediate/Peaking	Yes
Facility 153	Sanford	NC	Solar	5.02	Intermediate/Peaking	Yes
Facility 154	Apex	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 155	Raleigh	NC	Solar	2.20	Intermediate/Peaking	Yes
Facility 156	Cary	NC	Solar	5.28	Intermediate/Peaking	Yes
Facility 157	Cary	NC	Solar	3.82	Intermediate/Peaking	Yes
Facility 158	Fayetteville	NC	Solar	4.10	Intermediate/Peaking	Yes
Facility 159	Goldsboro	NC	Solar	4.77	Intermediate/Peaking	Yes
Facility 160	Asheville	NC	Solar	2.38	Intermediate/Peaking	Yes
Facility 161	Wilmington	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 162	Pittsboro	NC	Solar	2.70	Intermediate/Peaking	Yes
Facility 163	Pinehurst	NC	Solar	6.69	Intermediate/Peaking	Yes
Facility 164	Vass	NC	Solar	4.03	Intermediate/Peaking	Yes
Facility 165	Black Mountain	NC	Solar	5.31	Intermediate/Peaking	Yes
Facility 166	Cary	NC	Solar	4.01	Intermediate/Peaking	Yes
Facility 167	Barnardsville	NC	Solar	0.86	Intermediate/Peaking	Yes
Facility 168	Apex	NC	Solar	5.40	Intermediate/Peaking	Yes
Facility 169	Ramseur	NC	Solar	4.50	Intermediate/Peaking	Yes
Facility 170	Holly Springs	NC	Solar	3.32	Intermediate/Peaking	Yes
Facility 171	Asheville	NC	Solar	3.80	Intermediate/Peaking	Yes
Facility 172	Black Mountain	NC	Solar	2.30	Intermediate/Peaking	Yes
Facility 173	Raleigh	NC	Solar	9.02	Intermediate/Peaking	Yes
Facility 174	Wilmington	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 175	Asheville	NC	Solar	5.29	Intermediate/Peaking	Yes
Facility 176	Raleigh	NC	Solar	2.43	Intermediate/Peaking	Yes
Facility 177	Pittsboro	NC	Solar	3.61	Intermediate/Peaking	Yes
Facility 178	Asheville	NC	Solar	1.80	Intermediate/Peaking	Yes
Facility 179	Chapel Hill	NC	Solar	2.67	Intermediate/Peaking	Yes
Facility 180	Fletcher	NC	Solar	1.72	Intermediate/Peaking	Yes
Facility 181	Asheville	NC	Solar	3.85	Intermediate/Peaking	Yes
Facility 182	Sanford	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 183	Bayboro	NC	Solar	9.99	Intermediate/Peaking	Yes
Facility 184	Cary	NC	Solar	3.40	Intermediate/Peaking	Yes
Facility 185	Wilmington	NC	Solar	3.04	Intermediate/Peaking	Yes
Facility 186	Raleigh	NC	Solar	4.40	Intermediate/Peaking	Yes
Facility 187	Chapel Hill	NC	Solar	3.25	Intermediate/Peaking	Yes
Facility 188	Laurinburg	NC	Solar	2.20	Intermediate/Peaking	Yes
Facility 189	Raleigh, NC	NC	Solar	43.00	Intermediate/Peaking	Yes
Facility 190	Candler	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 191	Raleigh, NC	NC	Solar	134.00	Intermediate/Peaking	Yes
Facility 192	Pittsboro	NC	Solar	0.70	Intermediate/Peaking	Yes
Facility 193	Pinehurst	NC	Solar	4.79	Intermediate/Peaking	Yes
Facility 194	Cary	NC	Solar	1.50	Intermediate/Peaking	Yes
Facility 195	Pinehurst	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 196	Black Mountain	NC	Solar	4.68	Intermediate/Peaking	Yes
Facility 197	Wilmington	NC	Solar	2.20	Intermediate/Peaking	Yes
Facility 198	Wilmington	NC	Solar	1.40	Intermediate/Peaking	Yes
Facility 199	Pittsboro	NC	Solar	1.72	Intermediate/Peaking	Yes
Facility 200	Asheboro	NC	Solar	2.58	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 201	Asheville	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 202	Raleigh	NC	Solar	4.34	Intermediate/Peaking	Yes
Facility 203	Cary	NC	Solar	2.72	Intermediate/Peaking	Yes
Facility 204	Asheville	NC	Solar	2.90	Intermediate/Peaking	Yes
Facility 205	Raleigh, NC	NC	Solar	39.00	Intermediate/Peaking	Yes
Facility 206	Raleigh, NC	NC	Solar	19.00	Intermediate/Peaking	Yes
Facility 207	Raleigh	NC	Solar	2.30	Intermediate/Peaking	Yes
Facility 208	Wilmington, NC	NC	Solar	60.00	Intermediate/Peaking	Yes
Facility 209	Wilmington, NC	NC	Solar	24.00	Intermediate/Peaking	Yes
Facility 210	Wilmington	NC	Solar	5.40	Intermediate/Peaking	Yes
Facility 211	Wilmington	NC	Solar	9.60	Intermediate/Peaking	Yes
Facility 212	Franklinton	NC	Solar	3.90	Intermediate/Peaking	Yes
Facility 213	Canton	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 214	Raleigh	NC	Solar	2.02	Intermediate/Peaking	Yes
Facility 215	Pittsboro	NC	Solar	2.72	Intermediate/Peaking	Yes
Facility 216	Hampstead	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 217	Holly Springs	NC	Solar	4.94	Intermediate/Peaking	Yes
Facility 218	Raleigh	NC	Solar	5.22	Intermediate/Peaking	Yes
Facility 219	Barnardsville	NC	Solar	7.60	Intermediate/Peaking	Yes
Facility 220	Raleigh	NC	Solar	5.54	Intermediate/Peaking	Yes
Facility 221	Wilmington, NC	NC	Solar	300.00	Intermediate/Peaking	Yes
Facility 222	Cary	NC	Solar	9.90	Intermediate/Peaking	Yes
Facility 223	Hampstead	NC	Solar	4.20	Intermediate/Peaking	Yes
Facility 224	Morehead City	NC	Solar	2.22	Intermediate/Peaking	Yes
Facility 225	Raleigh	NC	Solar	3.30	Intermediate/Peaking	Yes
Facility 226	Carolina Beach	NC	Solar	2.19	Intermediate/Peaking	Yes
Facility 227	Hampstead	NC	Solar	4.77	Intermediate/Peaking	Yes
Facility 228	Raleigh	NC	Solar	8.00	Intermediate/Peaking	Yes
Facility 229	Mount Olive	NC	Solar	2.26	Intermediate/Peaking	Yes
Facility 230	Raleigh	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 231	Cary	NC	Solar	5.23	Intermediate/Peaking	Yes
Facility 232	Cary	NC	Solar	3.66	Intermediate/Peaking	Yes
Facility 233	Asheville	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 234	Asheville	NC	Solar	4.16	Intermediate/Peaking	Yes
Facility 235	Fairview	NC	Solar	2.88	Intermediate/Peaking	Yes
Facility 236	Asheville	NC	Solar	3.95	Intermediate/Peaking	Yes
Facility 237	Wake Forest	NC	Solar	2.65	Intermediate/Peaking	Yes
Facility 238	Clayton	NC	Solar	3.47	Intermediate/Peaking	Yes
Facility 239	Asheville	NC	Solar	3.38	Intermediate/Peaking	Yes
Facility 240	Raleigh	NC	Solar	4.90	Intermediate/Peaking	Yes
Facility 241	Raleigh	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 242	Laurinburg	NC	Solar	2.10	Intermediate/Peaking	Yes
Facility 243	Pittsboro	NC	Solar	2.88	Intermediate/Peaking	Yes
Facility 244	New Hill	NC	Solar	2.89	Intermediate/Peaking	Yes
Facility 245	Sanford	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 246	Wilmington	NC	Solar	-	Intermediate/Peaking	Yes
Facility 247	Raleigh	NC	Solar	1.50	Intermediate/Peaking	Yes
Facility 248	Raleigh	NC	Solar	3.79	Intermediate/Peaking	Yes
Facility 249	Raleigh, NC	NC	Solar	73.00	Intermediate/Peaking	Yes
Facility 250	Raleigh, NC	NC	Solar	24.00	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 251	Raleigh, NC	NC	Solar	57.00	Intermediate/Peaking	Yes
Facility 252	Asheville	NC	Solar	4.13	Intermediate/Peaking	Yes
Facility 253	Raleigh	NC	Solar	1.92	Intermediate/Peaking	Yes
Facility 254	Asheville	NC	Solar	4.60	Intermediate/Peaking	Yes
Facility 255	Raleigh	NC	Solar	2.94	Intermediate/Peaking	Yes
Facility 256	Asheville	NC	Solar	2.60	Intermediate/Peaking	Yes
Facility 257	Asheville	NC	Solar	4.40	Intermediate/Peaking	Yes
Facility 258	Asheville	NC	Solar	3.80	Intermediate/Peaking	Yes
Facility 259	Castle Hayne, NC	NC	Solar	58.00	Intermediate/Peaking	Yes
Facility 260	Bear Creek	NC	Solar	6.96	Intermediate/Peaking	Yes
Facility 261	Chandler	NC	Solar	0.70	Intermediate/Peaking	Yes
Facility 262	Asheville	NC	Solar	5.88	Intermediate/Peaking	Yes
Facility 263	Raleigh	NC	Solar	1.76	Intermediate/Peaking	Yes
Facility 264	Angier	NC	Solar	1.72	Intermediate/Peaking	Yes
Facility 265	Wilmington	NC	Solar	2.45	Intermediate/Peaking	Yes
Facility 266	Pinehurst	NC	Solar	4.43	Intermediate/Peaking	Yes
Facility 267	Raeford	NC	Solar	7.24	Intermediate/Peaking	Yes
Facility 268	Arden	NC	Solar	2.52	Intermediate/Peaking	Yes
Facility 269	Garner	NC	Solar	4.25	Intermediate/Peaking	Yes
Facility 270	Leicester	NC	Solar	9.69	Intermediate/Peaking	Yes
Facility 271	Cary	NC	Solar	5.39	Intermediate/Peaking	Yes
Facility 272	Barnardsville	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 273	Louisburg	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 274	Asheville	NC	Solar	2.06	Intermediate/Peaking	Yes
Facility 275	Carolina Beach	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 276	Fairview	NC	Solar	5.33	Intermediate/Peaking	Yes
Facility 277	Raleigh	NC	Solar	-	Intermediate/Peaking	Yes
Facility 278	Weaverville	NC	Solar	4.52	Intermediate/Peaking	Yes
Facility 279	Wilmington	NC	Solar	3.69	Intermediate/Peaking	Yes
Facility 280	Chapel Hill	NC	Solar	2.32	Intermediate/Peaking	Yes
Facility 281	Waynesville	NC	Solar	2.88	Intermediate/Peaking	Yes
Facility 282	Smithfield	NC	Solar	5.48	Intermediate/Peaking	Yes
Facility 283	Hampstead	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 284	Arden	NC	Solar	5.32	Intermediate/Peaking	Yes
Facility 285	Morehead City	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 286	Cary	NC	Solar	5.08	Intermediate/Peaking	Yes
Facility 287	Sanford	NC	Solar	5.60	Intermediate/Peaking	Yes
Facility 288	Morehead City	NC	Solar	2.54	Intermediate/Peaking	Yes
Facility 289	Alexander	NC	Solar	2.01	Intermediate/Peaking	Yes
Facility 290	Weaverville	NC	Solar	6.18	Intermediate/Peaking	Yes
Facility 291	Bald Head Island	NC	Solar	4.63	Intermediate/Peaking	Yes
Facility 292	Asheville	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 293	Raleigh	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 294	Southern Pines	NC	Solar	4.34	Intermediate/Peaking	Yes
Facility 295	Raleigh	NC	Solar	8.00	Intermediate/Peaking	Yes
Facility 296	Raleigh	NC	Solar	3.13	Intermediate/Peaking	Yes
Facility 297	Raleigh	NC	Solar	5.30	Intermediate/Peaking	Yes
Facility 298	Arden	NC	Solar	7.22	Intermediate/Peaking	Yes
Facility 299	Asheville	NC	Solar	7.35	Intermediate/Peaking	Yes
Facility 300	Asheville	NC	Solar	3.50	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 301	Asheville	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 302	Pinehurst	NC	Solar	4.82	Intermediate/Peaking	Yes
Facility 303	Garner	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 304	Cary	NC	Solar	2.64	Intermediate/Peaking	Yes
Facility 305	Candler	NC	Solar	5.34	Intermediate/Peaking	Yes
Facility 306	Raleigh	NC	Solar	9.90	Intermediate/Peaking	Yes
Facility 307	Asheville	NC	Solar	2.90	Intermediate/Peaking	Yes
Facility 308	Weaverville	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 309	Burnsville	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 310	Wendell	NC	Solar	4.10	Intermediate/Peaking	Yes
Facility 311	Raleigh	NC	Solar	4.13	Intermediate/Peaking	Yes
Facility 312	Apex	NC	Solar	4.12	Intermediate/Peaking	Yes
Facility 313	Chapel Hill	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 314	Asheville	NC	Solar	3.70	Intermediate/Peaking	Yes
Facility 315	Asheville	NC	Solar	2.65	Intermediate/Peaking	Yes
Facility 316	Asheville	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 317	Apex	NC	Solar	4.13	Intermediate/Peaking	Yes
Facility 318	Pittsboro	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 319	Raleigh	NC	Solar	3.29	Intermediate/Peaking	Yes
Facility 320	Raleigh	NC	Solar	5.03	Intermediate/Peaking	Yes
Facility 321	Raleigh	NC	Solar	3.30	Intermediate/Peaking	Yes
Facility 322	Sanford	NC	Solar	4.38	Intermediate/Peaking	Yes
Facility 323	Eagle Springs	NC	Solar	4.12	Intermediate/Peaking	Yes
Facility 324	Pinehurst	NC	Solar	5.04	Intermediate/Peaking	Yes
Facility 325	Candler	NC	Solar	9.50	Intermediate/Peaking	Yes
Facility 326	Chapel Hill	NC	Solar	2.01	Intermediate/Peaking	Yes
Facility 327	Pinehurst	NC	Solar	2.29	Intermediate/Peaking	Yes
Facility 328	Wilmington	NC	Solar	2.75	Intermediate/Peaking	Yes
Facility 329	Raleigh	NC	Solar	6.05	Intermediate/Peaking	Yes
Facility 330	Asheville	NC	Solar	3.50	Intermediate/Peaking	Yes
Facility 331	Southport	NC	Solar	2.33	Intermediate/Peaking	Yes
Facility 332	Black Mountain	NC	Solar	4.27	Intermediate/Peaking	Yes
Facility 333	Raleigh	NC	Solar	3.98	Intermediate/Peaking	Yes
Facility 334	Asheboro	NC	Solar	4.10	Intermediate/Peaking	Yes
Facility 335	Asheville	NC	Solar	3.14	Intermediate/Peaking	Yes
Facility 336	Wilmington	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 337	Raleigh	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 338	Fuquay Varina	NC	Solar	6.53	Intermediate/Peaking	Yes
Facility 339	Zebulon	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 340	Chapel Hill	NC	Solar	1.20	Intermediate/Peaking	Yes
Facility 341	Chapel Hill	NC	Solar	3.25	Intermediate/Peaking	Yes
Facility 342	Raleigh	NC	Solar	3.54	Intermediate/Peaking	Yes
Facility 343	Asheville	NC	Solar	2.93	Intermediate/Peaking	Yes
Facility 344	Swansboro	NC	Solar	2.10	Intermediate/Peaking	Yes
Facility 345	Wilmington	NC	Solar	5.24	Intermediate/Peaking	Yes
Facility 346	Cary	NC	Solar	4.70	Intermediate/Peaking	Yes
Facility 347	Morrisville	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 348	Asheville	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 349	Raleigh	NC	Solar	4.46	Intermediate/Peaking	Yes
Facility 350	Zebulon	NC	Solar	5.68	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 351	Leicester	NC	Solar	4.61	Intermediate/Peaking	Yes
Facility 352	Leland	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 353	Wilmington	NC	Solar	3.74	Intermediate/Peaking	Yes
Facility 354	Roxboro	NC	Solar	3.31	Intermediate/Peaking	Yes
Facility 355	Spring Hope	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 356	Garner	NC	Solar	6.02	Intermediate/Peaking	Yes
Facility 357	Asheville	NC	Solar	3.80	Intermediate/Peaking	Yes
Facility 358	Fairview	NC	Solar	2.80	Intermediate/Peaking	Yes
Facility 359	Weaverville	NC	Solar	3.68	Intermediate/Peaking	Yes
Facility 360	Wilmington	NC	Solar	5.90	Intermediate/Peaking	Yes
Facility 361	Willard	NC	Solar	4.07	Intermediate/Peaking	Yes
Facility 362	Raleigh	NC	Solar	2.03	Intermediate/Peaking	Yes
Facility 363	Cary	NC	Solar	3.93	Intermediate/Peaking	Yes
Facility 364	Knightdale	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 365	Wilmington	NC	Solar	4.82	Intermediate/Peaking	Yes
Facility 366	Apex	NC	Solar	5.64	Intermediate/Peaking	Yes
Facility 367	Fletcher	NC	Solar	6.45	Intermediate/Peaking	Yes
Facility 368	Raleigh	NC	Solar	4.25	Intermediate/Peaking	Yes
Facility 369	Wilmington	NC	Solar	4.42	Intermediate/Peaking	Yes
Facility 370	Chapel Hill	NC	Solar	4.52	Intermediate/Peaking	Yes
Facility 371	Rocky Point	NC	Solar	2.67	Intermediate/Peaking	Yes
Facility 372	Pittsboro	NC	Solar	3.43	Intermediate/Peaking	Yes
Facility 373	Pittsboro	NC	Solar	6.93	Intermediate/Peaking	Yes
Facility 374	Chapel Hill	NC	Solar	5.39	Intermediate/Peaking	Yes
Facility 375	Raleigh	NC	Solar	2.60	Intermediate/Peaking	Yes
Facility 376	Zebulon	NC	Solar	5.50	Intermediate/Peaking	Yes
Facility 377	Raleigh	NC	Solar	2.72	Intermediate/Peaking	Yes
Facility 378	Holly Springs	NC	Solar	4.10	Intermediate/Peaking	Yes
Facility 379	West End	NC	Solar	4.93	Intermediate/Peaking	Yes
Facility 380	Raleigh	NC	Solar	4.21	Intermediate/Peaking	Yes
Facility 381	Bahama	NC	Solar	3.66	Intermediate/Peaking	Yes
Facility 382	Morrisville	NC	Solar	3.49	Intermediate/Peaking	Yes
Facility 383	Hampstead	NC	Solar	3.09	Intermediate/Peaking	Yes
Facility 384	Asheville	NC	Solar	4.25	Intermediate/Peaking	Yes
Facility 385	Raleigh	NC	Solar	4.59	Intermediate/Peaking	Yes
Facility 386	Raleigh	NC	Solar	7.70	Intermediate/Peaking	Yes
Facility 387	Cary	NC	Solar	4.42	Intermediate/Peaking	Yes
Facility 388	Wilmington	NC	Solar	5.18	Intermediate/Peaking	Yes
Facility 389	Raleigh	NC	Solar	3.49	Intermediate/Peaking	Yes
Facility 390	Asheville	NC	Solar	2.06	Intermediate/Peaking	Yes
Facility 391	Raleigh	NC	Solar	5.61	Intermediate/Peaking	Yes
Facility 392	Hampstead	NC	Solar	4.75	Intermediate/Peaking	Yes
Facility 393	Calypso	NC	Solar	5.59	Intermediate/Peaking	Yes
Facility 394	Pinehurst	NC	Solar	3.86	Intermediate/Peaking	Yes
Facility 395	Weaverville	NC	Solar	7.34	Intermediate/Peaking	Yes
Facility 396	Asheville	NC	Solar	4.80	Intermediate/Peaking	Yes
Facility 397	Wilmington	NC	Solar	2.80	Intermediate/Peaking	Yes
Facility 398	Wendell	NC	Solar	4.33	Intermediate/Peaking	Yes
Facility 399	Bailey	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 400	Knightdale	NC	Solar	2.95	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 401	Asheville	NC	Solar	4.32	Intermediate/Peaking	Yes
Facility 402	Clyde	NC	Solar	-	Intermediate/Peaking	Yes
Facility 403	Raleigh	NC	Solar	3.53	Intermediate/Peaking	Yes
Facility 404	Asheville	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 405	Raleigh	NC	Solar	2.18	Intermediate/Peaking	Yes
Facility 406	Kure Beach	NC	Solar	2.44	Intermediate/Peaking	Yes
Facility 407	Arden	NC	Solar	1.44	Intermediate/Peaking	Yes
Facility 408	Wilmington	NC	Solar	5.06	Intermediate/Peaking	Yes
Facility 409	Raleigh	NC	Solar	3.46	Intermediate/Peaking	Yes
Facility 410	Wilmington	NC	Solar	2.81	Intermediate/Peaking	Yes
Facility 411	Biltmore Lake	NC	Solar	3.49	Intermediate/Peaking	Yes
Facility 412	Asheville	NC	Solar	2.25	Intermediate/Peaking	Yes
Facility 413	Spruce Pine, NC	NC	Solar	17.00	Intermediate/Peaking	Yes
Facility 414	Wilmington	NC	Solar	6.28	Intermediate/Peaking	Yes
Facility 415	Pittsboro	NC	Solar	3.73	Intermediate/Peaking	Yes
Facility 416	Asheville	NC	Solar	5.32	Intermediate/Peaking	Yes
Facility 417	Willow Spring	NC	Solar	3.76	Intermediate/Peaking	Yes
Facility 418	Raleigh	NC	Solar	7.09	Intermediate/Peaking	Yes
Facility 419	Linden	NC	Solar	4.20	Intermediate/Peaking	Yes
Facility 420	Raleigh	NC	Solar	3.67	Intermediate/Peaking	Yes
Facility 421	Asheville	NC	Solar	4.26	Intermediate/Peaking	Yes
Facility 422	Smyrna	NC	Solar	2.19	Intermediate/Peaking	Yes
Facility 423	Cary	NC	Solar	5.80	Intermediate/Peaking	Yes
Facility 424	Clayton	NC	Solar	3.50	Intermediate/Peaking	Yes
Facility 425	Alexander	NC	Solar	3.40	Intermediate/Peaking	Yes
Facility 426	Raleigh	NC	Solar	4.90	Intermediate/Peaking	Yes
Facility 427	Chapel Hill	NC	Solar	3.53	Intermediate/Peaking	Yes
Facility 428	Holly Springs	NC	Solar	5.10	Intermediate/Peaking	Yes
Facility 429	Raleigh	NC	Solar	2.46	Intermediate/Peaking	Yes
Facility 430	Candler	NC	Solar	2.19	Intermediate/Peaking	Yes
Facility 431	Carolina Beach	NC	Solar	6.91	Intermediate/Peaking	Yes
Facility 432	Oxford, NC	NC	Solar	200.00	Intermediate/Peaking	Yes
Facility 433	Williston	NC	Solar	7.90	Intermediate/Peaking	Yes
Facility 434	Carolina Beach	NC	Solar	1.00	Intermediate/Peaking	Yes
Facility 435	Asheboro	NC	Solar	5.34	Intermediate/Peaking	Yes
Facility 436	Cary	NC	Solar	3.40	Intermediate/Peaking	Yes
Facility 437	Pittsboro	NC	Solar	1.63	Intermediate/Peaking	Yes
Facility 438	Morrisville	NC	Solar	4.07	Intermediate/Peaking	Yes
Facility 439	Fletcher	NC	Solar	3.85	Intermediate/Peaking	Yes
Facility 440	Cary	NC	Solar	2.94	Intermediate/Peaking	Yes
Facility 441	Wilmington	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 442	Wilmington	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 443	Candler	NC	Solar	3.36	Intermediate/Peaking	Yes
Facility 444	Pittsboro	NC	Solar	1.80	Intermediate/Peaking	Yes
Facility 445	Black Mountain	NC	Solar	2.75	Intermediate/Peaking	Yes
Facility 446	Fuquay-Varina	NC	Solar	6.57	Intermediate/Peaking	Yes
Facility 447	Fremont	NC	Solar	1.54	Intermediate/Peaking	Yes
Facility 448	Fletcher	NC	Solar	3.67	Intermediate/Peaking	Yes
Facility 449	Fletcher	NC	Solar	9.48	Intermediate/Peaking	Yes
Facility 450	Boiling Spring Lakes	NC	Solar	2.48	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 451	Weaverville	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 452	Asheville	NC	Solar	7.50	Intermediate/Peaking	Yes
Facility 453	Pittsboro	NC	Solar	3.02	Intermediate/Peaking	Yes
Facility 454	Cary	NC	Solar	1.50	Intermediate/Peaking	Yes
Facility 455	Asheville	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 456	Wilmington	NC	Solar	1.80	Intermediate/Peaking	Yes
Facility 457	Raleigh	NC	Solar	1.80	Intermediate/Peaking	Yes
Facility 458	Garner	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 459	Manson	NC	Solar	3.88	Intermediate/Peaking	Yes
Facility 460	Cary	NC	Solar	5.92	Intermediate/Peaking	Yes
Facility 461	Cary	NC	Solar	1.50	Intermediate/Peaking	Yes
Facility 462	Fuquay Varina	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 463	Asheville	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 464	Weaverville	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 465	Chapel Hill	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 466	Wake Forest	NC	Solar	2.35	Intermediate/Peaking	Yes
Facility 467	Raleigh	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 468	Raleigh	NC	Solar	2.70	Intermediate/Peaking	Yes
Facility 469	Alexander	NC	Solar	2.80	Intermediate/Peaking	Yes
Facility 470	Barnardsville	NC	Solar	3.64	Intermediate/Peaking	Yes
Facility 471	Bakersville	NC	Solar	3.20	Intermediate/Peaking	Yes
Facility 472	Pittsboro	NC	Solar	1.63	Intermediate/Peaking	Yes
Facility 473	Asheville	NC	Solar	1.60	Intermediate/Peaking	Yes
Facility 474	Raleigh	NC	Solar	3.67	Intermediate/Peaking	Yes
Facility 475	Cary	NC	Solar	2.30	Intermediate/Peaking	Yes
Facility 476	Weaverville	NC	Solar	3.96	Intermediate/Peaking	Yes
Facility 477	Wilmington	NC	Solar	1.00	Intermediate/Peaking	Yes
Facility 478	Asheville	NC	Solar	4.25	Intermediate/Peaking	Yes
Facility 479	Fairview	NC	Solar	2.70	Intermediate/Peaking	Yes
Facility 480	Hampstead	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 481	Canton	NC	Solar	9.18	Intermediate/Peaking	Yes
Facility 482	Asheville	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 483	Raleigh	NC	Solar	1.50	Intermediate/Peaking	Yes
Facility 484	Raleigh	NC	Solar	2.76	Intermediate/Peaking	Yes
Facility 485	Asheville	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 486	Cary	NC	Solar	3.98	Intermediate/Peaking	Yes
Facility 487	Leland	NC	Solar	5.89	Intermediate/Peaking	Yes
Facility 488	Raleigh	NC	Solar	1.72	Intermediate/Peaking	Yes
Facility 489	Asheville	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 490	Asheville	NC	Solar	1.80	Intermediate/Peaking	Yes
Facility 491	Barnardsville	NC	Solar	1.92	Intermediate/Peaking	Yes
Facility 492	Cameron	NC	Solar	8.60	Intermediate/Peaking	Yes
Facility 493	Southern Pines	NC	Solar	7.80	Intermediate/Peaking	Yes
Facility 494	Asheville	NC	Solar	1.73	Intermediate/Peaking	Yes
Facility 495	Raleigh	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 496	Raleigh	NC	Solar	3.15	Intermediate/Peaking	Yes
Facility 497	Raleigh	NC	Solar	5.50	Intermediate/Peaking	Yes
Facility 498	Raleigh	NC	Solar	9.99	Intermediate/Peaking	Yes
Facility 499	Pinehurst	NC	Solar	8.20	Intermediate/Peaking	Yes
Facility 500	Alexander	NC	Solar	3.10	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 501	Pinehurst	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 502	Candler	NC	Solar	2.26	Intermediate/Peaking	Yes
Facility 503	Morehead City	NC	Solar	2.04	Intermediate/Peaking	Yes
Facility 504	Raleigh	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 505	Pittsboro	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 506	Pittsboro	NC	Solar	1.70	Intermediate/Peaking	Yes
Facility 507	Carolina Beach	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 508	Biscoe	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 509	Wade	NC	Solar	7.16	Intermediate/Peaking	Yes
Facility 510	Asheville	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 511	Clyde	NC	Solar	2.88	Intermediate/Peaking	Yes
Facility 512	Raleigh	NC	Solar	1.80	Intermediate/Peaking	Yes
Facility 513	Wilmington	NC	Solar	1.44	Intermediate/Peaking	Yes
Facility 514	Raleigh	NC	Solar	4.43	Intermediate/Peaking	Yes
Facility 515	Raleigh	NC	Solar	2.39	Intermediate/Peaking	Yes
Facility 516	Cary	NC	Solar	2.92	Intermediate/Peaking	Yes
Facility 517	Broadway	NC	Solar	5.83	Intermediate/Peaking	Yes
Facility 518	Asheville	NC	Solar	4.40	Intermediate/Peaking	Yes
Facility 519	Cary	NC	Solar	4.29	Intermediate/Peaking	Yes
Facility 520	Fuquay Varina	NC	Solar	14.56	Intermediate/Peaking	Yes
Facility 521	Carthage	NC	Solar	5.71	Intermediate/Peaking	Yes
Facility 522	Fletcher	NC	Solar	7.36	Intermediate/Peaking	Yes
Facility 523	Kure Beach	NC	Solar	2.56	Intermediate/Peaking	Yes
Facility 524	Apex	NC	Solar	5.05	Intermediate/Peaking	Yes
Facility 525	Raleigh	NC	Solar	3.92	Intermediate/Peaking	Yes
Facility 526	Hampstead	NC	Solar	5.73	Intermediate/Peaking	Yes
Facility 527	Cary	NC	Solar	2.14	Intermediate/Peaking	Yes
Facility 528	Cary	NC	Solar	4.39	Intermediate/Peaking	Yes
Facility 529	Pinehurst	NC	Solar	4.58	Intermediate/Peaking	Yes
Facility 530	Vass	NC	Solar	8.58	Intermediate/Peaking	Yes
Facility 531	Pittsboro	NC	Solar	3.52	Intermediate/Peaking	Yes
Facility 532	Wilmington	NC	Solar	4.54	Intermediate/Peaking	Yes
Facility 533	Pittsboro	NC	Solar	4.86	Intermediate/Peaking	Yes
Facility 534	Asheville	NC	Solar	4.65	Intermediate/Peaking	Yes
Facility 535	Pittsboro	NC	Solar	5.12	Intermediate/Peaking	Yes
Facility 536	Wilmington	NC	Solar	5.26	Intermediate/Peaking	Yes
Facility 537	Raleigh	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 538	Asheville	NC	Solar	2.10	Intermediate/Peaking	Yes
Facility 539	Chapel Hill	NC	Solar	2.46	Intermediate/Peaking	Yes
Facility 540	Weaverville, NC	NC	Solar	42.00	Intermediate/Peaking	Yes
Facility 541	Arden	NC	Solar	4.36	Intermediate/Peaking	Yes
Facility 542	Apex	NC	Solar	4.60	Intermediate/Peaking	Yes
Facility 543	Raleigh	NC	Solar	5.62	Intermediate/Peaking	Yes
Facility 544	Zebulon	NC	Solar	1.60	Intermediate/Peaking	Yes
Facility 545	Chapel Hill	NC	Solar	1.00	Intermediate/Peaking	Yes
Facility 546	Asheville	NC	Solar	4.80	Intermediate/Peaking	Yes
Facility 547	Pittsboro	NC	Solar	3.04	Intermediate/Peaking	Yes
Facility 548	Lillington	NC	Solar	2.25	Intermediate/Peaking	Yes
Facility 549	Asheville	NC	Solar	3.84	Intermediate/Peaking	Yes
Facility 550	Asheville	NC	Solar	2.90	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 551	Raleigh	NC	Solar	5.32	Intermediate/Peaking	Yes
Facility 552	Chapel Hill	NC	Solar	4.62	Intermediate/Peaking	Yes
Facility 553	Raleigh	NC	Solar	6.21	Intermediate/Peaking	Yes
Facility 554	Black Mountain	NC	Solar	1.92	Intermediate/Peaking	Yes
Facility 555	Wilmington	NC	Solar	4.61	Intermediate/Peaking	Yes
Facility 556	Raleigh	NC	Solar	5.39	Intermediate/Peaking	Yes
Facility 557	Raleigh	NC	Solar	2.30	Intermediate/Peaking	Yes
Facility 558	Cary	NC	Solar	3.71	Intermediate/Peaking	Yes
Facility 559	Sanford	NC	Solar	3.83	Intermediate/Peaking	Yes
Facility 560	Apex	NC	Solar	9.80	Intermediate/Peaking	Yes
Facility 561	Wilmington	NC	Solar	4.02	Intermediate/Peaking	Yes
Facility 562	Wilmington	NC	Solar	4.57	Intermediate/Peaking	Yes
Facility 563	Asheville	NC	Solar	0.80	Intermediate/Peaking	Yes
Facility 564	Wilmington	NC	Solar	4.09	Intermediate/Peaking	Yes
Facility 565	Asheville	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 566	Fayetteville	NC	Solar	3.87	Intermediate/Peaking	Yes
Facility 567	Raleigh	NC	Solar	4.22	Intermediate/Peaking	Yes
Facility 568	Apex	NC	Solar	7.19	Intermediate/Peaking	Yes
Facility 569	Kenly, NC	NC	Solar	75.00	Intermediate/Peaking	Yes
Facility 570	Kenly, NC	NC	Solar	123.00	Intermediate/Peaking	Yes
Facility 571	Raleigh	NC	Solar	4.35	Intermediate/Peaking	Yes
Facility 572	Hampstead	NC	Solar	6.27	Intermediate/Peaking	Yes
Facility 573	Fayetteville	NC	Solar	3.27	Intermediate/Peaking	Yes
Facility 574	Cameron	NC	Solar	4.70	Intermediate/Peaking	Yes
Facility 575	Raleigh	NC	Solar	1.72	Intermediate/Peaking	Yes
Facility 576	Knightdale	NC	Solar	2.82	Intermediate/Peaking	Yes
Facility 577	Cary	NC	Solar	1.50	Intermediate/Peaking	Yes
Facility 578	Weaverville	NC	Solar	1.00	Intermediate/Peaking	Yes
Facility 579	Raleigh	NC	Solar	1.80	Intermediate/Peaking	Yes
Facility 580	Fletcher, NC	NC	Solar	20.00	Intermediate/Peaking	Yes
Facility 581	Asheville	NC	Solar	4.13	Intermediate/Peaking	Yes
Facility 582	Angier	NC	Solar	7.50	Intermediate/Peaking	Yes
Facility 583	Raleigh	NC	Solar	2.90	Intermediate/Peaking	Yes
Facility 584	Raleigh	NC	Solar	5.29	Intermediate/Peaking	Yes
Facility 585	Wake Forest	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 586	Apex	NC	Solar	3.41	Intermediate/Peaking	Yes
Facility 587	Clayton	NC	Solar	4.62	Intermediate/Peaking	Yes
Facility 588	Wilmington	NC	Solar	4.89	Intermediate/Peaking	Yes
Facility 589	Asheville	NC	Solar	5.01	Intermediate/Peaking	Yes
Facility 590	Asheville	NC	Solar	3.80	Intermediate/Peaking	Yes
Facility 591	Asheville	NC	Solar	4.68	Intermediate/Peaking	Yes
Facility 592	Asheville	NC	Solar	2.24	Intermediate/Peaking	Yes
Facility 593	Hot Springs	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 594	Weaverville	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 595	Asheville	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 596	Raleigh	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 597	Raleigh	NC	Solar	3.67	Intermediate/Peaking	Yes
Facility 598	Candler	NC	Solar	6.10	Intermediate/Peaking	Yes
Facility 599	Apex	NC	Solar	4.28	Intermediate/Peaking	Yes
Facility 600	Asheville	NC	Solar	3.80	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 601	Asheville	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 602	Wilmington	NC	Solar	3.40	Intermediate/Peaking	Yes
Facility 603	Sanford	NC	Solar	4.64	Intermediate/Peaking	Yes
Facility 604	New Bern	NC	Solar	4.43	Intermediate/Peaking	Yes
Facility 605	Wilmington	NC	Solar	2.39	Intermediate/Peaking	Yes
Facility 606	Wilmington	NC	Solar	2.60	Intermediate/Peaking	Yes
Facility 607	Weaverville	NC	Solar	4.94	Intermediate/Peaking	Yes
Facility 608	Asheville	NC	Solar	3.01	Intermediate/Peaking	Yes
Facility 609	Asheville	NC	Solar	2.82	Intermediate/Peaking	Yes
Facility 610	Asheville	NC	Solar	2.02	Intermediate/Peaking	Yes
Facility 611	Cary, NC	NC	Solar	552.00	Intermediate/Peaking	Yes
Facility 612	Raleigh	NC	Solar	2.64	Intermediate/Peaking	Yes
Facility 613	Siler City	NC	Solar	2.65	Intermediate/Peaking	Yes
Facility 614	Angier	NC	Solar	4.47	Intermediate/Peaking	Yes
Facility 615	Raleigh	NC	Solar	5.70	Intermediate/Peaking	Yes
Facility 616	Leland	NC	Solar	3.42	Intermediate/Peaking	Yes
Facility 617	Hampstead	NC	Solar	4.33	Intermediate/Peaking	Yes
Facility 618	Alexander	NC	Solar	1.53	Intermediate/Peaking	Yes
Facility 619	Holly Springs	NC	Solar	1.60	Intermediate/Peaking	Yes
Facility 620	Holly Springs	NC	Solar	1.80	Intermediate/Peaking	Yes
Facility 621	Morehead City	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 622	Pittsboro	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 623	Asheville	NC	Solar	4.47	Intermediate/Peaking	Yes
Facility 624	Wilmington	NC	Solar	5.34	Intermediate/Peaking	Yes
Facility 625	Hamptead	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 626	Apex	NC	Solar	1.10	Intermediate/Peaking	Yes
Facility 627	Clayton	NC	Solar	5.89	Intermediate/Peaking	Yes
Facility 628	Cary	NC	Solar	3.78	Intermediate/Peaking	Yes
Facility 629	Pinehurst	NC	Solar	4.90	Intermediate/Peaking	Yes
Facility 630	Asheville	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 631	Fletcher	NC	Solar	7.60	Intermediate/Peaking	Yes
Facility 632	Raleigh	NC	Solar	3.68	Intermediate/Peaking	Yes
Facility 633	Asheville	NC	Solar	4.04	Intermediate/Peaking	Yes
Facility 634	Apex	NC	Solar	4.81	Intermediate/Peaking	Yes
Facility 635		NC	Solar	273.00	Intermediate/Peaking	Yes
Facility 636	Asheville	NC	Solar	2.92	Intermediate/Peaking	Yes
Facility 637	Raleigh	NC	Solar	3.02	Intermediate/Peaking	Yes
Facility 638	Goldsboro	NC	Solar	4.61	Intermediate/Peaking	Yes
Facility 639	Raleigh	NC	Solar	4.82	Intermediate/Peaking	Yes
Facility 640	Wilmington	NC	Solar	3.50	Intermediate/Peaking	Yes
Facility 641	Beaufort	NC	Solar	2.59	Intermediate/Peaking	Yes
Facility 642	Wilmington	NC	Solar	5.23	Intermediate/Peaking	Yes
Facility 643	Holly Springs	NC	Solar	3.75	Intermediate/Peaking	Yes
Facility 644	Asheville	NC	Solar	5.15	Intermediate/Peaking	Yes
Facility 645	Cary	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 646	Garner	NC	Solar	3.95	Intermediate/Peaking	Yes
Facility 647	Cary	NC	Solar	6.34	Intermediate/Peaking	Yes
Facility 648	Asheville	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 649	Asheville	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 650	Raleigh	NC	Solar	2.90	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 651	Raleigh	NC	Solar	1.80	Intermediate/Peaking	Yes
Facility 652	Garner	NC	Solar	4.26	Intermediate/Peaking	Yes
Facility 653	Raleigh	NC	Solar	3.73	Intermediate/Peaking	Yes
Facility 654	Wilmington	NC	Solar	4.92	Intermediate/Peaking	Yes
Facility 655	Wilmington	NC	Solar	3.58	Intermediate/Peaking	Yes
Facility 656	Apex	NC	Solar	3.10	Intermediate/Peaking	Yes
Facility 657	Wilmington, NC	NC	Solar	46.00	Intermediate/Peaking	Yes
Facility 658	Clayton	NC	Solar	4.20	Intermediate/Peaking	Yes
Facility 659	Raleigh	NC	Solar	2.37	Intermediate/Peaking	Yes
Facility 660	West End	NC	Solar	4.28	Intermediate/Peaking	Yes
Facility 661	Asheville	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 662	Semora	NC	Solar	3.59	Intermediate/Peaking	Yes
Facility 663	Raleigh	NC	Solar	3.40	Intermediate/Peaking	Yes
Facility 664	Henderson	NC	Solar	5.54	Intermediate/Peaking	Yes
Facility 665	Wilmington	NC	Solar	2.28	Intermediate/Peaking	Yes
Facility 666	Wilmington	NC	Solar	3.42	Intermediate/Peaking	Yes
Facility 667	Jacksonville	NC	Solar	4.60	Intermediate/Peaking	Yes
Facility 668	Cary	NC	Solar	3.61	Intermediate/Peaking	Yes
Facility 669	Asheville	NC	Solar	7.28	Intermediate/Peaking	Yes
Facility 670	Asheville	NC	Solar	4.76	Intermediate/Peaking	Yes
Facility 671	Angier	NC	Solar	4.76	Intermediate/Peaking	Yes
Facility 672	Raleigh	NC	Solar	2.55	Intermediate/Peaking	Yes
Facility 673	Raleigh	NC	Solar	1.50	Intermediate/Peaking	Yes
Facility 674	Wilmington	NC	Solar	2.59	Intermediate/Peaking	Yes
Facility 675	Asheville	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 676	Chapel Hill	NC	Solar	6.79	Intermediate/Peaking	Yes
Facility 677	Carolina Beach	NC	Solar	4.39	Intermediate/Peaking	Yes
Facility 678	Arden	NC	Solar	6.20	Intermediate/Peaking	Yes
Facility 679	Cary	NC	Solar	1.72	Intermediate/Peaking	Yes
Facility 680	Pinehurst	NC	Solar	3.14	Intermediate/Peaking	Yes
Facility 681	Garner	NC	Solar	6.33	Intermediate/Peaking	Yes
Facility 682	Asheville	NC	Solar	2.80	Intermediate/Peaking	Yes
Facility 683	Raleigh	NC	Solar	3.04	Intermediate/Peaking	Yes
Facility 684	Raleigh	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 685	Cary	NC	Solar	4.10	Intermediate/Peaking	Yes
Facility 686	Rocky Point	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 687	Barnardsville	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 688	Cary	NC	Solar	4.97	Intermediate/Peaking	Yes
Facility 689	Willow Spring	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 690	Candler	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 691	Asheville	NC	Solar	3.40	Intermediate/Peaking	Yes
Facility 692	Asheville	NC	Solar	3.40	Intermediate/Peaking	Yes
Facility 693	Barnardsville	NC	Solar	4.60	Intermediate/Peaking	Yes
Facility 694	Raleigh	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 695	Asheville	NC	Solar	3.14	Intermediate/Peaking	Yes
Facility 696	Zebulon	NC	Solar	1.14	Intermediate/Peaking	Yes
Facility 697	Four Oaks	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 698	Weaverville	NC	Solar	4.08	Intermediate/Peaking	Yes
Facility 699	Pittsboro	NC	Solar	1.49	Intermediate/Peaking	Yes
Facility 700	Asheville	NC	Solar	1.00	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 701	Wilmington	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 702	Siler City	NC	Solar	8.64	Intermediate/Peaking	Yes
Facility 703	Wilmington	NC	Solar	2.60	Intermediate/Peaking	Yes
Facility 704	Wilmington	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 705	Fuquay Varina	NC	Solar	3.50	Intermediate/Peaking	Yes
Facility 706	Raleigh	NC	Solar	2.45	Intermediate/Peaking	Yes
Facility 707	Pinehurst	NC	Solar	5.09	Intermediate/Peaking	Yes
Facility 708	Beaufort	NC	Solar	2.06	Intermediate/Peaking	Yes
Facility 709	Holly Springs	NC	Solar	6.95	Intermediate/Peaking	Yes
Facility 710	Pittsboro, NC	NC	Solar	11.00	Intermediate/Peaking	Yes
Facility 711	Asheville	NC	Solar	1.00	Intermediate/Peaking	Yes
Facility 712	Southern Pines	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 713	Asheville	NC	Solar	4.84	Intermediate/Peaking	Yes
Facility 714	Raleigh	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 715	Leland	NC	Solar	4.89	Intermediate/Peaking	Yes
Facility 716	Raleigh	NC	Solar	4.90	Intermediate/Peaking	Yes
Facility 717	Cary	NC	Solar	5.27	Intermediate/Peaking	Yes
Facility 718	Asheville	NC	Solar	5.43	Intermediate/Peaking	Yes
Facility 719	Wake Forest	NC	Solar	3.41	Intermediate/Peaking	Yes
Facility 720	Wilmington	NC	Solar	3.93	Intermediate/Peaking	Yes
Facility 721	Cary	NC	Solar	3.94	Intermediate/Peaking	Yes
Facility 722	Raleigh	NC	Solar	4.08	Intermediate/Peaking	Yes
Facility 723	Raleigh	NC	Solar	2.15	Intermediate/Peaking	Yes
Facility 724	Wilmington	NC	Solar	3.78	Intermediate/Peaking	Yes
Facility 725	Raleigh	NC	Solar	4.70	Intermediate/Peaking	Yes
Facility 726	West End	NC	Solar	3.28	Intermediate/Peaking	Yes
Facility 727	Benson	NC	Solar	6.35	Intermediate/Peaking	Yes
Facility 728	Kure Beach	NC	Solar	5.30	Intermediate/Peaking	Yes
Facility 729	Pinehurst	NC	Solar	4.28	Intermediate/Peaking	Yes
Facility 730	Siler City	NC	Solar	2.34	Intermediate/Peaking	Yes
Facility 731	Chapel Hill	NC	Solar	3.20	Intermediate/Peaking	Yes
Facility 732	Asheville	NC	Solar	3.32	Intermediate/Peaking	Yes
Facility 733	Willow Spring	NC	Solar	0.96	Intermediate/Peaking	Yes
Facility 734	Pittsboro	NC	Solar	2.48	Intermediate/Peaking	Yes
Facility 735	Willow Spring	NC	Solar	4.54	Intermediate/Peaking	Yes
Facility 736	Louisburg	NC	Solar	7.60	Intermediate/Peaking	Yes
Facility 737	Raleigh	NC	Solar	2.44	Intermediate/Peaking	Yes
Facility 738	Lillington	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 739	Asheville	NC	Solar	3.64	Intermediate/Peaking	Yes
Facility 740	Raleigh	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 741	Pittsboro	NC	Solar	7.06	Intermediate/Peaking	Yes
Facility 742	Fairview	NC	Solar	8.65	Intermediate/Peaking	Yes
Facility 743	Candler	NC	Solar	5.62	Intermediate/Peaking	Yes
Facility 744	Apex	NC	Solar	2.42	Intermediate/Peaking	Yes
Facility 745	Raleigh	NC	Solar	9.96	Intermediate/Peaking	Yes
Facility 746	Cary	NC	Solar	4.21	Intermediate/Peaking	Yes
Facility 747	Candler	NC	Solar	5.49	Intermediate/Peaking	Yes
Facility 748	Raleigh	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 749	Asheville	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 750	Asheville	NC	Solar	6.00	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 751	Aberdeen	NC	Solar	3.87	Intermediate/Peaking	Yes
Facility 752	Wilmington	NC	Solar	2.52	Intermediate/Peaking	Yes
Facility 753	Hampstead	NC	Solar	3.38	Intermediate/Peaking	Yes
Facility 754	Raleigh	NC	Solar	5.31	Intermediate/Peaking	Yes
Facility 755	Fairview	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 756	Whispering Pines	NC	Solar	3.74	Intermediate/Peaking	Yes
Facility 757	Pittsboro	NC	Solar	2.60	Intermediate/Peaking	Yes
Facility 758	Raleigh	NC	Solar	2.93	Intermediate/Peaking	Yes
Facility 759	Asheville	NC	Solar	3.80	Intermediate/Peaking	Yes
Facility 760	Asheville	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 761	Carolina Beach	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 762	Fletcher	NC	Solar	11.00	Intermediate/Peaking	Yes
Facility 763	Asheville	NC	Solar	3.64	Intermediate/Peaking	Yes
Facility 764	Swansboro	NC	Solar	2.45	Intermediate/Peaking	Yes
Facility 765	Pinehurst	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 766	Holly Springs	NC	Solar	1.80	Intermediate/Peaking	Yes
Facility 767	Asheville	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 768	Franklinton	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 769	Swannanoa, NC	NC	Solar	18.00	Intermediate/Peaking	Yes
Facility 770	Fuquay-Varina	NC	Solar	3.08	Intermediate/Peaking	Yes
Facility 771	Fletcher	NC	Solar	2.31	Intermediate/Peaking	Yes
Facility 772	Wilmington	NC	Solar	7.00	Intermediate/Peaking	Yes
Facility 773	Black Mountain	NC	Solar	4.70	Intermediate/Peaking	Yes
Facility 774	Raleigh	NC	Solar	3.24	Intermediate/Peaking	Yes
Facility 775	Wilmington	NC	Solar	2.63	Intermediate/Peaking	Yes
Facility 776	Cary	NC	Solar	3.88	Intermediate/Peaking	Yes
Facility 777	Asheville	NC	Solar	4.44	Intermediate/Peaking	Yes
Facility 778	Apex	NC	Solar	3.58	Intermediate/Peaking	Yes
Facility 779	Rougemont	NC	Solar	7.60	Intermediate/Peaking	Yes
Facility 780	Cary	NC	Solar	2.60	Intermediate/Peaking	Yes
Facility 781	Raleigh	NC	Solar	1.50	Intermediate/Peaking	Yes
Facility 782	Bear Creek	NC	Solar	7.34	Intermediate/Peaking	Yes
Facility 783	Hampstead	NC	Solar	3.03	Intermediate/Peaking	Yes
Facility 784	Kure Beach	NC	Solar	6.47	Intermediate/Peaking	Yes
Facility 785	Asheville, NC	NC	Solar	20.00	Intermediate/Peaking	Yes
Facility 786	Chapel Hill	NC	Solar	2.34	Intermediate/Peaking	Yes
Facility 787	Wilmington	NC	Solar	3.81	Intermediate/Peaking	Yes
Facility 788	Raleigh	NC	Solar	3.50	Intermediate/Peaking	Yes
Facility 789	Raleigh	NC	Solar	1.90	Intermediate/Peaking	Yes
Facility 790	Asheville	NC	Solar	5.16	Intermediate/Peaking	Yes
Facility 791	Cary	NC	Solar	2.94	Intermediate/Peaking	Yes
Facility 792	Sanford	NC	Solar	6.14	Intermediate/Peaking	Yes
Facility 793	Cary	NC	Solar	3.57	Intermediate/Peaking	Yes
Facility 794	Cary	NC	Solar	6.05	Intermediate/Peaking	Yes
Facility 795	Nashville	NC	Solar	4.50	Intermediate/Peaking	Yes
Facility 796	Holly Springs	NC	Solar	4.10	Intermediate/Peaking	Yes
Facility 797	Castle Hayne	NC	Solar	3.30	Intermediate/Peaking	Yes
Facility 798	Black Mountain	NC	Solar	4.73	Intermediate/Peaking	Yes
Facility 799	Selma	NC	Solar	4.72	Intermediate/Peaking	Yes
Facility 800	Raleigh	NC	Solar	3.60	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 801	Wilmington	NC	Solar	2.60	Intermediate/Peaking	Yes
Facility 802	Chapel Hill	NC	Solar	2.04	Intermediate/Peaking	Yes
Facility 803	Moncure	NC	Solar	3.56	Intermediate/Peaking	Yes
Facility 804	Asheville	NC	Solar	4.28	Intermediate/Peaking	Yes
Facility 805	Raleigh	NC	Solar	1.72	Intermediate/Peaking	Yes
Facility 806	Asheville	NC	Solar	7.10	Intermediate/Peaking	Yes
Facility 807	Raleigh	NC	Solar	3.44	Intermediate/Peaking	Yes
Facility 808	Franklinton	NC	Solar	2.30	Intermediate/Peaking	Yes
Facility 809	Raleigh	NC	Solar	4.45	Intermediate/Peaking	Yes
Facility 810	Cary	NC	Solar	4.20	Intermediate/Peaking	Yes
Facility 811	Cary	NC	Solar	4.46	Intermediate/Peaking	Yes
Facility 812	Cary	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 813	Chapel Hill	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 814	Cary	NC	Solar	4.58	Intermediate/Peaking	Yes
Facility 815	Asheville	NC	Solar	2.43	Intermediate/Peaking	Yes
Facility 816	Alexander	NC	Solar	3.87	Intermediate/Peaking	Yes
Facility 817	Raleigh	NC	Solar	3.50	Intermediate/Peaking	Yes
Facility 818	Fairview	NC	Solar	3.47	Intermediate/Peaking	Yes
Facility 819	Cameron	NC	Solar	3.43	Intermediate/Peaking	Yes
Facility 820	Wilmington	NC	Solar	4.18	Intermediate/Peaking	Yes
Facility 821	Asheville	NC	Solar	4.90	Intermediate/Peaking	Yes
Facility 822	Kenly	NC	Solar	3.80	Intermediate/Peaking	Yes
Facility 823	Arden	NC	Solar	3.72	Intermediate/Peaking	Yes
Facility 824	Cary	NC	Solar	3.51	Intermediate/Peaking	Yes
Facility 825	Weaverville	NC	Solar	3.05	Intermediate/Peaking	Yes
Facility 826	Hope Mills	NC	Solar	2.30	Intermediate/Peaking	Yes
Facility 827	Cary	NC	Solar	3.02	Intermediate/Peaking	Yes
Facility 828	Wilmington	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 829	Candler	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 830	Fuquay-Varina	NC	Solar	5.59	Intermediate/Peaking	Yes
Facility 831	Raleigh	NC	Solar	4.23	Intermediate/Peaking	Yes
Facility 832	Wilmington	NC	Solar	2.29	Intermediate/Peaking	Yes
Facility 833	Pittsboro	NC	Solar	2.19	Intermediate/Peaking	Yes
Facility 834	Wilmington	NC	Solar	6.37	Intermediate/Peaking	Yes
Facility 835	Benson	NC	Solar	3.76	Intermediate/Peaking	Yes
Facility 836	Cary	NC	Solar	7.90	Intermediate/Peaking	Yes
Facility 837	Wilmington	NC	Solar	2.04	Intermediate/Peaking	Yes
Facility 838	Pittsboro	NC	Solar	4.69	Intermediate/Peaking	Yes
Facility 839	Cary	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 840	Raleigh	NC	Solar	2.02	Intermediate/Peaking	Yes
Facility 841	Youngsville	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 842	Chapel Hill	NC	Solar	2.56	Intermediate/Peaking	Yes
Facility 843	Wilmington, NC	NC	Solar	100.00	Intermediate/Peaking	Yes
Facility 844	Southern Pines	NC	Solar	5.96	Intermediate/Peaking	Yes
Facility 845	Cary	NC	Solar	5.70	Intermediate/Peaking	Yes
Facility 846	Asheboro	NC	Solar	6.24	Intermediate/Peaking	Yes
Facility 847	Asheville	NC	Solar	4.16	Intermediate/Peaking	Yes
Facility 848	Apex	NC	Solar	5.78	Intermediate/Peaking	Yes
Facility 849	Apex	NC	Solar	3.40	Intermediate/Peaking	Yes
Facility 850	Southern Pines	NC	Solar	1.92	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 851	Asheville	NC	Solar	3.84	Intermediate/Peaking	Yes
Facility 852	Raleigh	NC	Solar	2.85	Intermediate/Peaking	Yes
Facility 853	Wilmington	NC	Solar	4.20	Intermediate/Peaking	Yes
Facility 854	Wilmington	NC	Solar	5.06	Intermediate/Peaking	Yes
Facility 855	Wilmington	NC	Solar	4.10	Intermediate/Peaking	Yes
Facility 856	Asheville	NC	Solar	7.60	Intermediate/Peaking	Yes
Facility 857	Pittsboro	NC	Solar	4.55	Intermediate/Peaking	Yes
Facility 858	Rocky Point	NC	Solar	2.30	Intermediate/Peaking	Yes
Facility 859	Holly Springs	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 860	Wilmington	NC	Solar	2.60	Intermediate/Peaking	Yes
Facility 861	Arden	NC	Solar	3.22	Intermediate/Peaking	Yes
Facility 862	Morrisville	NC	Solar	3.90	Intermediate/Peaking	Yes
Facility 863	Williston	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 864	Asheville	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 865	Raleigh	NC	Solar	6.75	Intermediate/Peaking	Yes
Facility 866	Wendell	NC	Solar	3.76	Intermediate/Peaking	Yes
Facility 867	Castle Hayne	NC	Solar	5.40	Intermediate/Peaking	Yes
Facility 868	Raleigh	NC	Solar	3.16	Intermediate/Peaking	Yes
Facility 869	Holly Springs	NC	Solar	4.22	Intermediate/Peaking	Yes
Facility 870	Apex	NC	Solar	3.46	Intermediate/Peaking	Yes
Facility 871	Wilmington	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 872	Wake Forest	NC	Solar	1.76	Intermediate/Peaking	Yes
Facility 873	Holly Springs	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 874	Asheville	NC	Solar	3.37	Intermediate/Peaking	Yes
Facility 875	Cameron	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 876	Asheville	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 877	Cary	NC	Solar	3.54	Intermediate/Peaking	Yes
Facility 878	Youngsville	NC	Solar	2.60	Intermediate/Peaking	Yes
Facility 879	Morrisville	NC	Solar	5.33	Intermediate/Peaking	Yes
Facility 880	Morehead City	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 881	Rougemont	NC	Solar	2.77	Intermediate/Peaking	Yes
Facility 882	Pinehurst	NC	Solar	3.08	Intermediate/Peaking	Yes
Facility 883	Raleigh, NC	NC	Solar	12.10	Intermediate/Peaking	Yes
Facility 884	Cary, NC	NC	Solar	32.00	Intermediate/Peaking	Yes
Facility 885	Wrightsville Beach, NC	NC	Solar	16.00	Intermediate/Peaking	Yes
Facility 886	Fairview	NC	Solar	3.10	Intermediate/Peaking	Yes
Facility 887	Benson	NC	Solar	2.58	Intermediate/Peaking	Yes
Facility 888	Barnardsville	NC	Solar	4.70	Intermediate/Peaking	Yes
Facility 889	Cary	NC	Solar	1.70	Intermediate/Peaking	Yes
Facility 890	Leicester	NC	Solar	2.06	Intermediate/Peaking	Yes
Facility 891	Leicester	NC	Solar	3.07	Intermediate/Peaking	Yes
Facility 892	Raleigh	NC	Solar	2.09	Intermediate/Peaking	Yes
Facility 893	Raleigh	NC	Solar	3.75	Intermediate/Peaking	Yes
Facility 894	Raleigh	NC	Solar	4.07	Intermediate/Peaking	Yes
Facility 895	Hampstead	NC	Solar	2.34	Intermediate/Peaking	Yes
Facility 896	Wilmington	NC	Solar	3.50	Intermediate/Peaking	Yes
Facility 897	Southern Pines	NC	Solar	1.80	Intermediate/Peaking	Yes
Facility 898	Leicester	NC	Solar	4.80	Intermediate/Peaking	Yes
Facility 899	Cary, NC	NC	Solar	16.00	Intermediate/Peaking	Yes
Facility 900	Wendell	NC	Solar	4.19	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 901	Raleigh	NC	Solar	2.09	Intermediate/Peaking	Yes
Facility 902	Wilmington	NC	Solar	1.00	Intermediate/Peaking	Yes
Facility 903	Raleigh	NC	Solar	3.49	Intermediate/Peaking	Yes
Facility 904	Black Mountain	NC	Solar	4.80	Intermediate/Peaking	Yes
Facility 905	West End	NC	Solar	5.58	Intermediate/Peaking	Yes
Facility 906	Garner	NC	Solar	3.04	Intermediate/Peaking	Yes
Facility 907	Asheville	NC	Solar	3.53	Intermediate/Peaking	Yes
Facility 908	Asheville	NC	Solar	3.76	Intermediate/Peaking	Yes
Facility 909	Asheville	NC	Solar	3.84	Intermediate/Peaking	Yes
Facility 910	Raleigh	NC	Solar	3.33	Intermediate/Peaking	Yes
Facility 911	Apex	NC	Solar	3.11	Intermediate/Peaking	Yes
Facility 912	Black Mountain	NC	Solar	9.60	Intermediate/Peaking	Yes
Facility 913	Black Mountain	NC	Solar	30.00	Intermediate/Peaking	Yes
Facility 914	Black Mountain	NC	Solar	6.24	Intermediate/Peaking	Yes
Facility 915	Leland	NC	Solar	3.77	Intermediate/Peaking	Yes
Facility 916	Holly Springs	NC	Solar	3.33	Intermediate/Peaking	Yes
Facility 917	Cary	NC	Solar	3.25	Intermediate/Peaking	Yes
Facility 918	Raleigh, NC	NC	Solar	515.00	Intermediate/Peaking	Yes
Facility 919	Wilmington	NC	Solar	3.70	Intermediate/Peaking	Yes
Facility 920	Cary	NC	Solar	5.60	Intermediate/Peaking	Yes
Facility 921	Cary	NC	Solar	2.48	Intermediate/Peaking	Yes
Facility 922	Pittsboro	NC	Solar	3.17	Intermediate/Peaking	Yes
Facility 923	Cary	NC	Solar	3.72	Intermediate/Peaking	Yes
Facility 924	Garner	NC	Solar	3.14	Intermediate/Peaking	Yes
Facility 925	Cary	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 926	Chapel Hill	NC	Solar	4.10	Intermediate/Peaking	Yes
Facility 927	Raleigh	NC	Solar	2.69	Intermediate/Peaking	Yes
Facility 928	Raleigh	NC	Solar	2.23	Intermediate/Peaking	Yes
Facility 929	Wilmington	NC	Solar	3.82	Intermediate/Peaking	Yes
Facility 930	Chapel Hill, NC	NC	Solar	48.00	Intermediate/Peaking	Yes
Facility 931	Garner	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 932	Cary	NC	Solar	1.50	Intermediate/Peaking	Yes
Facility 933	Pinehurst	NC	Solar	0.61	Intermediate/Peaking	Yes
Facility 934	Raleigh	NC	Solar	4.51	Intermediate/Peaking	Yes
Facility 935	Asheville	NC	Solar	3.20	Intermediate/Peaking	Yes
Facility 936	Weaverville	NC	Solar	6.28	Intermediate/Peaking	Yes
Facility 937	Rolesville	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 938	Chapel Hill	NC	Solar	3.50	Intermediate/Peaking	Yes
Facility 939	Cary	NC	Solar	3.96	Intermediate/Peaking	Yes
Facility 940	Raleigh	NC	Solar	2.12	Intermediate/Peaking	Yes
Facility 941	Youngsville	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 942	Pinehurst	NC	Solar	1.00	Intermediate/Peaking	Yes
Facility 943	Wilmington, NC	NC	Solar	40.00	Intermediate/Peaking	Yes
Facility 944	Hampstead	NC	Solar	2.68	Intermediate/Peaking	Yes
Facility 945	Pittsboro	NC	Solar	4.15	Intermediate/Peaking	Yes
Facility 946	Wilmington	NC	Solar	8.21	Intermediate/Peaking	Yes
Facility 947	Wilmington	NC	Solar	4.80	Intermediate/Peaking	Yes
Facility 948	Cameron	NC	Solar	4.94	Intermediate/Peaking	Yes
Facility 949	Knightdale	NC	Solar	0.50	Intermediate/Peaking	Yes
Facility 950	Clayton	NC	Solar	3.78	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 951	Asheville	NC	Solar	2.76	Intermediate/Peaking	Yes
Facility 952	OXFORD	NC	Solar	4.15	Intermediate/Peaking	Yes
Facility 953	New Hill	NC	Solar	5.09	Intermediate/Peaking	Yes
Facility 954	Wilmington	NC	Solar	3.43	Intermediate/Peaking	Yes
Facility 955	OXFORD	NC	Solar	4.56	Intermediate/Peaking	Yes
Facility 956	Pittsboro	NC	Solar	3.69	Intermediate/Peaking	Yes
Facility 957	Willow Spring	NC	Solar	3.97	Intermediate/Peaking	Yes
Facility 958	Clayton	NC	Solar	5.20	Intermediate/Peaking	Yes
Facility 959	Wilmington	NC	Solar	2.43	Intermediate/Peaking	Yes
Facility 960	Willow Spring	NC	Solar	2.60	Intermediate/Peaking	Yes
Facility 961	Barnardsville	NC	Solar	2.60	Intermediate/Peaking	Yes
Facility 962	Raleigh	NC	Solar	4.24	Intermediate/Peaking	Yes
Facility 963	Pittsboro	NC	Solar	1.63	Intermediate/Peaking	Yes
Facility 964	Raleigh	NC	Solar	1.75	Intermediate/Peaking	Yes
Facility 965	Pittsboro	NC	Solar	1.63	Intermediate/Peaking	Yes
Facility 966	Garner	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 967	Goldsboro	NC	Solar	9.46	Intermediate/Peaking	Yes
Facility 968	Spring Hope, NC	NC	Solar	13.00	Intermediate/Peaking	Yes
Facility 969	Raleigh	NC	Solar	3.19	Intermediate/Peaking	Yes
Facility 970	Garner	NC	Solar	4.92	Intermediate/Peaking	Yes
Facility 971	Apex	NC	Solar	4.10	Intermediate/Peaking	Yes
Facility 972	West End	NC	Solar	4.20	Intermediate/Peaking	Yes
Facility 973	Princeton	NC	Solar	3.99	Intermediate/Peaking	Yes
Facility 974	Wilmington	NC	Solar	4.25	Intermediate/Peaking	Yes
Facility 975	Vass	NC	Solar	3.66	Intermediate/Peaking	Yes
Facility 976	New Hill	NC	Solar	5.47	Intermediate/Peaking	Yes
Facility 977	Chapel Hill	NC	Solar	3.98	Intermediate/Peaking	Yes
Facility 978	Cary	NC	Solar	3.05	Intermediate/Peaking	Yes
Facility 979	Raleigh	NC	Solar	2.07	Intermediate/Peaking	Yes
Facility 980	Wilmington	NC	Solar	3.72	Intermediate/Peaking	Yes
Facility 981	Arden	NC	Solar	4.47	Intermediate/Peaking	Yes
Facility 982	Fuquay Varina	NC	Solar	5.30	Intermediate/Peaking	Yes
Facility 983	Cary	NC	Solar	6.78	Intermediate/Peaking	Yes
Facility 984	Fletcher	NC	Solar	7.00	Intermediate/Peaking	Yes
Facility 985	Wilmington	NC	Solar	5.53	Intermediate/Peaking	Yes
Facility 986	Wake Forest	NC	Solar	2.79	Intermediate/Peaking	Yes
Facility 987	Cary	NC	Solar	3.85	Intermediate/Peaking	Yes
Facility 988	Morehead City	NC	Solar	3.25	Intermediate/Peaking	Yes
Facility 989	Garner	NC	Solar	38.40	Intermediate/Peaking	Yes
Facility 990	Raleigh	NC	Solar	400.00	Intermediate/Peaking	Yes
Facility 991	Weaverville	NC	Solar	4.50	Intermediate/Peaking	Yes
Facility 992	Holly Springs	NC	Solar	400.00	Intermediate/Peaking	Yes
Facility 993	Raleigh	NC	Solar	3.10	Intermediate/Peaking	Yes
Facility 994	Morrisville	NC	Solar	150.00	Intermediate/Peaking	Yes
Facility 995	Raleigh	NC	Solar	1.63	Intermediate/Peaking	Yes
Facility 996	Sanford	NC	Solar	25.00	Intermediate/Peaking	Yes
Facility 997	Raleigh	NC	Solar	3.10	Intermediate/Peaking	Yes
Facility 998	Wilmington	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 999	Goldsboro	NC	Solar	4,975.00	Intermediate/Peaking	Yes
Facility 1000	Raleigh	NC	Solar	7.47	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 1001	Chapel Hill	NC	Solar	4.16	Intermediate/Peaking	Yes
Facility 1002	Asheville	NC	Solar	3.86	Intermediate/Peaking	Yes
Facility 1003	Pittsboro	NC	Solar	3.70	Intermediate/Peaking	Yes
Facility 1004	Star	NC	Solar	2.30	Intermediate/Peaking	Yes
Facility 1005	Harnett	NC	Solar	4,400.00	Intermediate/Peaking	Yes
Facility 1006	Arden	NC	Solar	23.00	Intermediate/Peaking	Yes
Facility 1007	Asheboro	NC	Solar	398.00	Intermediate/Peaking	Yes
Facility 1008	Cary	NC	Solar	190.00	Intermediate/Peaking	Yes
Facility 1009	Warrenton	NC	Solar	383.00	Intermediate/Peaking	Yes
Facility 1010	Laurinburg	NC	Solar	193.00	Intermediate/Peaking	Yes
Facility 1011	Chapel Hill	NC	Solar	2.08	Intermediate/Peaking	Yes
Facility 1012	Fairview	NC	Solar	34.00	Intermediate/Peaking	Yes
Facility 1013	Cameron	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 1014	Asheville	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 1015	Bailey	NC	Solar	4,950.00	Intermediate/Peaking	Yes
Facility 1016	Chapel Hill	NC	Solar	6.93	Intermediate/Peaking	Yes
Facility 1017	Asheville	NC	Solar	60.00	Intermediate/Peaking	Yes
Facility 1018	Apex	NC	Solar	20.00	Intermediate/Peaking	Yes
Facility 1019	Clayton	NC	Solar	17.00	Intermediate/Peaking	Yes
Facility 1020	Weaverville	NC	Solar	3.01	Intermediate/Peaking	Yes
Facility 1021	Beulaville	NC	Solar	1,990.00	Intermediate/Peaking	Yes
Facility 1022	Fuquay-Varina	NC	Solar	2.10	Intermediate/Peaking	Yes
Facility 1023	Clayton	NC	Solar	407.00	Intermediate/Peaking	Yes
Facility 1024	Weaverville	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 1025	Asheville	NC	Solar	1,200.00	Intermediate/Peaking	Yes
Facility 1026	Asheville	NC	Solar	3.90	Intermediate/Peaking	Yes
Facility 1027	Asheville	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 1028	Asheville	NC	Solar	3.90	Intermediate/Peaking	Yes
Facility 1029	Asheville	NC	Solar	1.40	Intermediate/Peaking	Yes
Facility 1030	Bladenboro	NC	Solar	4,975.00	Intermediate/Peaking	Yes
Facility 1031	Apex	NC	Solar	3.90	Intermediate/Peaking	Yes
Facility 1032	Warrenton	NC	Solar	4,975.00	Intermediate/Peaking	Yes
Facility 1033	Alexander	NC	Solar	2.91	Intermediate/Peaking	Yes
Facility 1034	Asheville	NC	Solar	3.02	Intermediate/Peaking	Yes
Facility 1035	OXFORD	NC	Solar	2.83	Intermediate/Peaking	Yes
Facility 1036	Fremont	NC	Solar	4.62	Intermediate/Peaking	Yes
Facility 1037	Fuquay-Varina	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 1038	Asheville	NC	Solar	4.62	Intermediate/Peaking	Yes
Facility 1039	Cary	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 1040	Balsam	NC	Solar	3.80	Intermediate/Peaking	Yes
Facility 1041	Raleigh	NC	Solar	5.70	Intermediate/Peaking	Yes
Facility 1042	Black Mountain	NC	Solar	6.10	Intermediate/Peaking	Yes
Facility 1043	Wilmington	NC	Solar	1.40	Intermediate/Peaking	Yes
Facility 1044	Person County	NC	Solar	520.00	Intermediate/Peaking	Yes
Facility 1045	Raleigh	NC	Solar	40.00	Intermediate/Peaking	Yes
Facility 1046	Raleigh	NC	Solar	200.00	Intermediate/Peaking	Yes
Facility 1047	Asheville	NC	Solar	193.00	Intermediate/Peaking	Yes
Facility 1048	Morehead City	NC	Solar	1.20	Intermediate/Peaking	Yes
Facility 1049	Garner	NC	Solar	2,500.00	Intermediate/Peaking	Yes
Facility 1050	Garner	NC	Solar	1,050.00	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 1051	Chapel Hill	NC	Solar	3.10	Intermediate/Peaking	Yes
Facility 1052	Whiteville	NC	Solar	4,980.00	Intermediate/Peaking	Yes
Facility 1053	Cameron	NC	Solar	8.45	Intermediate/Peaking	Yes
Facility 1054	Pittsboro	NC	Solar	2.64	Intermediate/Peaking	Yes
Facility 1055	Asheville	NC	Solar	4.70	Intermediate/Peaking	Yes
Facility 1056	Wilmington	NC	Solar	9.90	Intermediate/Peaking	Yes
Facility 1057	Apex	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 1058	Waynesville	NC	Solar	2.65	Intermediate/Peaking	Yes
Facility 1059	Raleigh	NC	Solar	23.00	Intermediate/Peaking	Yes
Facility 1060	Pittsboro	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 1061	Zebulon	NC	Solar	257.00	Intermediate/Peaking	Yes
Facility 1062	Arden	NC	Solar	160.00	Intermediate/Peaking	Yes
Facility 1063	Pittsboro	NC	Solar	2.77	Intermediate/Peaking	Yes
Facility 1064	Chapel Hill	NC	Solar	1.60	Intermediate/Peaking	Yes
Facility 1065	Arden	NC	Solar	3.90	Intermediate/Peaking	Yes
Facility 1066	Cary	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 1067	Pittsboro	NC	Solar	1.80	Intermediate/Peaking	Yes
Facility 1068	Cary	NC	Solar	3.85	Intermediate/Peaking	Yes
Facility 1069	Nashville	NC	Solar	4.50	Intermediate/Peaking	Yes
Facility 1070	Chapel Hill	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 1071	Raleigh	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 1072	Pittsboro	NC	Solar	5.20	Intermediate/Peaking	Yes
Facility 1073	Holly Springs	NC	Solar	3.20	Intermediate/Peaking	Yes
Facility 1074	Asheville	NC	Solar	44.00	Intermediate/Peaking	Yes
Facility 1075	Henderson	NC	Solar	4,975.00	Intermediate/Peaking	Yes
Facility 1076	Raleigh	NC	Solar	3.16	Intermediate/Peaking	Yes
Facility 1077	Asheville	NC	Solar	4.74	Intermediate/Peaking	Yes
Facility 1078	Cary	NC	Solar	7.28	Intermediate/Peaking	Yes
Facility 1079	Weaverville	NC	Solar	2.10	Intermediate/Peaking	Yes
Facility 1080	Morehead City	NC	Solar	3.90	Intermediate/Peaking	Yes
Facility 1081	Nashville	NC	Solar	3.40	Intermediate/Peaking	Yes
Facility 1082	Asheville	NC	Solar	4.55	Intermediate/Peaking	Yes
Facility 1083	Wilmington	NC	Solar	6.02	Intermediate/Peaking	Yes
Facility 1084	Chapel Hill	NC	Solar	6.30	Intermediate/Peaking	Yes
Facility 1085	Raleigh	NC	Solar	2.94	Intermediate/Peaking	Yes
Facility 1086	Apex	NC	Solar	3.70	Intermediate/Peaking	Yes
Facility 1087	Raleigh	NC	Solar	16.00	Intermediate/Peaking	Yes
Facility 1088	Dunn	NC	Solar	1,990.00	Intermediate/Peaking	Yes
Facility 1089	Warsaw	NC	Solar	5,000.00	Intermediate/Peaking	Yes
Facility 1090	Raleigh	NC	Solar	2.70	Intermediate/Peaking	Yes
Facility 1091	Goldsboro	NC	Solar	1,900.00	Intermediate/Peaking	Yes
Facility 1092	Cary	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 1093	Vass	NC	Solar	7.40	Intermediate/Peaking	Yes
Facility 1094	Raleigh	NC	Solar	3.63	Intermediate/Peaking	Yes
Facility 1095	Pittsboro	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 1096	Raleigh	NC	Solar	2.90	Intermediate/Peaking	Yes
Facility 1097	Pittsboro	NC	Solar	6.40	Intermediate/Peaking	Yes
Facility 1098	Fairview	NC	Solar	7.76	Intermediate/Peaking	Yes
Facility 1099	Burnsville	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 1100	Fuquay-Varina	NC	Solar	8.50	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 1101	Fletcher	NC	Solar	410.00	Intermediate/Peaking	Yes
Facility 1102	New Bern	NC	Solar	977.90	Intermediate/Peaking	Yes
Facility 1103	Weaverville	NC	Solar	3.84	Intermediate/Peaking	Yes
Facility 1104	Raleigh	NC	Solar	400.00	Intermediate/Peaking	Yes
Facility 1105	Garner	NC	Solar	24.00	Intermediate/Peaking	Yes
Facility 1106	Chapel Hill	NC	Solar	1,000.00	Intermediate/Peaking	Yes
Facility 1107	Asheville	NC	Solar	9.66	Intermediate/Peaking	Yes
Facility 1108	Raleigh	NC	Solar	565.00	Intermediate/Peaking	Yes
Facility 1109	Raleigh	NC	Solar	1,140.00	Intermediate/Peaking	Yes
Facility 1110	Weaverville	NC	Solar	19.00	Intermediate/Peaking	Yes
Facility 1111	Canton	NC	Solar	440.00	Intermediate/Peaking	Yes
Facility 1112	Cary	NC	Solar	1,500.00	Intermediate/Peaking	Yes
Facility 1113	Clyde	NC	Solar	80.00	Intermediate/Peaking	Yes
Facility 1114	Asheville	NC	Solar	66.00	Intermediate/Peaking	Yes
Facility 1115	Fairmont	NC	Solar	4,000.00	Intermediate/Peaking	Yes
Facility 1116	Pittsboro	NC	Solar	200.00	Intermediate/Peaking	Yes
Facility 1117	Pittsboro	NC	Solar	81.00	Intermediate/Peaking	Yes
Facility 1118	Louisburg	NC	Solar	1,900.00	Intermediate/Peaking	Yes
Facility 1119	Louisburg	NC	Solar	1,990.00	Intermediate/Peaking	Yes
Facility 1120	Willow Spring	NC	Solar	4,980.00	Intermediate/Peaking	Yes
Facility 1121	Chadbourn	NC	Solar	3,800.00	Intermediate/Peaking	Yes
Facility 1122	Willow Springs	NC	Solar	2.05	Intermediate/Peaking	Yes
Facility 1123	Chapel Hill	NC	Solar	2.36	Intermediate/Peaking	Yes
Facility 1124	Asheville	NC	Solar	2.70	Intermediate/Peaking	Yes
Facility 1125	Pittsboro	NC	Solar	1.80	Intermediate/Peaking	Yes
Facility 1126	Cary	NC	Solar	3.40	Intermediate/Peaking	Yes
Facility 1127	Chapel Hill	NC	Solar	3.08	Intermediate/Peaking	Yes
Facility 1128	Norlina	NC	Solar	384.00	Intermediate/Peaking	Yes
Facility 1129	Wendell	NC	Solar	2.83	Intermediate/Peaking	Yes
Facility 1130	Oriental	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 1131	Pittsboro	NC	Solar	3.02	Intermediate/Peaking	Yes
Facility 1132	Barnardsville	NC	Solar	2.70	Intermediate/Peaking	Yes
Facility 1133	Oxford	NC	Solar	2,750.00	Intermediate/Peaking	Yes
Facility 1134	Fairview	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 1135	Kinston	NC	Solar	193.00	Intermediate/Peaking	Yes
Facility 1136	Fletcher	NC	Solar	2.52	Intermediate/Peaking	Yes
Facility 1137	Garner	NC	Solar	160.00	Intermediate/Peaking	Yes
Facility 1138	Raleigh	NC	Solar	2.53	Intermediate/Peaking	Yes
Facility 1139	Asheville	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 1140	Black Mountain	NC	Solar	3.97	Intermediate/Peaking	Yes
Facility 1141	Henderson	NC	Solar	100.00	Intermediate/Peaking	Yes
Facility 1142	Henderson	NC	Solar	125.00	Intermediate/Peaking	Yes
Facility 1143	Spruce Pine	NC	Solar	3.80	Intermediate/Peaking	Yes
Facility 1144	Siler City	NC	Solar	4.10	Intermediate/Peaking	Yes
Facility 1145	Spruce Pine	NC	Solar	4.60	Intermediate/Peaking	Yes
Facility 1146	Apex	NC	Solar	6.44	Intermediate/Peaking	Yes
Facility 1147	Oxford	NC	Solar	158.00	Intermediate/Peaking	Yes
Facility 1148	Roxboro	NC	Solar	1.85	Intermediate/Peaking	Yes
Facility 1149	Dudley	NC	Solar	22.00	Intermediate/Peaking	Yes
Facility 1150	Sanford	NC	Solar	8.50	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 1151	Fairview	NC	Solar	3.84	Intermediate/Peaking	Yes
Facility 1152	Clayton	NC	Solar	2.70	Intermediate/Peaking	Yes
Facility 1153	Holly Springs	NC	Solar	4.20	Intermediate/Peaking	Yes
Facility 1154	Fairview	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 1155	Goldsboro	NC	Solar	4.47	Intermediate/Peaking	Yes
Facility 1156	Clayton	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 1157	Asheville	NC	Solar	4.42	Intermediate/Peaking	Yes
Facility 1158	Raleigh	NC	Solar	3.26	Intermediate/Peaking	Yes
Facility 1159	Asheville	NC	Solar	3.80	Intermediate/Peaking	Yes
Facility 1160	Wilmington	NC	Solar	3.10	Intermediate/Peaking	Yes
Facility 1161	Raleigh	NC	Solar	2.90	Intermediate/Peaking	Yes
Facility 1162	Raleigh	NC	Solar	1.54	Intermediate/Peaking	Yes
Facility 1163	Swannanoa	NC	Solar	3.80	Intermediate/Peaking	Yes
Facility 1164	Fuquay-Varina	NC	Solar	4.40	Intermediate/Peaking	Yes
Facility 1165	Pittsboro	NC	Solar	3.62	Intermediate/Peaking	Yes
Facility 1166	Alexander	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 1167	Henderson	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 1168	Asheville	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 1169	Asheville	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 1170	Barnardsville	NC	Solar	3.64	Intermediate/Peaking	Yes
Facility 1171	Fair View	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 1172	Asheville	NC	Solar	4.30	Intermediate/Peaking	Yes
Facility 1173	Zebulon	NC	Solar	9.90	Intermediate/Peaking	Yes
Facility 1174	Pinehurst	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 1175	Raleigh	NC	Solar	5.31	Intermediate/Peaking	Yes
Facility 1176	Siler City	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 1177	Raleigh	NC	Solar	3.72	Intermediate/Peaking	Yes
Facility 1178	Holly Springs	NC	Solar	4.20	Intermediate/Peaking	Yes
Facility 1179	Henderson	NC	Solar	4.70	Intermediate/Peaking	Yes
Facility 1180	Goldsboro	NC	Solar	4.06	Intermediate/Peaking	Yes
Facility 1181	Raleigh	NC	Solar	1,000.00	Intermediate/Peaking	Yes
Facility 1182	Carthage	NC	Solar	8.00	Intermediate/Peaking	Yes
Facility 1183	Aberdeen	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 1184	Waynesville	NC	Solar	23.00	Intermediate/Peaking	Yes
Facility 1185	Asheville	NC	Solar	23.00	Intermediate/Peaking	Yes
Facility 1186	Leicester	NC	Solar	6.00	Intermediate/Peaking	Yes
Facility 1187	Arden	NC	Solar	3.00	Intermediate/Peaking	Yes
Facility 1188	Cary	NC	Solar	2.30	Intermediate/Peaking	Yes
Facility 1189	Weaverville	NC	Solar	3.70	Intermediate/Peaking	Yes
Facility 1190	Siler City	NC	Solar	7.10	Intermediate/Peaking	Yes
Facility 1191	Warsaw	NC	Solar	1,990.00	Intermediate/Peaking	Yes
Facility 1192	Pinehurst	NC	Solar	8.40	Intermediate/Peaking	Yes
Facility 1193	Apex	NC	Solar	5.47	Intermediate/Peaking	Yes
Facility 1194	Hookerton	NC	Solar	1,990.00	Intermediate/Peaking	Yes
Facility 1195	Morrisville	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 1196	Raleigh	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 1197	Cary	NC	Solar	2.52	Intermediate/Peaking	Yes
Facility 1198	Cary	NC	Solar	6.58	Intermediate/Peaking	Yes
Facility 1199	Black Mountain	NC	Solar	2.90	Intermediate/Peaking	Yes
Facility 1200	Rougemont	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 1201	Asheville	NC	Solar	3.30	Intermediate/Peaking	Yes
Facility 1202	Kinston	NC	Solar	4,980.00	Intermediate/Peaking	Yes
Facility 1203	Kinston	NC	Solar	4,980.00	Intermediate/Peaking	Yes
Facility 1204	Pinehurst	NC	Solar	2.83	Intermediate/Peaking	Yes
Facility 1205	Asheville	NC	Solar	2.30	Intermediate/Peaking	Yes
Facility 1206	Cary	NC	Solar	2.40	Intermediate/Peaking	Yes
Facility 1207	Cary	NC	Solar	2.52	Intermediate/Peaking	Yes
Facility 1208	Chocowinity	NC	Solar	6.10	Intermediate/Peaking	Yes
Facility 1209	Weaverville	NC	Solar	3.24	Intermediate/Peaking	Yes
Facility 1210	Pittsboro	NC	Solar	2.80	Intermediate/Peaking	Yes
Facility 1211	Sanford	NC	Solar	5.00	Intermediate/Peaking	Yes
Facility 1212	Asheville	NC	Solar	21.00	Intermediate/Peaking	Yes
Facility 1213	Asheville	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 1214	Pittsboro	NC	Solar	4.86	Intermediate/Peaking	Yes
Facility 1215	Cary	NC	Solar	9.00	Intermediate/Peaking	Yes
Facility 1216	Asheville	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 1217	Robbins	NC	Solar	2.82	Intermediate/Peaking	Yes
Facility 1218	Asheville	NC	Solar	5.30	Intermediate/Peaking	Yes
Facility 1219	Pittsboro	NC	Solar	7.62	Intermediate/Peaking	Yes
Facility 1220	Raleigh	NC	Solar	1.64	Intermediate/Peaking	Yes
Facility 1221	Raleigh	NC	Solar	2.10	Intermediate/Peaking	Yes
Facility 1222	Asheville	NC	Solar	3.79	Intermediate/Peaking	Yes
Facility 1223	Asheville	NC	Solar	2.54	Intermediate/Peaking	Yes
Facility 1224	Raleigh	NC	Solar	12.00	Intermediate/Peaking	Yes
Facility 1225	Henderson	NC	Solar	3,000.00	Intermediate/Peaking	Yes
Facility 1226	Raleigh	NC	Solar	3.08	Intermediate/Peaking	Yes
Facility 1227	Wilmington	NC	Solar	1.38	Intermediate/Peaking	Yes
Facility 1228	Rowland	NC	Solar	4,975.00	Intermediate/Peaking	Yes
Facility 1229	Columbus	NC	Solar	4,950.00	Intermediate/Peaking	Yes
Facility 1230	Pittsboro	NC	Solar	1.84	Intermediate/Peaking	Yes
Facility 1231	Chapel Hill	NC	Solar	2.06	Intermediate/Peaking	Yes
Facility 1232	Middlesex	NC	Solar	2.17	Intermediate/Peaking	Yes
Facility 1233	Apex	NC	Solar	1.60	Intermediate/Peaking	Yes
Facility 1234	Asheville	NC	Solar	3.20	Intermediate/Peaking	Yes
Facility 1235	Pittsboro	NC	Solar	1.92	Intermediate/Peaking	Yes
Facility 1236	Pittsboro	NC	Solar	2.60	Intermediate/Peaking	Yes
Facility 1237	Raleigh	NC	Solar	3.35	Intermediate/Peaking	Yes
Facility 1238	Moncure	NC	Solar	4,980.00	Intermediate/Peaking	Yes
Facility 1239	La Grange	NC	Solar	4,980.00	Intermediate/Peaking	Yes
Facility 1240	Raleigh	NC	Solar	4.90	Intermediate/Peaking	Yes
Facility 1241	Mount Olive	NC	Solar	4,975.00	Intermediate/Peaking	Yes
Facility 1242	Liberty	NC	Solar	3.30	Intermediate/Peaking	Yes
Facility 1243	Black Mountain	NC	Solar	1.90	Intermediate/Peaking	Yes
Facility 1244	Nashville	NC	Solar	4,950.00	Intermediate/Peaking	Yes
Facility 1245	Siler City	NC	Solar	2.65	Intermediate/Peaking	Yes
Facility 1246	Vass	NC	Solar	13.00	Intermediate/Peaking	Yes
Facility 1247	Raleigh	NC	Solar	4.80	Intermediate/Peaking	Yes
Facility 1248	Raleigh	NC	Solar	5.40	Intermediate/Peaking	Yes
Facility 1249	Pittsboro	NC	Solar	1.80	Intermediate/Peaking	Yes
Facility 1250	Raleigh, NC	NC	Solar	1,040.00	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 1251	Laurinburg	NC	Solar	2,000.00	Intermediate/Peaking	Yes
Facility 1252	Laurinburg	NC	Solar	2,000.00	Intermediate/Peaking	Yes
Facility 1253	Gibson	NC	Solar	5,000.00	Intermediate/Peaking	Yes
Facility 1254	Red Springs	NC	Solar	4,950.00	Intermediate/Peaking	Yes
Facility 1255	Pinehurst	NC	Solar	3.80	Intermediate/Peaking	Yes
Facility 1256	Louisburg	NC	Solar	48.00	Intermediate/Peaking	Yes
Facility 1257	Pittsboro	NC	Solar	1.85	Intermediate/Peaking	Yes
Facility 1258	Wendell	NC	Solar	2.98	Intermediate/Peaking	Yes
Facility 1259	Asheville	NC	Solar	1.40	Intermediate/Peaking	Yes
Facility 1260	Person County	NC	Solar	1,000.00	Intermediate/Peaking	Yes
Facility 1261	Person County	NC	Solar	2,400.00	Intermediate/Peaking	Yes
Facility 1262	Asheville	NC	Solar	1.68	Intermediate/Peaking	Yes
Facility 1263	Morrisville	NC	Solar	6.38	Intermediate/Peaking	Yes
Facility 1264	Pittsboro	NC	Solar	2.48	Intermediate/Peaking	Yes
Facility 1265	Bunn	NC	Solar	3,600.00	Intermediate/Peaking	Yes
Facility 1266	Fairmont	NC	Solar	3,600.00	Intermediate/Peaking	Yes
Facility 1267	Maxton	NC	Solar	3,600.00	Intermediate/Peaking	Yes
Facility 1268	Wilmington	NC	Solar	383.00	Intermediate/Peaking	Yes
Facility 1269	Raeford	NC	Solar	4,980.00	Intermediate/Peaking	Yes
Facility 1270	St. Pauls	NC	Solar	4,980.00	Intermediate/Peaking	Yes
Facility 1271	Raleigh	NC	Solar	2.83	Intermediate/Peaking	Yes
Facility 1272	Wilmington	NC	Solar	3.90	Intermediate/Peaking	Yes
Facility 1273	Raleigh	NC	Solar	1.60	Intermediate/Peaking	Yes
Facility 1274	Fuquay-Varina	NC	Solar	410.00	Intermediate/Peaking	Yes
Facility 1275	Cary	NC	Solar	3.74	Intermediate/Peaking	Yes
Facility 1276	Cary	NC	Solar	193.00	Intermediate/Peaking	Yes
Facility 1277	Wendell	NC	Solar	1.90	Intermediate/Peaking	Yes
Facility 1278	Barnardsville	NC	Solar	4.92	Intermediate/Peaking	Yes
Facility 1279	Benson	NC	Solar	4.60	Intermediate/Peaking	Yes
Facility 1280	Raleigh	NC	Solar	4.14	Intermediate/Peaking	Yes
Facility 1281	Kure Beach	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 1282	Wilmington	NC	Solar	1.20	Intermediate/Peaking	Yes
Facility 1283	Semora	NC	Solar	4.20	Intermediate/Peaking	Yes
Facility 1284	Wilmington	NC	Solar	9.90	Intermediate/Peaking	Yes
Facility 1285	Hookerton	NC	Solar	5.06	Intermediate/Peaking	Yes
Facility 1286	Rockingham	NC	Solar	4,980.00	Intermediate/Peaking	Yes
Facility 1287	Wilmington	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 1288	Candler	NC	Solar	2.36	Intermediate/Peaking	Yes
Facility 1289	Wilmington	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 1290	Rose Hill	NC	Solar	1,900.00	Intermediate/Peaking	Yes
Facility 1291	Roxboro, NC	NC	Solar	4,980.00	Intermediate/Peaking	Yes
Facility 1292	Weaverville	NC	Solar	3.84	Intermediate/Peaking	Yes
Facility 1293	Vass	NC	Solar	3.60	Intermediate/Peaking	Yes
Facility 1294	Raleigh	NC	Solar	7.50	Intermediate/Peaking	Yes
Facility 1295	Nash County	NC	Solar	1,200.00	Intermediate/Peaking	Yes
Facility 1296	Cary	NC	Solar	960.00	Intermediate/Peaking	Yes
Facility 1297	Cary	NC	Solar	800.00	Intermediate/Peaking	Yes
Facility 1298	Laurinburg	NC	Solar	4.95	Intermediate/Peaking	Yes
Facility 1299	Pittsboro	NC	Solar	1.72	Intermediate/Peaking	Yes
Facility 1300	Raleigh	NC	Solar	3.62	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 1301	Spring Lake	NC	Solar	3.90	Intermediate/Peaking	Yes
Facility 1302	Raleigh	NC	Solar	2.60	Intermediate/Peaking	Yes
Facility 1303	Shannon	NC	Solar	4,980.00	Intermediate/Peaking	Yes
Facility 1304	Raleigh	NC	Solar	2.00	Intermediate/Peaking	Yes
Facility 1305	Laurinburg	NC	Solar	10.00	Intermediate/Peaking	Yes
Facility 1306	Laurinburg	NC	Solar	11.00	Intermediate/Peaking	Yes
Facility 1307	Mount Olive	NC	Solar	1,980.00	Intermediate/Peaking	Yes
Facility 1308	Raleigh	NC	Solar	385.00	Intermediate/Peaking	Yes
Facility 1309	Wilmington	NC	Solar	1,600.00	Intermediate/Peaking	Yes
Facility 1310	Rowland	NC	Solar	4,980.00	Intermediate/Peaking	Yes
Facility 1311	Fletcher	NC	Solar	1,000.00	Intermediate/Peaking	Yes
Facility 1312	Chocowinity	NC	Solar	3.90	Intermediate/Peaking	Yes
Facility 1313	Raleigh	NC	Solar	5.50	Intermediate/Peaking	Yes
Facility 1314	Durham	NC	Solar	3.40	Intermediate/Peaking	Yes
Facility 1315	Weaverville	NC	Solar	3.25	Intermediate/Peaking	Yes
Facility 1316	Cary	NC	Solar	3.79	Intermediate/Peaking	Yes
Facility 1317	Clayton	NC	Solar	4.74	Intermediate/Peaking	Yes
Facility 1318	Cary	NC	Solar	8.70	Intermediate/Peaking	Yes
Facility 1319	Weaverville	NC	Solar	7.30	Intermediate/Peaking	Yes
Facility 1320	Wilmington	NC	Solar	1,000.00	Intermediate/Peaking	Yes
Facility 1321	Weaverville	NC	Solar	193.00	Intermediate/Peaking	Yes
Facility 1322	Black Mountain	NC	Solar	40.00	Intermediate/Peaking	Yes
Facility 1323	Cary	NC	Solar	2.91	Intermediate/Peaking	Yes
Facility 1324	Asheville	NC	Solar	4.32	Intermediate/Peaking	Yes
Facility 1325	Southern Pines	NC	Solar	20.00	Intermediate/Peaking	Yes
Facility 1326	Pinehurst	NC	Solar	3.56	Intermediate/Peaking	Yes
Facility 1327	Asheville	NC	Solar	3.90	Intermediate/Peaking	Yes
Facility 1328	Asheville	NC	Solar	8.00	Intermediate/Peaking	Yes
Facility 1329	Wilmington	NC	Solar	7.68	Intermediate/Peaking	Yes
Facility 1330	Asheboro	NC	Solar	340.00	Intermediate/Peaking	Yes
Facility 1331	Aberdeen	NC	Solar	4.14	Intermediate/Peaking	Yes
Facility 1332	Asheville	NC	Solar	2.60	Intermediate/Peaking	Yes
Facility 1333	Raleigh	NC	Solar	4.00	Intermediate/Peaking	Yes
Facility 1334	Pittsboro	NC	Solar	2.50	Intermediate/Peaking	Yes
Facility 1335	Asheville	NC	Solar	1.65	Intermediate/Peaking	Yes
Facility 1336	Henderson	NC	Solar	6.84	Intermediate/Peaking	Yes
Facility 1337	Asheville	NC	Solar	1.50	Intermediate/Peaking	Yes
Facility 1338	Raleigh	NC	Solar	9.60	Intermediate/Peaking	Yes
Facility 1339	Henderson	NC	Solar	17.50	Intermediate/Peaking	Yes
Facility 1340	Raleigh	NC	Solar	6.50	Intermediate/Peaking	Yes
Facility 1341	Black Mountain	NC	Solar	1.44	Intermediate/Peaking	Yes
Facility 1342	Asheville	NC	Solar	2.60	Intermediate/Peaking	Yes
Facility 1343	Roxboro	NC	Solar	4,975.00	Intermediate/Peaking	Yes
Facility 1344	Raleigh	NC	Solar	308.00	Intermediate/Peaking	Yes
Facility 1345	Wallace	NC	Solar	1,990.00	Intermediate/Peaking	Yes
Facility 1346	Pittsboro	NC	Solar	2.26	Intermediate/Peaking	Yes
Facility 1347	Swannanoa	NC	Solar	9.46	Intermediate/Peaking	Yes
Facility 1348	Warrenton	NC	Solar	4,980.00	Intermediate/Peaking	Yes
Facility 1349	Warsaw	NC	Solar	1,900.00	Intermediate/Peaking	Yes
Facility 1350	Warsaw	NC	Solar	1,990.00	Intermediate/Peaking	Yes

Facility Name	City/County	State	Primary Fuel Type	Capacity (AC KW)	Designation	Inclusion in Utility's Resources
Facility 1351	Maxton	NC	Solar	4,980.00	Intermediate/Peaking	Yes
Facility 1352	Cameron	NC	Solar	4.60	Intermediate/Peaking	Yes
Facility 1353	Goldsboro	NC	Solar	4.01	Intermediate/Peaking	Yes
Facility 1354	Raleigh	NC	Solar	79.00	Intermediate/Peaking	Yes
Facility 1355	Weaverville	NC	Solar	3.29	Intermediate/Peaking	Yes
Facility 1356	Waynesville	NC	Solar	5.68	Intermediate/Peaking	Yes
Facility 1357	Vass	NC	Solar	4.70	Intermediate/Peaking	Yes
Facility 1358	Raleigh	NC	Solar	3.19	Intermediate/Peaking	Yes
Facility 1359	Elm City	NC	Solar	4,980.00	Intermediate/Peaking	Yes
Facility 1360	Blanch	NC	Solar	4,980.00	Intermediate/Peaking	Yes
Facility 1361	RALEIGH	NC	solar	11,000.00	Baseload	Yes
Facility 1362	FOUR OAKS	NC	Solar	450.00	Intermediate/Peaking	Yes
Facility 1363	CARY	NC	solar	144.00	Intermediate/Peaking	Yes
Facility 1364	RALEIGH	NC	Solar	500.00	Intermediate/Peaking	Yes
Facility 1365	Smyrna, NC	NC	Solar & Wind	19.60	Intermediate/Peaking	Yes
Facility 1366		NC	Solar Thermal	3.70	Intermediate/Peaking	Yes
Facility 1367	Aurora	NC	Sulfer Waste Heat Generator	10,000.00	Baseload	Yes
Facility 1368	Southport	NC	Waste Heat Generator	4,950.00	Baseload	Yes
Facility 1369	Clinton	NC	Wind	1.90	Intermediate/Peaking	Yes
Facility 1370	Marshall	NC	Wind	1.84	Intermediate/Peaking	Yes
Facility 1371	Wilmington	NC	Wind	4.20	Intermediate/Peaking	Yes
Facility 1372	Kenansville	NC	wood biomass energy	25,000.00	Baseload	Yes
Facility 1373	New Bern	NC	wood biomass energy	48,000.00	Baseload	Yes
Facility 1374	Roxboro	NC	wood biomass/tdf/coal	42,000.00	Baseload	Yes
Facility 1375	Southport	NC	wood biomass/tdf/coal	80,000.00	Baseload	Yes
Facility 1376	Rose Hill	NC	Wood Chip Biomass	120.00	Baseload	Yes
Facility 1377	Clinton	NC	Wood Chip/Steam	150.00	Baseload	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	FLORENCE	SC	Diesel Fuel	1,500.00	Intermediate/Peaking	Yes
Facility 2	BISHOPVILLE	SC	Diesel Fuel	1,500.00	Intermediate/Peaking	Yes
Facility 3	Elgin	SC	Diesel Fuel	350.00	Peaking	Yes
Facility 4	Rembert, SC	SC	Solar	50.00	Intermediate/Peaking	Yes
Facility 5	New Hill	SC	Solar	2.90	Intermediate/Peaking	Yes
Facility 6	Cheraw	SC	Solar	2.70	Intermediate/Peaking	Yes
Facility 7	Sumter	SC	Solar	3.01	Intermediate/Peaking	Yes
Facility 8	FLORENCE	SC	Solar	1.50	Intermediate/Peaking	Yes
Facility 9	Sumter	SC	Solar	2.58	Intermediate/Peaking	Yes
Facility 10	Bethune	SC	Solar	3.00	Intermediate/Peaking	Yes
Facility 11	FLORENCE	SC	Solar	1.72	Intermediate/Peaking	Yes
Facility 12	Florence	SC	Coal/wood biomass	25,000.00	Baseload	Yes
Facility 13	Darlington	SC	Solar	4.20	Intermediate/Peaking	Yes
Facility 14	Nichols	SC	Solar	11.00	Intermediate/Peaking	Yes
Facility 15		SC	Solar	9.00	Intermediate/Peaking	Yes
Facility 16	Mc Bee	SC	Solar	5.00	Intermediate/Peaking	Yes
Facility 17	CAMDEN	SC	Fossil Coal	28,000.00	Baseload	Yes
Facility 18	HARTSVILLE	SC	Process By-product	27,000.00	Baseload	Yes
Facility 19	FLORENCE	SC	Process By-product & Coal	73,000.00	Baseload	Yes

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

Table H-5 DEP 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 DEP'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
DEP	NC	Solar	275	2638.98
		Hydro	3	5.95
		Biogas	1	3.02
		Biomass induction generator	1	0.10
		Landfill Gas	3	17.75
		Unknown	1	0.06
		Wood Waste	1	5.00
DEP	**NC Total**		**285**	**2670.86**
DEP	SC	Solar	3	73.13
		Coal/wood waste	1	73.00
DEP	**SC Total**		**4**	**146.13**
DEP Total			**289**	**2816.99**

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 and substation additions. A discussion of the adequacy of DEP's transmission system is also included. Table I-1 lists the transmission 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: DEP Transmission Line Additions

	Location		Capacity	Voltage	
Year	**From**	**To**	**MVA**	**KV**	**Comments**
2016	Asheboro	Asheboro East South Line	307	115	Upgrade
2016	Ft Bragg Woodruff St	Manchester	307	115	Upgrade
2016	Vanderbilt	West Asheville	307	115	Upgrade
2018	Richmond	Raeford	1195	230	Relocate, new
2018	Ft. Bragg Woodruff St.	Raeford	1195	230	Relocate, new
2019	Asheboro	Asheboro East North Line	307	115	Upgrade

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;

The following pages represent those projects in response to Rule R8-62 parts (1) and (2).

DEP has no transmission line projects currently under construction

(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:

(3) For all other proposed lines, as the information becomes available, the following:

a. county location of end point(s);
b. approximate length;
c. typical right-of-way width for proposed type of line;
d. typical tower height for proposed type of line;
e. number of circuits;
f. operating voltage;
g. design capacity;
h. estimated date for starting construction (if more than 6 month delay from last report, explain); and
i. estimated in-service date (if more than 6-month delay from last report, explain). (NCUC Docket No. E-100, Sub 62, 12/4/92; NCUC Docket No. E-100, Sub 78A, 4/29/98.)

The following pages represent those projects in response to Rule R8-62 part (3).

Richmond – Raeford 230 kV Line loop-in

Project Description: Loop-In the existing 230 kV transmission line from the Richmond 230 kV Substation in Richmond County to the Ft. Bragg Woodruff St 230 kV Substation in Cumberland County at Raeford 230 kV Substation in Hoke County.

a. County location of end point(s); Hoke County
b. Approximate length; 5 miles
c. Typical right-of-way width for proposed type of line; 100 feet
d. Typical tower height for proposed type of line; 80 -120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 1195 MVA
h. Estimated date for starting construction; March 2015
i. Estimated in-service date; June 2018

Ft. Bragg Woodruff St – Raeford 230 kV Line loop-in

Project Description: Loop-In the existing 230 kV transmission line from the Richmond 230 kV Substation in Richmond County to the Ft. Bragg Woodruff St 230 kV Substation in Cumberland County at Raeford 230 kV Substation in Hoke County.

a. County location of end point(s); Hoke County
b. Approximate length; 5 miles
c. Typical right-of-way width for proposed type of line; 100 feet
d. Typical tower height for proposed type of line; 80 – 120 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 1195 MVA
h. Estimated date for starting construction; March 2015
i. Estimated in-service date; June 2018

DEP Transmission System Adequacy

Duke Energy Progress 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 DEP transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability. DEP works with DEC, NCEMC and ElectriCities to develop an annual NC Transmission Planning Collaborative (NCTPC) plan for the DEP and DEC 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 DEP's Transmission Planning Summary 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. The transmission system is planned to ensure that no equipment overloads and adequate voltage is maintained to provide reliable service. The most stressful scenario is typically at peak load with certain equipment out of service. A thorough screening process is used to analyze the impact of potential equipment failures or other disturbances. As problems are identified, solutions are developed and evaluated.

Transmission planning and requests for transmission service and generator interconnection are interrelated to the resource planning process. DEP currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Summary 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 and the North Carolina Interconnection Procedures.

Southeastern Reliability Corporation (SERC) audits DEP every three years for compliance with NERC Reliability Standards. Specifically, the audit requires DEP 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 DEP in May 2011. The scope of this audit included Transmission Planning

Standards TPL-002-0.a and TPL- 003-0a. For both Standards, DEP received "No Findings" from the audit team.

DEP 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. Each reliability group's 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 DEP'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:
42 MW for North Carolina
10 MW for South Carolina

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

APPENDIX K: 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	App H	NC R8-60 (d)	Yes
Assessment of Alternative Supply-Side Energy Resources	Ch 5,6 & App B, D, F	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, B, D, 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, 8 & App A, B, F	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	Ch 5, 6 & App B, D, F	E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 14	Yes
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	App D	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)	Yes
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	App B	E-2, Sub 960, Order Approving Plan, dated 1/28/10, ordering paragraph 2 (Wayne County CCs CPCN)	Yes

The Duke Energy Progress

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

September 1, 2014

NC REPS Compliance Plan
Table of Contents

I. INTRODUCTION

Duke Energy Progress (DEP 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 Progress 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 Progress' 2014 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); and (3) 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. REPS COMPLIANCE OBLIGATION

Duke Energy Progress calculates its NC REPS Compliance Obligations[6] 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 the Town of Sharpsburg, the Town of Stantonsburg, the Town of Lucama, the Town of Black Creek, Town of Winterville and the City of Waynesville (collectively referred to as Wholesale or Wholesale Customers)[7]. Table 1 below shows the Company's retail and Wholesale customers' REPS Compliance Obligation.

[6] For the purposes of this Compliance Plan, Compliance Obligation is more specifically defined as the sum of Duke Energy Progress' 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 Progress 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 Progress on behalf of the Wholesale Customers.

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

Table 1: Duke Energy Progress' NC REPS Compliance Obligation

Compliance Year	Previous Year DEP 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	35,886,571	205,300	36,091,870	25,264	25,264	48,752	3%	1,082,756
2015	38,222,629	208,812	38,431,441	53,804	26,902	207,983	6%	2,305,886
2016	38,684,865	209,856	38,894,721	54,453	54,453	268,408	6%	2,333,683

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 25,264 RECs in 2014. Based on forecasted retail sales, the Solar Set-Aside is projected to be approximately 53,804 RECs and 54,453 RECs in 2015 and 2016, respectively.

The Company's plan for meeting the Solar Set-Aside in the Planning Period consists of multiple solar REC purchase agreements with third parties. These agreements include contracts with multiple counterparties to procure solar RECs from both solar PV and solar water heating installations. Additional details with respect to the REC purchase agreements are set forth in Exhibit A.

Also, the Company maintains a residential solar PV program, which offers incentives to customers who install solar. In exchange, the Company receives RECs created by the systems for 5 years. By year-end 2014, the Company expects total program participation of approximately 2.5MW of solar PV from around 650 program participants.

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), for calendar year 2014, at least 0.07% of prior year total retail electric energy sold in aggregate by utilities in North Carolina must be supplied by energy derived from swine waste. In 2015 and 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 25,264 RECs in 2014, 26,902 RECs in 2015, and 54,453 RECs in 2016.

In spite of Duke Energy Progress' active and diligent efforts to secure resources to comply with its Swine Set-Aside requirements, the Company has been unable to procure 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.

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 2015 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 30%, the Company's Poultry Set-Aside is estimated to be 48,752 RECs in 2014, 207,983 RECs in 2015, and 268,408 in 2016.

As a result of Duke Energy Progress' 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 waste 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 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 Progress is required to comply with its Total Obligation in 2014, 2015, and 2016 by submitting for retirement a total volume of RECs equivalent to 3% of retail sales in North Carolina in the prior year: approximately 1,082,756 RECs in 2014, 2,305,886 RECs in 2015, and 2,333,683 RECs in 2016. This requirement, net of the Solar, Swine, and Poultry Set-Aside requirements, is estimated to be 983,475 RECs in 2014, 2,017,197 RECs in 2015, and 1,956,370 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 with Energy Efficiency (EE) savings, which is the maximum allowable amount under NC Gen. Stat. § 62-133.7(b)(2)c. The Company continues to develop and offer its customers new and innovative EE programs that deliver savings and count towards its NC REPS requirements. Please refer to Appendix D of the Company's 2013 Integrated Resource Plan (IRP) filed concurrently with this Compliance Plan in this docket, for descriptions of each of these programs. The Company forecasts creation of 1,218,563 EECs in 2014, 1,426,736 in 2015, and 1,646,920 in 2016.

2. Hydroelectric Power

Duke Energy Progress plans to use hydroelectric power from two sources to meet the General Requirement in the Planning Period: (1) Wholesale Customers' Southeastern Power Administration (SEPA) allocations; and (2) hydroelectric generation suppliers whose facilities have received Qualifying Facility (QF or QF Hydro) status. 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 addition, RECs from QF Hydro facilities will be used towards the General Requirements of Duke Energy Progress' retail customers. Please see Exhibit A for more information.

3. Biomass Resources

Duke Energy Progress 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.

4. Wind

Duke Energy Progress 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 Progress 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 also benefit from generous supportive Federal and State policies that are expected to be in place through the middle of this decade. While uncertainty remains around possible alterations or extensions of policy support, as well as the pace of future cost declines, the Company fully expects solar resources to contribute to our compliance efforts beyond the solar set-aside minimum threshold for NC REPS during the Planning Period.

6. Review of Company's General Requirement Plan

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

E. SUMMARY OF RENEWABLE RESOURCES

The Company has evaluated, procured, and/or developed a variety of types of renewable and energy efficiency resources to meet its NC REPS requirements within the compliance Planning Period. As noted above, several risks and uncertainties exist across the various types of resources and the associated parameters of the NC REPS requirements. The Company continues to carefully monitor opportunities and unexpected developments across all facets of its compliance requirements. Duke Energy Progress 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 2014 variable rate represents the avoided cost rate in Schedule CSP-29 (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 2014 long-term rates represent the annualized avoided cost rates proposed by the Company and approved in the Commission's *Order on Motion to Suspend Avoided Cost Rates*, issued in Docket No. E-100, Sub 136 (December 21, 2012). The 2014 and 2015 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	46.37	37.35	[redacted]
2016	47.44	38.53	[redacted]
2017	47.05	40.20	[redacted]

PROJECTED AVOIDED ENERGY AND CAPACITY COST			
	On-Peak Energy(1) ($/MWh)	**Off-Peak Energy(1) ($/MWh)**	[redacted]
2015	41.61	37.00	[redacted]
2016	40.72	38.67	[redacted]
2017	45.11	39.30	[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.

[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	35,886,571	38,222,629	38,684,865
Wholesale MWh Sales	205,300	208,812	209,856
Total MWh Sales	36,091,870	37,431,441	38,894,721

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

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

		2013 (Actual)	2014 (Projected)	2015 (Projected)	2016 (Projected)
Residential Accts		1,146,549	1,135,624	1,151,518	1,168,215
General Accts		187,321	194,338	195,194	196,182
Industrial Accts		2,059	3,589	3,614	3,640

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	$ 149,270,585	$ 146,070,745	$ 170,865,095
Recovered through the Fuel Rider	$ 126,885,086	$ 124,560,147	$ 135,002,196
Total incremental costs (REPS Rider)	$ 22,385,499	$ 21,510,598	$ 35,862,899
Total including Regulatory Fee	$ 22,414,683	$ 21,538,641	$ 35,909,653
Projected Annual Cost Caps (REPS Rider)	$ 43,915,738	$ 71,350,928	$ 72,044,678

EXHIBIT A

Duke Energy Progress, LLC's 2014 REPS Compliance Plan
Duke Energy Progress' Renewable Resource Procurement from 3rd Parties
(signed contracts as of July 1, 2014)

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*Indicates bundle purchase of RECs and energy, as opposed to REC-only purchase.
Contract list does not include Residential SunSense Solar PV participants

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