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November 1, 2016

VIA ELECTRONIC FILING

The Honorable Jocelyn G. Boyd
Chief Clerk/Administrator
Public Service Commission of South Carolina
101 Executive Center Drive, Suite 100
Columbia, South Carolina 29210

Re: **Duke Energy Progress, LLC's 2016 Integrated Resource Plan**

Dear Mrs. Boyd:

Pursuant to S.C. Code Ann. § 58-37-40, enclosed for filing is Duke Energy Progress, LLC's ("DEP" or the "Company") 2016 Integrated Resource Plan Annual Report ("2016 DEP IRP"). In addition to the Public Version of the 2016 DEP IRP being electronically filed with the Commission, we are also hand delivering to the Commission and the Office of Regulatory Staff copies of the Public and Confidential Versions.

Portions of the 2016 DEP IRP contain certain confidential information that should be protected from public disclosure. Pages 141-144 and pages 155-156 contain confidential and proprietary information regarding Busbar Screening Curves and wholesale sales and purchased power contracts. Public disclosure of this information would harm DEP's ability to negotiate and sell or procure cost-effective purchases, discourage potential bidders from participating in requests for proposals, and impede DEP's ability to compete in the wholesale market.

Accordingly the Company is filing these documents under seal; they should be treated as confidential pursuant to Order No. 2005-226, "Order Requiring Designation of Confidential Materials" and 26 S.C. Code Ann. Regs. 103-804(s)(2) and under the Freedom of Information Act, S.C. Code Ann. § 30-4-10 *et seq*. and protected from public disclosure.

Please consider this correspondence as DEP's Motion for Confidential Treatment of the above-referenced information.

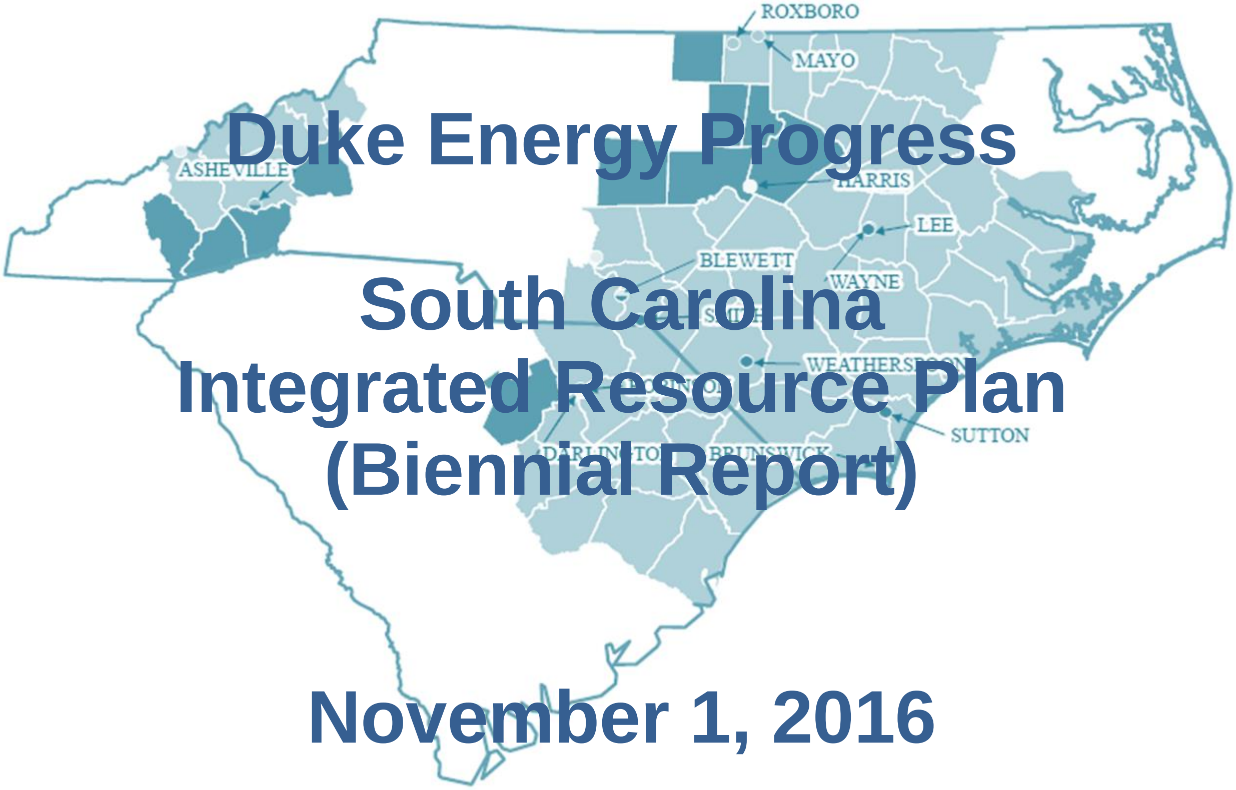
Thank you for your consideration. Please contact me should you have any questions.

Sincerely,

Rebecca J. Dulin

Enclosure

cc: Dawn Hipp, ORS – Director of Utilities, Safety & Transportation
Nanette S. Edwards, ORS - Deputy Executive Director
Jeffrey M. Nelson, ORS - Chief Counsel & Director of Legal Services
Shannon Bowyer Hudson, ORS - Deputy Director of Legal Services
Heather Shirley Smith, Deputy General Counsel



Duke Energy Progress

South Carolina
Integrated Resource Plan
(Biennial Report)

November 1, 2016

PUBLIC

DEP 2016 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

Overview

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 meet the forecasted electricity requirements for our customers over the next 15 years.

The 2016 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 may change over time as variables such as the projected load forecasts, fuel price forecasts, environmental regulations, technology performance characteristics, and other outside factors change.

The proposed plan will meet the following objectives:

- Provide reliable electricity especially during peak demand periods by maintaining adequate reserve margins. Peak demand refers to the highest amount of electricity being consumed for any given hour across DEP's entire system.
- Add new resources at the lowest reasonable cost to customers. These resources include a balance of energy efficiency programs (EE), demand-side management programs (DSM), renewable resources, nuclear generation and natural gas generation.
- Improve the environmental footprint of the portfolio by meeting or exceeding all federal, state and local environmental regulations.

A New Era – Plans to Specifically Include Consideration of Winter Demand for Power

Historically, DEP's resource plans have projected the need for new resources based primarily on the need to meet summer afternoon peak demand projections. For the first time in the 2016 IRP, DEP is now developing resource plans that also include new resource additions driven by winter peak demand projections inclusive of winter reserve requirements. The completion of a comprehensive reliability study demonstrated the need to include winter peak planning into the IRP process. The study recognized the growing volatility associated with winter morning peak demand conditions such as those observed during recent polar vortex events. The study also incorporated the expected growth in "summer-oriented resources" such as solar facilities and air conditioning load control programs that provide valuable assistance in meeting summer afternoon peak demands on the system but do little to assist in meeting demand for power on cold winter mornings. As a result of the reliability study, DEP has now added a winter planning reserve target of 17% to its 2016 IRP.

<u>The Road Ahead − Determining Customer Electricity Needs 2017 – 2031</u>

The 2016 IRP identifies the incremental amount of electricity our customers will require over the next 15 years using the following basic formula:

Growth in Peak Demand and Energy Consumption	+	Resource Retirements	=	New Resource Needs

The annual energy consumption growth rate for all retail and wholesale customers is forecasted to be 1.1%. The growth rate is offset by projections for utility-sponsored EE impacts, reducing the projected growth rate by 0.2% for a net growth rate of 0.9% after accounting for energy efficiency. Peak demand growth net of EE is expected to grow slightly faster than overall energy consumption with an average projected growth rate of 1.3% (winter). Peak demand refers to the highest hourly level of energy consumption, given expected weather, throughout the year. The Company also carries reserve capacity to provide reliable supply during extreme weather conditions.

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

- Commercial class, mainly driven by offices, education and retail, is the fastest growing class with a projected growth rate of 1.3%.
- Industrial class has a projected growth rate of 0.8%.
- Residential class has a projected growth rate of 1.1%.

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 power plants have been replaced with a combination of renewable energy, EE, DSM and state-of-the-art natural gas generation facilities.

In November 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 approximately 1,700 MW/1,600 megawatts (MW) (winter/summer) at 12 older coal units in favor of cleaner burning natural gas plants that comply with stringent air, water and waste rules. Additionally, Darlington combustion turbine (CT) Unit 11 (67 MW/52 MW (winter/summer)) was retired in November of 2015, further reducing older combustion turbine generation. Since 2012, DEP has retired 250 MW/200 MW (winter/summer) of older CT units. Over the 15-year planning horizon, the Company will continue to modernize its fleet with the planned retirements of older coal units and CT units including:

- Sutton CT Units 1, 2A and 2B, located in Wilmington, NC, totaling 76 MW/61MW (winter/summer), by 2017.
- Asheville Coal Units 1-2, located in Asheville, NC, totaling 384 MW/378 MW (winter/summer) by November 2019.
- Darlington CT Units 1 - 10, located in Darlington County, SC, totaling 645 MW/501 MW (winter/summer) by 2020.
- Blewett CT Units 1 – 4, located in Lilesville, NC, totaling 68 MW/52 MW (winter/summer), by 2027.
- Weatherspoon CT Units 1 – 4, located in Lumberton, NC, totaling 164 MW/128 MW (summer), by 2027.

The ultimate timing of unit retirements can be influenced by factors that impact the economics of continued unit operations. Such factors include changes in relative fuel prices, operations and maintenance costs and the costs associated with compliance of evolving environmental regulations. As such, unit retirement schedules are expected to change over time as market conditions change.

Western Carolinas Modernization Project – Energy Innovation Asheville

The Western Carolinas Modernization Project is an energy innovation project for the Asheville area in the western region of DEP. The goal of this project is to partner with the local community and elected leaders to help transition western NC to a cleaner, smarter and more reliable energy future.

Duke Energy Progress is committed to this partnership to promote the efficient use of energy in the region. The project allows for the retirement of the existing Asheville coal units and would replace the capacity with efficient natural gas units and solar. Additionally, the project calls for increased promotion and access to new and existing EE/DSM programs, deliberate investment in distributed energy resources and more customer involvement to determine what products and services are considered valuable.

Strategy to Meet New Resource Needs

Natural Gas

Currently, natural gas resources such as combined cycles (CC) and combustion turbines only make up 35% of the winter generating capacity in DEP. The 2016 IRP identifies the need for new natural gas resources 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:

- Complete 100 MW/84 MW (winter/summer) Sutton fast start/black start CT in 2017.
- Complete 560 MW/495 MW (winter/summer) natural gas CC at Asheville, NC in late 2019.
- Plan for a 1,221 MW/1,123 MW (winter/summer) natural gas CC in 2022.
- Plan for a potential 186 MW/161 MW (winter/summer) CT in late 2023.
- Plan for 468 MW/435 MW (winter/summer) of CT capacity in 2023.
- Plan for 468 MW/435 MW (winter/summer) of CT capacity in 2026.
- Plan for 468 MW/435 MW (winter/summer) of CT capacity in 2028 and 2029.
- Plan for 1,404 MW/1,305 MW (winter/summer) of CT capacity in 2031.

Nuclear Power

The 2016 IRP continues to support new nuclear generation as a carbon-free, cost-effective, reliable option within the Company's resource portfolio. Historically low natural gas prices, ambiguity regarding the timing and impact of environmental regulations and uncertainty regarding the potential to extend the licenses of existing nuclear units affects the timing of the need for new nuclear generation. The Company views all of its nuclear plants as excellent candidates for license extensions, however to date no nuclear plant licenses have been extended to operate from 60 years to 80 years. DEP will continue to study the possibility of license extension from the current 60 years to 80 years at its nuclear stations. Given the uncertainty of license extension, the IRP Base Case does not assume license extension at this time, but rather considers relicensing as a sensitivity to the Base Case.

While the 2016 Base Case does not call for DEP to construct additional self-owned nuclear generation before 2030, it is considered in the IRP's alternative Joint Planning Case. The Joint Planning Case projects shared DEP-DEC ownership of the W.S. Lee Nuclear Facility in 2026.

Nuclear generation currently serves approximately half of the total demand for energy on the system and continues to be the primary source of carbon-free generation in the Company's portfolio.

Renewable Energy and Solar Resources

Renewable mandates, extended federal tax subsidies and declining technology costs make solar energy the Company's primary renewable energy resource in the 2016 IRP. DEP continues to add solar to its resource mix through Purchased Power Agreements (PPAs), Renewable Energy Credit (REC) purchases and Qualifying Facilities (QFs) under the Public Utility Regulatory Policy Act (PURPA). The 2016 IRP projects:

- Increasing all solar energy resources from 1,710 MW in 2017 to 3,270 MW in 2031.
- Complying with NC Renewable Energy and Energy Efficiency Portfolio Standards (NC REPS or REPS) through a combination of solar, other renewables, EE and REC purchases.
- Meeting increasing goals of the South Carolina Distributed Energy Resource Program (SC DER) through 2020.
- Meeting growing customer demand for renewable resources outside of mandated compliance programs.
- Planning for incremental solar resources that are put onto the system as QFs under PURPA.

While the Company has aggressively pursued solar as a renewable resource, the 2016 IRP recognizes and plans for its operational limitations. Solar energy is an intermittent renewable energy source that cannot be dispatched to meet changing customer demand during all hours of the day and night or through all types of weather. Solar has limited ability to meet peak demand conditions that occur during early morning winter hours or summer evening hours. As such, solar energy must be combined with resources such as EE, DSM, natural gas and nuclear generation to make up the Company's diverse resource portfolio to ensure system reliability.

Energy Efficiency and Demand-Side Management

Existing programs, along with new EE and DSM programs approved since the last biennial IRP 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 extensive EE and DSM program offerings, successfully increasing customer adoption. The Company is forecasting continued energy and capacity savings from both EE and DSM programs through the planning period as depicted in the table below.

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

Projected EE and DSM Energy and Capacity Savings		
Year	**Energy (MWh)**	**Capacity (MW)**
2017	344,700	476
2031	2,284,700	829

Cost-effective EE and DSM programs can help delay the Company's need to construct and operate new generation. The Base Case includes 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.

Alternative Generation

DEP continues to explore alternative generation types for feasibility and economic viability to potentially meet future customer demand. As these generation types become viable and economically feasible, the Company will consider them in the planning process. In the 2016 IRP, capacity from Combined Heat and Power (CHP) projects have been increased in the resource plan. CHP projects efficiently provide both power to the grid while simultaneously meeting the steam requirements of large institutions and industries in the Carolinas. The current CHP projection for DEP is 66 MW/60 MW (winter/summer) of CHP in the 2019 – 2021 timeframe.

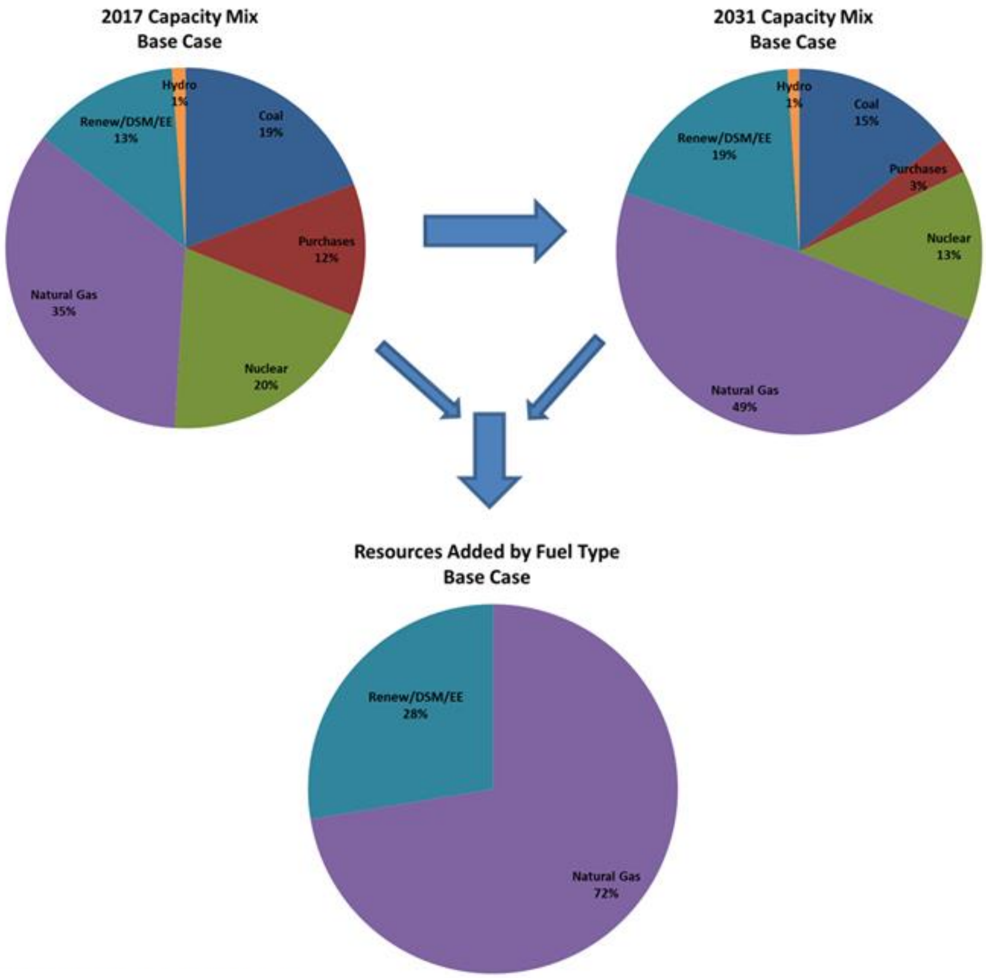
Strong Trend Toward Cleaner, More Environmentally Friendly Generation

When viewed in total, approximately 54% of DEP and DEC's collective energy needs in 2017 are met by emission-free resources. This includes nuclear energy, hydro-electric power, DSM, EE and renewable energy. The remaining 46% of the energy portfolio includes clean, efficient natural gas units and coal plants that are equipped with state-of-the-art emission technology. Based upon the Environmental Protection Agency (EPA) carbon standards for new generation, the 2016 IRP does not call for the construction of any new coal plants.

The EPA's Clean Power Plan continues to influence the development of the Company's resource plans. While the CPP was stayed by the U.S. Supreme Court in 2016, the Company continues to plan for a range of carbon dioxide (CO_2) legislative outcomes. As such, DEP's base resource plan assumes some level of carbon emission restrictions consistent with the CPP, while alternate views of CO_2 legislative outcomes were considered as sensitivities.

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 represent 28% of the Company's new installed capacity over the study period. The remaining 72% of future new capacity will come from new natural gas generation. In aggregate, the incremental resource additions identified in the 2016 IRP contribute to an economic, reliable and increasingly clean energy portfolio for the citizens of North Carolina and South Carolina.

Figure Exec-1: 2017 & 2031 Capacity Mix and Sources of Incremental Capacity Additions



Note: Capacity based on winter ratings (renewables based on nameplate)

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 of this document provide an overview of the inputs, analysis and results included in the 2016 IRP. In addition to the Base Case plan, five 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 2016 IRP.

2. SYSTEM OVERVIEW

DEP's service area covers approximately 32,485 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 1.52 million residential, commercial and industrial customers, the Company also sells wholesale electricity to incorporated municipalities and to public and private utilities.

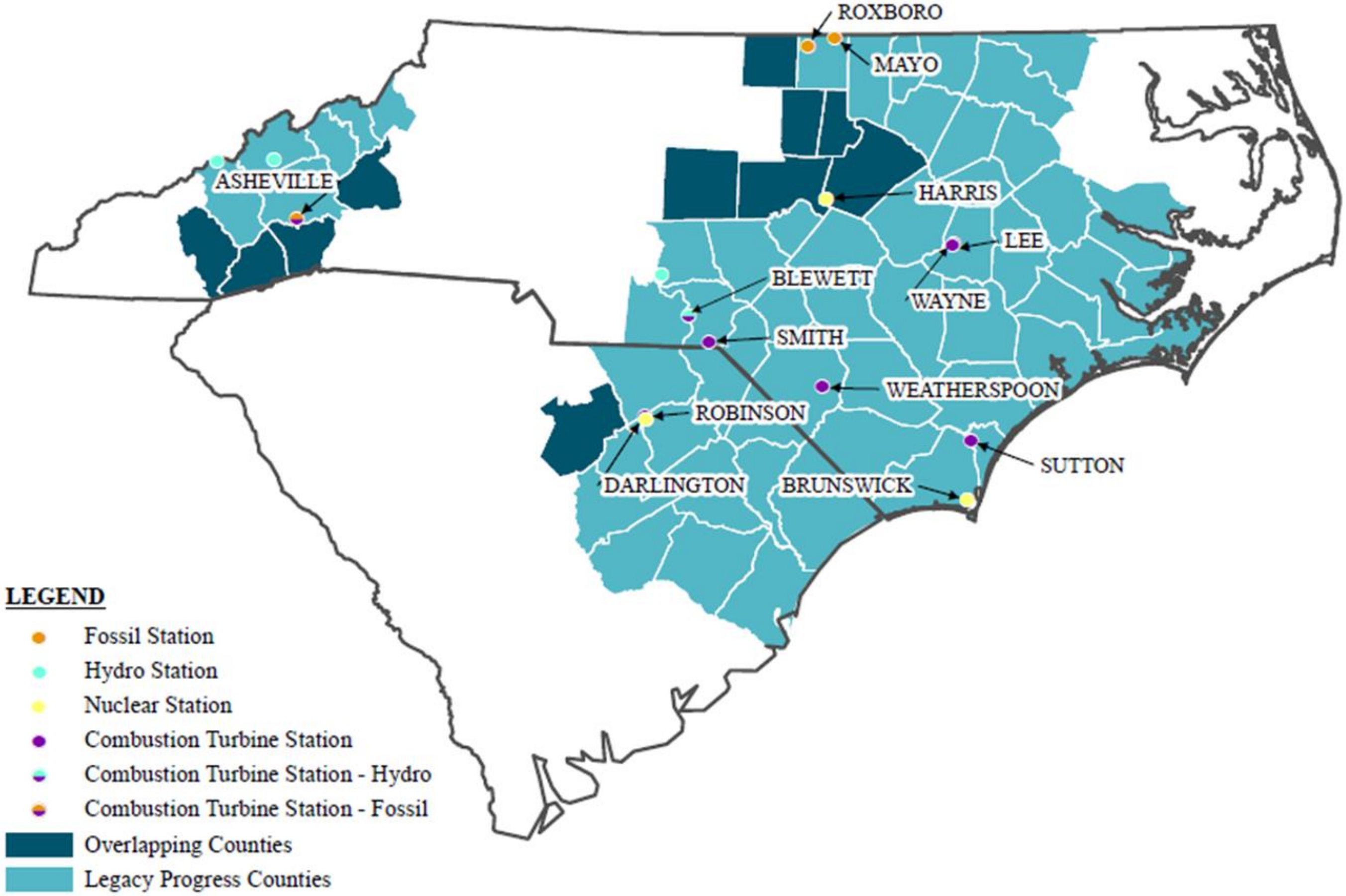
DEP currently meets energy demand, in part, by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:

- Three nuclear generating stations with a combined net capacity of 3,698 MW/3,539 MW (winter/summer)
- Three coal-fired stations with a combined capacity of 3,592 MW/3,544 MW (winter/summer)
- Four hydroelectric stations with a combined capacity of 227 MW (winter/summer)
- Ten combustion turbine stations including four combined cycle units with a combined capacity of 6,455 MW/5,563 MW (winter/summer)
- Three utility-owned solar facilities with a combined firm capacity of 44.4 MW

DEP's power delivery system consists of approximately 67,800 miles of distribution lines and 6,300 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 (TVA), 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).

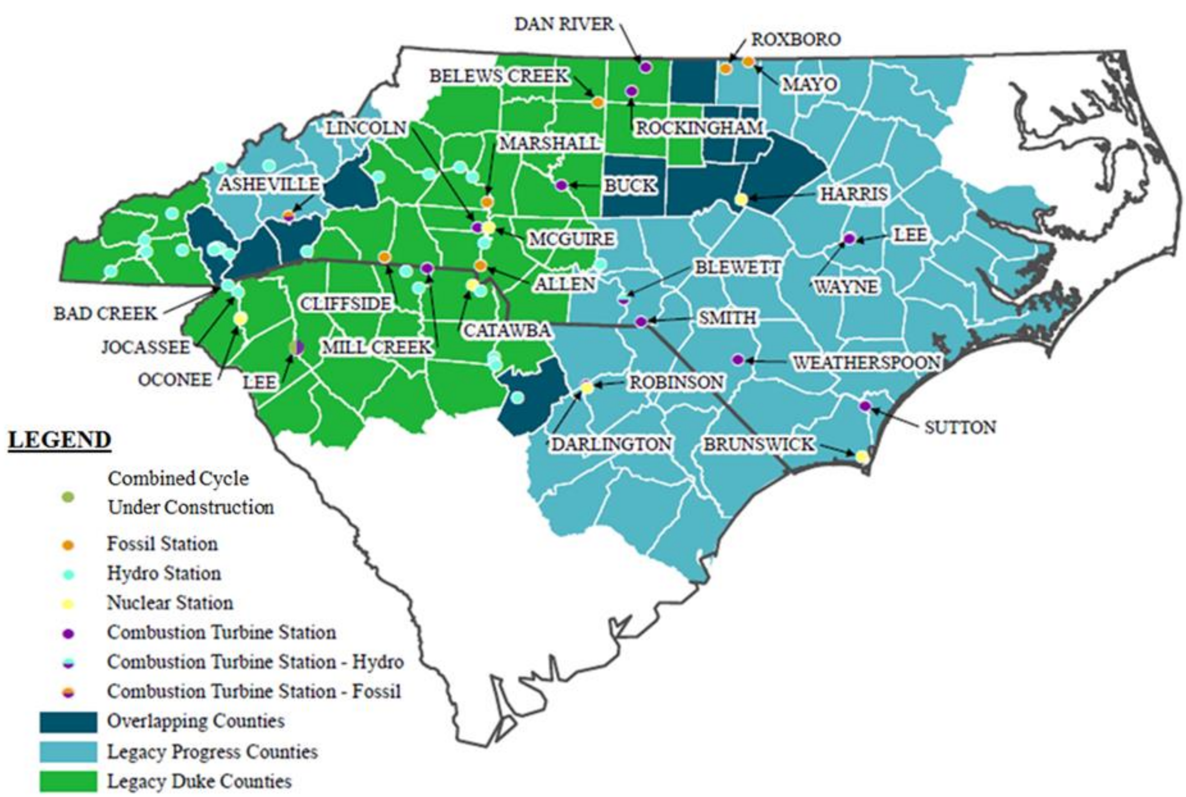
The map on the following page provides a high-level view of the DEP service area.

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 2016 Forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2017 – 2031 and represents the needs of the Retail and Wholesale Customers.

Energy projections are developed with econometric models using key economic factors such as income, electricity prices, industrial production indices, along with weather, appliance efficiency trends, rooftop solar trends, and electric vehicle trends. Population is also used in the Residential customer model. Regression analysis is utilized and has yielded consistently reasonable results over the years.

The economic projections used in the Spring 2016 Forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of North Carolina and South Carolina.

The Retail forecast consists of the three major classes: Residential, Commercial and Industrial.

The Residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electric price and appliance efficiencies.

The usage per customer forecast was derived using a Statistical Adjusted End-Use Model (SAE). This is a regression-based framework that uses projected appliance saturation and efficiency trends developed by Itron using Energy Information Administration (EIA) data. It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models. The outlook for usage per customer is essentially flat through much of the forecast horizon, so most of the growth is primarily due to customer increases. The projected energy growth rate of Residential in the Spring 2016 Forecast after all adjustments for Utility EE programs, Solar and Electric Vehicles from 2017-2031 is 1.1%.

The Commercial forecast also uses an SAE model in an effort to reflect naturally occurring as well as government mandated efficiency changes. The three largest sectors in the Commercial class are Offices, Education and Retail. Commercial is expected to be the fastest growing class, with a projected energy growth rate of 1.3% after adjustments.

The Industrial class is forecasted by a standard econometric model with drivers such as total manufacturing output, textile output, and the price of electricity. Overall, Industrial energy sales are expected to grow 0.8% over the forecast horizon, after all adjustments.

Peak Demand and Energy Forecast

If the impacts of new Duke Energy Progress UEE[1] programs are included, the projected compound annual growth rate for the summer peak demand is 1.1%, while winter peaks are forecasted to grow at a rate of 1.3%. The forecasted compound annual growth rate for annual energy consumption is 0.9% after the impacts of UEE programs are subtracted.

The Spring 2016 Forecast is lower than the Spring 2015 Forecast, with a growth in the summer peak of 1.3% in the 2015 forecast versus 1.1% in the new forecast. The Spring 2016 Forecast is lower due to large Industrial plant closings in recent years, strong UEE accomplishments in recent years, stronger projected Commercial heating and cooling efficiencies, and a reduction in the projected Wholesale outlook.

[1] The term UEE is utilized in the load forecasting sections which represents utility-sponsored EE impacts net of free riders. The term "Gross EE" represents UEE plus naturally occurring energy efficiency in the marketplace.

The load forecast projection for energy and capacity including the impacts of EE that was utilized in the 2016 IRP is shown in Table 3-A.

Table 3-A Load Forecast with Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2017	13,127	13,158	65,000
2018	13,234	13,277	65,414
2019	13,385	13,442	65,952
2020	13,444	13,542	65,869
2021	13,599	13,728	66,442
2022	13,753	13,918	67,137
2023	13,919	14,107	67,873
2024	14,083	14,300	68,751
2025	14,249	14,488	69,413
2026	14,435	14,689	70,184
2027	14,601	14,874	70,938
2028	14,792	15,082	71,855
2029	14,973	15,283	72,558
2030	15,164	15,497	73,388
2031	15,365	15,719	74,166

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 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 resource options 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 technical, economic and achievable potential for EE within the DEP service area. 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. An updated Market Potential Study is currently underway and the results of that study should be available in time for the next DEP IRP process.

DEP prepared a Base Portfolio savings projection that was based on DEP's five year program plan for 2016-2020. For periods beyond 2020, the Base Portfolio assumed that the annual savings projected for 2020 would continue to be achieved in each year thereafter until such time as the total cumulative EE projections reached approximately 60% of the Economic Potential as estimated by the Market Potential Study described above. Beyond reaching 60% of the Economic Potential, sufficient EE savings would be added to keep up with growth in the customer load.

DEP also prepared a High Portfolio EE savings projection that assumed that the same types of programs offered in the Base Portfolio, including potential new technologies, can be offered at higher levels of participation provided that additional money is spent on program costs to encourage additional customers to participate.

Additionally, for both the Base and High Portfolios described above, DEP included an assumption that, when the EE measures included in the forecast reach the end of their useful lives, the impacts associated with these measures are removed from the future projected EE impacts. This concept of "rolling off" the impacts from EE programs is explained further in Appendix C.

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 demand response impacts are also discussed in Appendix D.

5. RENEWABLE ENERGY STRATEGY / FORECAST

Since the last IRP was filed, the growth of renewable generation in the US continues to outpace that of non-renewable generation. In 2015, over 13,000 MW of wind and solar capacity were installed nationwide compared to 6,500 MW for natural gas, coal, nuclear, and other technologies. Most of the renewable growth is occurring in states with higher than average retail rates, renewable state mandates like NC REPS and/or tax incentives. Additionally, the requirements of the Public Utilities Regulatory Policy Act (PURPA) have driven renewable generation growth, especially in states with higher avoided cost rates and/or contract terms that are favorable to Qualifying Facilities (QFs). North Carolina has experienced this growth firsthand. The state ranked in the top three in the country in universal solar installations (>1MW in size) during the last two years, with the majority of that generating capacity owned by non-utility third parties.

Renewable mandates, substantial federal and state tax subsidies, and declining installed costs make solar capacity the Company's primary renewable energy resource in the 2016 IRP. The 2016 IRP makes the following key assumptions regarding renewable energy:

- Solar capacity increases from 1,710 MW in 2017 to 3,270 MW in 2031[2] (Base Case);
- Compliance with the NC REPS continues to be met through a combination of solar, other renewables, EE, and REC purchases;
- Achievement of the SC DER Program goal of 39 MW of solar capacity located in DEP-South Carolina (DEP-SC);
- With no change in policy, and even with the expiration of the NC state tax incentive in 2015, additional renewable capacity, particularly in the form of solar, will continue unabated, above and beyond the NC REPS requirements, driven by continued expected technology cost declines, local, state, and/or Federal incentives for these technologies, and PURPA implementation unique to North Carolina.

NC REPS Compliance

DEP is committed to meeting the requirements of NC REPS, including the poultry waste, swine waste, and solar set-asides, and the general requirement, which will be met with additional solar, hydro, biomass, landfill gas and EE resources. NC REPS allows for compliance utilizing not only renewable energy resources supplying bundled energy, RECs, and EE, but also by procuring unbundled RECs (both in-state and out-of-state) and thermal RECs. Therefore, the actual

[2] Solar capacities are adjusted to account for an annual 0.50% degradation of nameplate capacity.

renewable energy delivered to the DEP system is impacted by the amount of EE, unbundled RECs and thermal RECs utilized for compliance.

Based on currently signed projects and projections of what will materialize from the interconnection queue, DEP will be well positioned to meet the general NC REPS compliance requirement in the future.

Solar: PURPA and the Interconnection Queue

The rapid growth of new solar facilities continues to dominate the renewable energy market landscape. As discussed above, DEP purchases solar energy from non-utility generators in North Carolina to comply with NC REPS requirements. In addition to the NC REPS compliance requirements, however, DEP is also subject to PURPA, which requires that it purchase power from QFs at its avoided cost, regardless of the utility's need for such energy. Thus, another driver of the significant growth in solar purchases relates to the avoided cost rates a utility must pay for this power under PURPA. The utility's avoided costs rates, as approved by the NCUC, are a critical input for forecasting renewable penetration from QFs. Expected avoided costs, which are a key input to the rates paid to solar generators, are subject to factors such as commodity price volatility, regulatory changes, system operating conditions, and weather. Therefore, determining the future value of avoided costs is not easy and cannot be done with a high degree of accuracy.

Given the currently approved avoided cost rates and standard offer terms in NC, the NC REPS mandate, continuing impacts from the 35% North Carolina Renewable Energy Investment Tax Credit Safe Harbor Provision (which expired at the end of 2015), and the 30% Federal Solar Investment Tax Credit (ITC) (which was extended in December 2015), the QF market remains very active in the DEP service territory. Illustrating this trend are these facts:

- DEP had over 800 MW-AC (includes compliance and non-compliance MW) of third-party solar facilities on its system through the end of 2015, with close to half of the facilities interconnecting in 2015.
- When renewable resources were evaluated for the 2016 IRP, DEP reported another ~450 MW of third-party solar under construction and over 3,000 MW in the interconnection queue, including over 600 MW requested during the first quarter of 2016.

Projecting future solar connections from the interconnection queue, and its impact on future resource needs, presents a significant challenge as a large number of projects and interconnection requests have historically been cancelled or their ownership has changed hands numerous times. Given the size of the DEP and DEC queues, the time to complete the process from interconnection request to project completion where a facility is connected and supplying energy to the grid, often takes 2 years or more (please refer to Docket E-100 Sub 101A). The interconnection queue as of June 30, 2016 is provided in Appendix H.

While forecasting what will materialize from the current queue is difficult, projecting long-term solar growth is even more challenging. There are a number of factors that are difficult to predict, but necessary to estimate future renewable generation. These variables include, but are not limited to, interest rates, technology costs, construction and maintenance costs, energy and tax policy and operational constraints such as interconnection feasibility or land availability. In total, DEP expects 1,155 MW-AC of nameplate non-compliance mandated PURPA solar capacity by 2031.

Utility-Owned Solar and Integration

DEP continues to evaluate utility-owned solar additions to support operational flexibility. For example, DEP recently constructed, and is owning and operating four new utility-scale solar projects as part of its efforts to encourage emission free generation resources and help meet its compliance targets, totaling 141 MW-AC:

- Camp Lejeune Solar Facility – 13MW, located in Onslow County, placed in service in November 2015;
- Warsaw Solar Facility – 65MW, located in Duplin County, placed in service in December 2015;
- Fayetteville Solar Facility – 23MW, located in Bladen County, placed in service in December 2015; and
- Elm City Solar Facility – 40MW, located in Wilson County, placed in service in March 2016.

While there is uncertainty in the rate of decline in the cost of solar over time, in most scenarios evaluated in the IRP planning process, additional utility-owned solar was not selected above and beyond the total capacity expected for NC REPS compliance, PURPA puts, and customer product offerings like SC DER. As described in more detail in Appendix A, scenarios where solar was selected required assumptions in which lower installed solar cost and/or higher emissions constraints were utilized relative to the Base Case assumptions. Such price declines may be realized, and the Company will continue to position itself for delivering quality, cost-effective projects that leverage the utility's scale and knowledge. DEP continues to build its relationships with suppliers, Engineering, Procurement, and Construction Contractors (EPCs), and other entities to create greater efficiencies in the supply chain, reduce construction costs, reduce operating and maintenance costs (O&M), and enhance system design. DEP will continue to evaluate how to increase its ownership of renewable generation to expand its portfolio of clean energy resources, meet future customer demand, and comply with evolving government regulations that promote the use of such resources.

Positioning itself to properly integrate renewable resources to the grid, especially solar, is critical. The Company is already observing that significant volumes of solar capacity result in excess energy challenges during the middle of the day during mild conditions when overall system demand is low. As a result, the Company sees an increasing need for operational control of the solar facilities connected to the grid. Additionally, the intermittency of solar output will require the Company to evaluate and invest in technologies to provide solutions for voltage, Volt Ampere Reactive (VaR), and/or higher ancillary reserve requirements. DEP expects that it can safely and reliably integrate renewable resources like solar through a combination of utility-owned assets and cooperation with third parties. DEP will evaluate the potential for acquiring facilities, where appropriate, to help ensure the Company has needed operational control, while minimizing the costs associated with system integration.

SC DER Solar and Customer Program Solar

In addition to PURPA and NC REPS compliance solar, solar growth has also been embraced with customer-oriented strategies such as SC DER.

In 2015, the Company's DER plan was approved by the PSCSC, thus allowing the Company to pursue a portfolio of initiatives designed to increase the solar capacity located in the Company's South Carolina service area. The program contains three tiers; each is equivalent to 1% of the Company's estimated average South Carolina retail peak demand (or 13 MW of nameplate solar capacity). The plan calls for a total of ~39MW of solar capacity[3] distributed across three tiers:

- Tier I: 13 MW of solar capacity from facilities each >1 MW and less than 10 MW in size.
- Tier II: 13 MW met via behind-the-meter rooftop solar facilities ≤1 MW for residential, commercial, and industrial customers with at least a quarter of that capacity from facilities each ≤ 20 kilowatts (kW). Since Tier II is behind the meter, the expected solar generation is embedded in the load forecast as a reduction to expected load.
- Tier III: Investment by the utility in 13 MW of solar capacity from facilities each >1 MW and less than 10 MW in size. Upon completion of Tiers I and II (to occur no later than

[3] One percent of the Company's South Carolina retail peak is equal to approximately 13 MW.

2021), the Company can directly invest in additional solar generation to complete Tier III.

In DEP-South Carolina, as part of the SC DER plan, the Company launched its first Shared Solar program. Often called "community solar," shared solar refers to both a solar facility and a billing structure in which multiple customers subscribe to and share in the economic benefits of the output of a single solar facility. The Company designed its initial SC DER shared solar program such that it would have strong appeal to residential and commercial customers who rent or lease their premise, to residential customers who reside in multifamily housing units or shaded housing, and to residential customers for whom the relatively high up-front costs of solar photovoltaic (PV) make net metering unattainable. The Company is evaluating the potential for a shared solar offer to North Carolina customers. Furthermore, the Company continues to study the potential for programs that support more load-centered rooftop solar PV installation in North Carolina.

DEP is also evaluating additional programs similar to the Green Source Rider in DEC as companies nationwide have demonstrated a desire for solar to support growing sustainability goals. For example, technology companies that often have data centers have signed around 1 GW of renewable energy PPAs nationally from 2015-June 2016.

Battery Storage and Wind

In addition to solar, the Company is assessing renewable technologies such as battery storage and wind. Battery storage costs are expected to decline significantly which may make it a viable option in the long run to support operational challenges caused by uncontrolled solar penetration. In the short run, battery storage is expected to be used primarily to support localized distribution based issues. For example, DEP is committed to the Western Carolinas Modernization Project (WCMP) where DEP will site at least 15 MW of solar and 5 MW of storage capacity in the DEP-Western Region to support the retirement of the two coal units at Asheville. The WCMP will be a great learning experience for the Company on how to effectively deploy more battery storage in the future to facilitate safe, reliable, and cost effective integration of renewable resources with the rest of the generation, transmission, and distribution systems.

Similar to solar, at the end of 2015, wind received a boost from the announcement of a multi-year extension of the wind energy Production Tax Credit (PTC). Investing in wind inside of DEP's footprint is unlikely in the short term in spite of the PTC. This is primarily due to a lack of suitable sites and permitting challenges, as well as less significant expected drops in capital costs compared to other renewable technologies like solar. As discussed in the NC REPS compliance plan however, additional opportunities may be pursued to transmit wind energy from out of state regions where wind is more prevalent and into the Carolinas.

Summary of Expected Renewable Resource Capacity Additions

The 2016 IRP incorporated three different renewable capacity forecasts: Low Case, Base Case, and High Case. Each of these cases includes renewable capacity required for compliance with NC REPS, non-compliance PURPA renewable purchases, as well as SC DER and other solar capacity associated with customer programs. The Company anticipates a diverse portfolio including solar, biomass, hydro, and other resources. Actual results could vary substantially depending on the uncertainties listed above as well as other potential changes to future legislative requirements, supportive tax policies, technology, and other market forces. The details of the forecasted capacity additions, including both nameplate and contribution to winter and summer peaks are summarized in Table 5-A below.

While solar doesn't normally reach its maximum output at the time of DEP's expected peak load in the summer, solar's contribution to summer peak load is large enough (44% of nameplate solar capacity) that it may push the time of summer peak (net of solar) from hour beginning 4:00 PM to 5:00 PM or later if solar penetration levels continue to increase. Note, however, that solar is unlikely to have a similar impact on the morning winter peak (net of solar) due to lower expected solar output in the morning hours (5% of nameplate solar capacity contribution).

Table 5-A DEP Base Case Total Renewables

DEP Base Renewables - Compliance + Non-Compliance										
	MW Nameplate			MW Contribution to Summer Peak				MW Contribution to Winter Peak		
	Solar	Biomass/ Hydro	Total	Solar	Biomass/ Hydro	Total		Solar	Biomass/ Hydro	Total
2017	1710	290	2000	752	290	1042	2016/2017	85	290	376
2018	1989	240	2229	875	240	1115	2017/2018	99	240	340
2019	2302	240	2543	1013	240	1253	2018/2019	115	240	355
2020	2560	236	2795	1126	236	1362	2019/2020	128	236	364
2021	2810	236	3046	1236	236	1472	2020/2021	140	236	376
2022	2969	172	3141	1306	172	1478	2021/2022	148	172	320
2023	3015	90	3105	1327	90	1416	2022/2023	151	90	240
2024	3050	90	3139	1342	90	1431	2023/2024	152	90	242
2025	3081	90	3171	1356	90	1445	2024/2025	154	90	244
2026	3112	90	3202	1369	90	1459	2025/2026	156	90	245
2027	3145	88	3233	1384	88	1472	2026/2027	157	88	245
2028	3178	85	3263	1398	85	1483	2027/2028	159	85	244
2029	3212	76	3288	1413	76	1489	2028/2029	161	76	237
2030	3244	76	3320	1428	76	1503	2029/2030	162	76	238
2031	3270	76	3346	1439	76	1515	2030/2031	163	76	239

* Solar includes 0.5% per year degradation

Given the significant volume and uncertainty around solar penetration, high and low solar portfolios were evaluated compared to the Base Case described above. The portfolios don’t envision a specific market condition, but rather the potential combined effect of a number of factors. For example, the high sensitivity could occur given events such as high carbon prices, lower solar capital costs, economical solar plus storage, continuation of renewal subsidies, and/or stronger renewable energy mandates. On the other hand, the low sensitivity may occur given events such as lower fuel prices for more traditional generation technologies, higher solar installation and interconnection costs, lower avoided costs, and/or less favorable PURPA terms. Tables 5-B and 5-C below provide the high and low solar nameplate capacity summaries as well as their corresponding expected contributions to summer and winter peaks.

Table 5-B DEP High Case Total Renewables

DEP High Renewables - Compliance + Non-Compliance										
	MW Nameplate			MW Contribution to Summer Peak				MW Contribution to Winter Peak		
	Solar	Biomass/ Hydro	Total	Solar	Biomass/ Hydro	Total		Solar	Biomass/ Hydro	Total
2017	1769	290	2059	779	290	1069	2016/2017	88	290	379
2018	2089	240	2329	919	240	1159	2017/2018	104	240	345
2019	2472	240	2712	1088	240	1328	2018/2019	124	240	364
2020	2797	236	3033	1231	236	1467	2019/2020	140	236	376
2021	3048	236	3284	1341	236	1577	2020/2021	152	236	388
2022	3384	172	3556	1489	172	1661	2021/2022	169	172	341
2023	3626	90	3715	1595	90	1685	2022/2023	181	90	271
2024	3817	90	3906	1679	90	1769	2023/2024	191	90	280
2025	3995	90	4084	1758	90	1847	2024/2025	200	90	289
2026	4175	90	4264	1837	90	1927	2025/2026	209	90	298
2027	4357	88	4445	1917	88	2005	2026/2027	218	88	306
2028	4542	85	4627	1998	85	2083	2027/2028	227	85	312
2029	4728	76	4804	2080	76	2156	2028/2029	236	76	312
2030	4911	76	4987	2161	76	2237	2029/2030	246	76	321
2031	5062	76	5138	2227	76	2303	2030/2031	253	76	329

* Solar includes 0.5% per year degradation

Table 5-C DEP Low Case Total Renewables

DEP Low Renewables - Compliance + Non-Compliance										
	MW Nameplate			MW Contribution to Summer Peak				MW Contribution to Winter Peak		
	Solar	Biomass/ Hydro	Total	Solar	Biomass/ Hydro	Total		Solar	Biomass/ Hydro	Total
2017	1710	290	2000	752	290	1042	2016/2017	85	290	376
2018	1782	240	2022	784	240	1024	2017/2018	89	240	329
2019	1873	240	2113	824	240	1064	2018/2019	94	240	334
2020	1947	236	2182	857	236	1092	2019/2020	97	236	333
2021	2018	236	2254	888	236	1124	2020/2021	101	236	337
2022	2086	172	2258	918	172	1090	2021/2022	104	172	276
2023	2151	90	2241	947	90	1036	2022/2023	108	90	197
2024	2213	90	2303	974	90	1063	2023/2024	111	90	200
2025	2271	90	2361	999	90	1089	2024/2025	114	90	203
2026	2330	90	2419	1025	90	1115	2025/2026	116	90	206
2027	2389	88	2477	1051	88	1139	2026/2027	119	88	207
2028	2449	85	2534	1077	85	1163	2027/2028	122	85	207
2029	2510	76	2586	1104	76	1180	2028/2029	125	76	201
2030	2569	76	2645	1130	76	1206	2029/2030	128	76	204
2031	2618	76	2694	1152	76	1228	2030/2031	131	76	207

* Solar includes 0.5% per year degradation

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 2016 IRP, the Company considered a diverse range of technology choices utilizing a variety of different fuels, including ultra-supercritical pulverized coal (USCPC) units with carbon capture and sequestration (CCS), integrated gasification combined cycle (IGCC) with CCS, CTs, CCs with inlet chillers and duct firing, Combined Heat and Power, reciprocating engines, and nuclear units. In addition, Duke Energy Progress considered renewable technologies such as wind, solar, battery storage and landfill gas in the screening analysis.

For the 2016 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.

Dispatchable (Summer Ratings)

- Base load – 782 MW Ultra-Supercritical Pulverized Coal with CCS
- Base load – 557 MW 2x1 IGCC with CCS
- Base load – 2 x 1,117 MW Nuclear Units (AP1000)
- Base load – 576 MW – 1x1x1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Base load – 1,160 MW – 2x2x1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Base load – 20 MW – Combined Heat & Power
- Peaking/Intermediate – 166 MW 4 x LM6000 Combustion Turbines

- Peaking/Intermediate – 201 MW 12 x Reciprocating Engine Plant
- Peaking/Intermediate – 870 MW 4 x 7FA.05 Combustion Turbines (CTs)
- Renewable – 2 MW / 8 MWh Li-ion Battery
- Renewable – 5 MW Landfill Gas

Non-Dispatchable

- Renewable – 150 MW Wind - On-Shore
- Renewable – 5 MW Solar PV

7. RESOURCE ADEQUACY

Background

Resource adequacy refers to the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Utilities require a margin of reserve generating capacity 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. The Company utilizes a reserve margin target in its IRP process to ensure resource adequacy. Reserve margin is defined as total resources minus peak demand, divided by peak demand. The reserve margin target is established based on probabilistic assessments as described below.

In 2012, the Company retained Astrape Consulting to conduct a resource adequacy study to determine the level of reserves needed to maintain adequate generation system reliability. Based on results of the 2012 Astrape analysis, the Company adopted a 14.5% minimum summer planning reserve margin for scheduling new resource additions.

In 2016, the Company again retained Astrape Consulting to conduct an update to the resource adequacy study performed in 2012. The updated study was warranted due to two primary factors. First, the extreme weather experienced in the service territory in recent winter periods was so impactful to the system that additional review with the inclusion of recent years' weather history was warranted. Second, since the last resource adequacy study the system has added, and projects to add, a large amount of resources that provide meaningful capacity benefits in the summer. From a peak reduction perspective, summer-oriented resources include summer load control programs, chiller additions to natural gas combined cycle units, and solar generation. Solar resources contribute approximately 44% of nameplate capacity at the time of the expected summer peak demand and only about 5% of nameplate capacity at the time of expected winter peak demand. The interconnection queue for solar facilities shows the potential to add significantly to the solar resources already incorporated on the system.

2016 Resource Adequacy Study Results

Astrape conducted an updated resource adequacy assessment in 2016 that incorporated the uncertainty of weather, economic load growth, unit availability, and the availability of transmission and generation capacity for emergency 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 reliability 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 shortage 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 increase, including the costs to customers for 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.

In the past, loss of load risk has typically been concentrated during the summer months and a summer reserve margin target provided adequate reserves in the summer and winter and was thus sufficient for ensuring resource adequacy. However, the incorporation of recent winter load data and the significant amount of solar penetration in the updated study, shows that the majority of loss of load risk is now heavily concentrated during the winter period. Since solar capacity contribution to peak is much greater in the summer compared to the winter, use of a summer reserve margin target will no longer ensure that adequate reserve levels are maintained in the winter. As a result, a winter planning reserve margin target is now needed to ensure that adequate resources are available throughout the year to meet customer demand.

Based on results of the 2016 resource adequacy assessment, the Company has adopted a 17% minimum winter reserve margin target for scheduling new resource additions. Astrape also recommends maintaining a 15% minimum summer reserve margin to ensure adequate reliability is maintained during the summer period. However, given the portfolio of existing and projected new resources, a 15% summer reserve margin will always be satisfied if a 17% winter reserve margin is maintained. The Company will continue to monitor its generation portfolio and other planning assumptions that can impact resource adequacy and initiate new studies as appropriate.

Adequacy of Projected Reserves

DEP's resource plan reflects winter reserve margins ranging from approximately 17% to 27% through the planning period. 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 17% winter target by 3% or more through the winter of 2018/19 primarily due to lower load growth resulting from a slightly slower economic forecast as shown in recent IRPs, as well as a reduction in the wholesale load forecast.

The IRP provides general guidance in the type and timing of resource additions. Since capacity is generally added in large blocks to take advantage of economies of scale, it should be noted that projected planning reserve margins in years immediately following new generation additions will often be somewhat higher than the minimum target. 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

As described in the previous chapter, DEP has added a winter planning reserve margin criteria to the IRP process. 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 17% minimum planning winter 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 five alternative portfolios as discussed later in this chapter and in Appendix A.

IRP Process

The following section summarizes the Data Input, Generation Alternative Screening, Portfolio Development and Detailed Analysis steps in the IRP process. A more detailed discussion of the IRP Process and development of the Base Case and additional portfolios is provided in Appendix A.

Data Inputs

The initial step in the IRP development process is one of input data refreshment and revision. For the 2016 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, DEP and DEC 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 utilized.

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

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

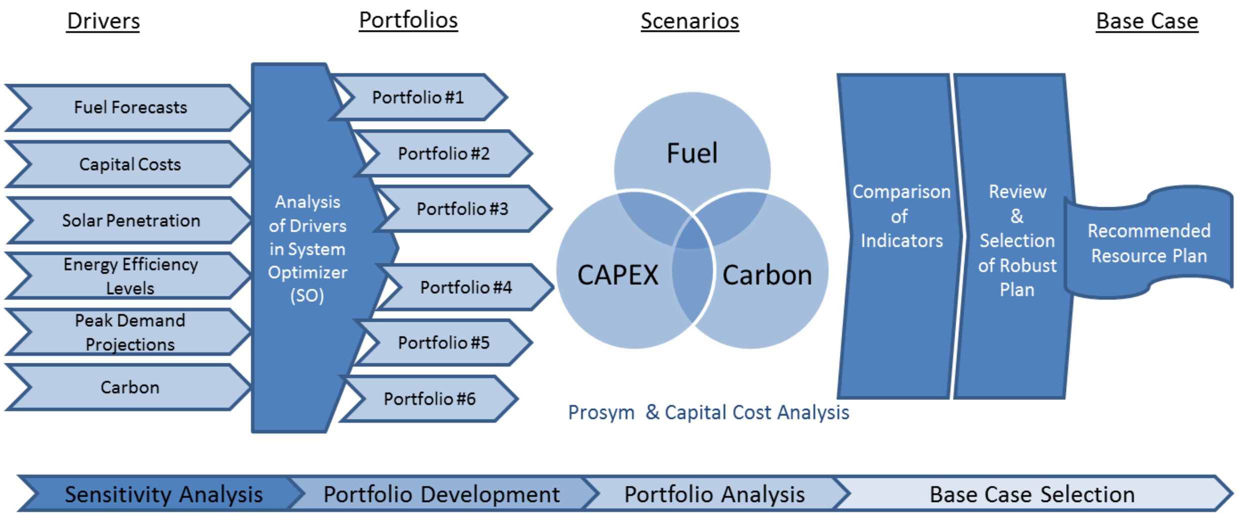
Generation Alternative Screening

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 to be both technically and economically viable are then passed to the detailed analysis process for further analysis.

Portfolio Development and Detailed Analysis

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

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



The Sensitivity Analysis and Portfolio Development phases rely upon the updated data inputs and results of the generation alternative screening process to derive resource portfolios or resource plans. The Sensitivity Analysis and Portfolio Development phases utilize an expansion planning model 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, possible expansion plan options for the DEP system are developed. These expansion plans are reviewed to determine if any overarching trends are present across the plans, and based on this analysis, specific portfolios are developed to represent these trends. Finally, the portfolios are analyzed using a capital cost model and an hourly production cost model (PROSYM) under various fuel price, capital cost and carbon scenarios to evaluate the robustness and economic value of each portfolio, and at this point, the Base Case portfolio is selected.

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 2016 IRP, six representative portfolios were identified through the Sensitivity Analysis and Portfolio Development steps. Four of the portfolios were developed under a Carbon Tax paradigm where varying levels of an intrastate CO_2 tax were applied to existing coal and gas units as envisioned in EPA's Clean Power Plan. These portfolios included a portfolio that was mainly centered around CT technology, a portfolio that was centered around CC technology, a portfolio with high renewable penetration, and a portfolio with high EE penetration.

The remaining two portfolios were developed under a System CO_2 Mass Cap that represented an alternative outcome of the CPP. In these portfolios total system CO_2 emissions were constrained starting in 2022 and declined until 2030, and total system emission were held flat from 2030 throughout the remaining planning horizon. One of these portfolios included base EE and base renewable assumptions, while the other portfolio included higher levels of EE and renewables. In general, both of these portfolios required relicensing or replacement of existing nuclear generation in both DEP and DEC, along with construction of the Lee Nuclear Plant in the late 2020s in DEC.

Portfolio Analysis & Base Case Selection

The six portfolios identified in the screening analysis were evaluated in more detail with an hourly production cost model under several scenarios. The four scenarios are summarized in Table 8-A and included sensitivities on fuel, carbon, and capital cost.

Table 8-A Scenarios for Portfolio Analysis

	Carbon Tax/No Carbon Tax Scenarios[1]	Fuel	CO_2	CAPEX
1	Current Trends	Base	CO_2 Tax	Base
2	Economic Recession	Low Fuel	No CO_2 Tax	Low
3	Economic Expansion	High Fuel	CO_2 Tax	High

[1]Run Portfolios 1 - 4 through each of these 3 scenarios

	System Mass Cap Scenarios[2]	Fuel	CO_2	CAPEX
4	Current Trends - CO_2 Mass Cap	Base	Mass Cap	Base

[2]Run Portfolios 5 - 6 through this single MC2 scenario

Portfolios 1 through 4 were analyzed under a current economic trend scenario (Scenario #1), an economic recession scenario (Scenario #2), and an economic expansion scenario (Scenario #3). Portfolios 5 & 6 were only evaluated under the Current Trends – System Mass Cap scenario (Scenario #4).

Under a cap on system carbon emissions, fuel price and capital cost will have little impact on the optimization of the system as the carbon output of the various generators will control dispatch to a greater extent than the fuel price.

Table 8-B lists the Portfolios that were developed under a Carbon Tax paradigm, along with their PVRR rankings under the three scenarios.

Table 8-B: Portfolios 1 – 4 PVRR Rankings

Portfolio	Scenario #1 (Current Trends)	Scenario #2 (Economic Recession)	Scenario #3 (Economic Expansion)
Portfolio #1 – **Base Case**	1	1	1
Portfolio #2 (High Renew)	4	4	4
Portfolio #3 (High EE)	2	2	2
Portfolio #4 (High CC)	3	3	3

In the three scenarios, Portfolio #1 (Base Case) was the lowest cost portfolio. The costs of Portfolios 2 & 3 were negatively impacted by expanding the amount of renewable resources beyond the NC REPS requirements and energy efficiency above the achievable potential. However, Portfolio #3 (High EE) had a PVRR that was nearly as low as Portfolio #1 when capital costs and fuel prices were increased in the Economic Expansion scenario. Portfolio #2 (High Renewables) had the lowest carbon footprint in each of the three scenarios evaluated; however, this Portfolio had the highest PVRR cost. The higher capital cost and fixed gas pipeline costs associated with combined cycles caused Portfolio #4 (High CC) to have a higher cost than Portfolio #1.

Future CO_2 legislation is still uncertain, and a system mass cap on carbon emissions is still a possibility. The short term build plan from Portfolio #1 (Base Case) would keep the Company on track if a System CO_2 Mass Cap were implemented. Additionally, Portfolio #1 was the least cost portfolio from a revenue requirements perspective.

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 #1 was selected as the Base Case under a Carbon Tax paradigm in the 2016 IRP.

Finally, Portfolios 5 and 6 were evaluated under the Current Trends scenario with a System CO_2 Mass Cap carbon constraint. Under the Mass Cap carbon paradigm, the high EE and high renewable combination led to a significantly higher PVRR versus the Base Case. The \$1.7B savings in system production costs was not enough to overcome the \$2.5B capital cost of the high EE/high renewable portfolio. Given the PVRR delta between the two cases, and the uncertainty of achieving the high

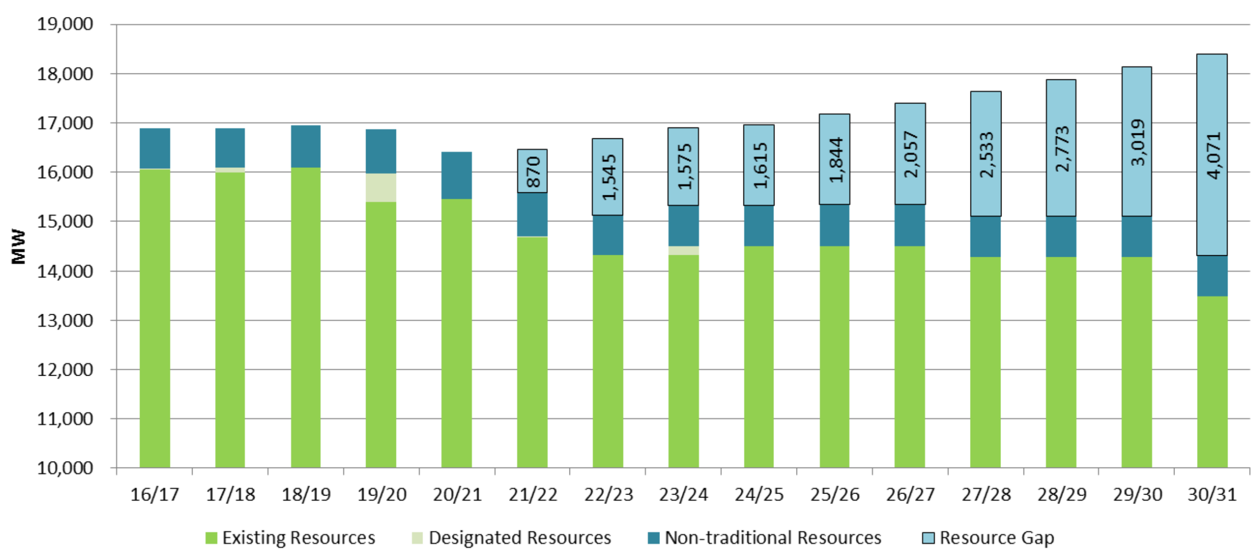
EE targets, Portfolio #5 was selected to represent the base case under a System Mass Cap carbon plan.

Base Case

The Base Case was selected based upon the evaluation of the portfolios in the Carbon Tax paradigm. The Base Case was developed utilizing consistent assumptions and analytic methods between DEP and DEC, where appropriate. This case does not take into account the sharing of capacity between DEP and DEC. However, the Base Case incorporates the JDA between DEP and DEC, which represents a non-firm energy only commitment between the Companies. A Joint Planning Case that begins to explore the potential for DEP and DEC 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 2022. As a result, the resource plan analyses described above have determined the most robust plan to meet this resource gap.

Chart 8-A DEP Base Case Load Resource Balance (Winter)



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

Year	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24
Resource Need	0	0	0	0	0	870	1,545	1,575
Year	24/25	25/26	26/27	27/28	28/29	29/30	30/31	
Resource Need	1,615	1,844	2,057	2,533	2,773	3,019	4,071	

Tables 8-C and 8-D present the Load, Capacity and Reserves (LCR) tables for the Base Case analysis that was completed for DEP's 2016 IRP.

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

Winter Projections of Load, Capacity, and Reserves
for Duke Energy Progress 2016 Annual Plan

	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
Load Forecast															
1 Duke System Peak	13,190	13,336	13,527	13,653	13,872	14,085	14,296	14,511	14,721	14,942	15,146	15,365	15,573	15,787	16,010
2 Firm Sale	150	150	150	150	150	150	150	150	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(31)	(59)	(85)	(110)	(144)	(166)	(189)	(210)	(232)	(253)	(272)	(284)	(289)	(289)	(291)
4 Adjusted Duke System Peak	**13,308**	**13,427**	**13,592**	**13,692**	**13,878**	**14,068**	**14,257**	**14,450**	**14,488**	**14,689**	**14,874**	**15,082**	**15,283**	**15,497**	**15,719**
Existing and Designated Resources															
5 Generating Capacity	13,972	13,852	13,876	13,890	13,561	13,561	13,567	13,567	13,757	13,757	13,757	13,757	13,525	13,525	13,525
6 Designated Additions / Uprates	8	100	14	572	0	6	0	190	0	0	0	0	0	0	0
7 Retirements / Derates	(128)	(76)	0	(901)	0	0	0	0	0	0	0	(232)	0	0	(797)
8 Cumulative Generating Capacity	**13,852**	**13,876**	**13,890**	**13,561**	**13,561**	**13,567**	**13,567**	**13,757**	**13,757**	**13,757**	**13,757**	**13,525**	**13,525**	**13,525**	**12,728**
Purchase Contracts															
9 Cumulative Purchase Contracts	**2,323**	**2,329**	**2,337**	**2,029**	**2,033**	**1,211**	**834**	**834**	**834**	**833**	**833**	**830**	**830**	**830**	**829**
Non-Compliance Renewable Purchases	109	115	123	128	134	82	82	82	82	81	81	81	81	80	80
Non-Renewables Purchases	2,214	2,214	2,214	1,901	1,899	1,129	752	752	752	752	752	749	749	749	749
Undesignated Future Resources															
10 Nuclear															
11 Combined Cycle						1,221									
12 Combustion Turbine							468			468		468	468		1,404
Renewables															
13 Cumulative Renewables Capacity	267	224	233	236	242	238	158	160	162	164	164	163	156	158	159
14 Combined Heat & Power	0	0	22	22	22	0	0	0	0	0	0	0	0	0	0
15 Cumulative Production Capacity	**16,442**	**16,430**	**16,481**	**15,869**	**15,902**	**16,302**	**16,314**	**16,505**	**16,507**	**16,976**	**16,977**	**17,208**	**17,669**	**17,670**	**18,279**
Demand Side Management (DSM)															
16 Cumulative DSM Capacity	**445**	**462**	**477**	**490**	**503**	**508**	**512**	**515**	**519**	**522**	**526**	**530**	**533**	**535**	**538**
17 Cumulative Capacity w/ DSM	**16,886**	**16,892**	**16,958**	**16,359**	**16,404**	**16,811**	**16,825**	**17,021**	**17,026**	**17,499**	**17,502**	**17,738**	**18,201**	**18,206**	**18,817**
Reserves w/ DSM															
18 Generating Reserves	3,578	3,464	3,366	2,667	2,526	2,742	2,568	2,570	2,537	2,810	2,629	2,656	2,918	2,708	3,098
19 % Reserve Margin	**27%**	**26%**	**25%**	**19%**	**18%**	**19%**	**18%**	**18%**	**18%**	**19%**	**18%**	**18%**	**19%**	**17%**	**20%**

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

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Progress 2016 Annual Plan

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Load Forecast															
1 Duke System Peak	13,185	13,327	13,512	13,602	13,786	13,969	14,164	14,355	14,550	14,764	14,954	15,160	15,347	15,538	15,741
2 Firm Sale	150	150	150	150	150	150	150	150	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(58)	(93)	(128)	(158)	(187)	(216)	(245)	(272)	(301)	(329)	(353)	(368)	(374)	(374)	(376)
4 Adjusted Duke System Peak	**13,277**	**13,384**	**13,535**	**13,594**	**13,749**	**13,903**	**14,069**	**14,233**	**14,249**	**14,435**	**14,601**	**14,792**	**14,973**	**15,164**	**15,365**
Existing and Designated Resources															
5 Generating Capacity	12,873	12,805	12,812	12,820	12,531	12,535	12,535	12,537	12,698	12,698	12,698	12,518	12,518	12,518	11,777
6 Designated Additions / Uprates	88	7	8	495	4	0	2	161	0	0	0	0	0	0	0
7 Retirements / Derates	(156)	0	0	(784)	0	0	0	0	0	0	(180)	0	0	(741)	0
8 Cumulative Generating Capacity	**12,805**	**12,812**	**12,820**	**12,531**	**12,535**	**12,535**	**12,537**	**12,698**	**12,698**	**12,698**	**12,518**	**12,518**	**12,518**	**11,777**	**11,777**
Purchase Contracts															
9 Cumulative Purchase Contracts	**2,416**	**2,471**	**2,367**	**2,271**	**1,613**	**1,262**	**1,260**	**1,258**	**1,256**	**1,254**	**1,252**	**1,247**	**1,245**	**1,243**	**1,241**
Non-Compliance Renewable Purchases	341	396	460	509	558	535	533	531	528	526	524	522	520	518	517
Non-Renewables Purchases	2,075	2,075	1,907	1,762	1,054	727	727	727	727	727	727	724	724	724	724
Undesignated Future Resources															
10 Nuclear															
11 Combined Cycle						1,123									
12 Combustion Turbine							435			435		435	435		1,305
Renewables															
13 Cumulative Renewables Capacity	701	720	794	852	914	943	884	901	917	933	947	961	969	985	998
14 Combined Heat & Power	0	0	20	20	20	0	0	0	0	0	0	0	0	0	0
15 Cumulative Production Capacity	**15,922**	**16,002**	**16,000**	**15,695**	**15,121**	**15,923**	**16,298**	**16,475**	**16,488**	**16,937**	**16,770**	**17,214**	**17,654**	**16,928**	**18,244**
Demand Side Management (DSM)															
16 Cumulative DSM Capacity	**869**	**913**	**951**	**983**	**1,006**	**1,016**	**1,019**	**1,023**	**1,026**	**1,030**	**1,033**	**1,037**	**1,040**	**1,043**	**1,047**
17 Cumulative Capacity w/ DSM	**16,792**	**16,915**	**16,951**	**16,678**	**16,128**	**16,939**	**17,318**	**17,497**	**17,515**	**17,967**	**17,803**	**18,250**	**18,694**	**17,971**	**19,291**
Reserves w/ DSM															
18 Generating Reserves	3,514	3,531	3,416	3,084	2,379	3,036	3,248	3,264	3,266	3,532	3,202	3,458	3,721	2,807	3,926
19 % Reserve Margin	**26%**	**26%**	**25%**	**23%**	**17%**	**22%**	**23%**	**23%**	**23%**	**24%**	**22%**	**23%**	**25%**	**19%**	**26%**

DEP - Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Winter Projections of Load, Capacity, and Reserves table. All values are MW (winter ratings) 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 firm sales and cumulative energy efficiency.

5. Existing generating capacity reflecting designated additions, planned uprates, retirements and derates as of January 1, 2016.

   Includes total unit capacity of jointly owned units.

6. Capacity Additions include:

   Planned nuclear uprates totaling 44 MW in the 2017-2024 timeframe.

   100 MW Sutton Blackstart combustion turbine addition in 2017.

   560 MW Asheville combined cycle addition in November 2019.

   Potential 186 MW Asheville combustion turbine addition in 2024.

7. Planned Retirements include:

   384 MW Asheville Coal Units 1-2 in November 2019.

   76 MW Sutton CT Units 1, 2A and 2B in 2017.

   645 MW Darlington CT Units 1-10 by 2020.

   232 MW Blewett CT Units 1-4 and Weatherspoon CT units 1-4 in 2027.

   Planning assumptions for nuclear stations assume retirement at the end of their current license extension.

   797 MW Robinson 2 in 2030.

DEP - Assumptions of Load, Capacity, and Reserves Table (cont.)

All retirement dates are subject to review on an ongoing basis. Dates used in the 2016 IRP are for planning purposes only, unless already planned for retirement.

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 QF purchases.

   Renewables in these line items are not used for NC REPS compliance.

10. New nuclear resources 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 the next 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 the next year.

    Addition of 1,221 MW of combined cycle capacity online December 2021.

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 the next year.

    Addition of 468 MW of combustion turbine capacity in online in December of 2022, 2025, 2027, and 2028.

DEP - Assumptions of Load, Capacity, and Reserves Table (cont.)

Addition of 1,404 MW of combustion turbine capacity online December 2030.

13. Resources to comply with NC REPS along with solar customer product offerings such as Green Source and SC DER. Solar resources reflect 5% of nameplate capacity contribution at the time of winter peak demand and 44% of nameplate capacity contribution at the time of summer peak demand.

14. New 21.7 MW (winter) combined heat and power units included in 2019, 2020 and 2021. The 2016 IRP represents increased CHP resources as compared to the 2015 IRP.

15. Sum of lines 8 through 14.

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

17. Sum of lines 15 and 16.

18. The difference between lines 17 and 4.

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

    Line 18 divided by Line 4.

    Minimum target planning reserve margin is 17%.

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

Table 8-E DEP Base Case

Duke Energy Progress Resource Plan (1)
Base Case - Winter

Year	Resource			MW		
2017	Nuclear Uprates			8		
2018	Sutton Blackstart CT			100		
2019	Nuclear Uprates	CHP		14	22	
2020	Nuclear Uprates	Asheville CC	CHP	12	560	22
2021	CHP			22		
2022	Nuclear Uprates	New CC		6	1221	
2023	New CT			468		
2024	Nuclear Uprates	Potential Asheville CT		4	186	
2025						
2026	New CT			468		
2027						
2028	New CT			468		
2029	New CT			468		
2030						
2031	New CT			1404		

Notes: (1) Table includes both designated and undesignated capacity additions
Future additions of renewables, EE and DSM not included

Additionally, a summary of the above table by fuel type is represented below in Table 8-F.

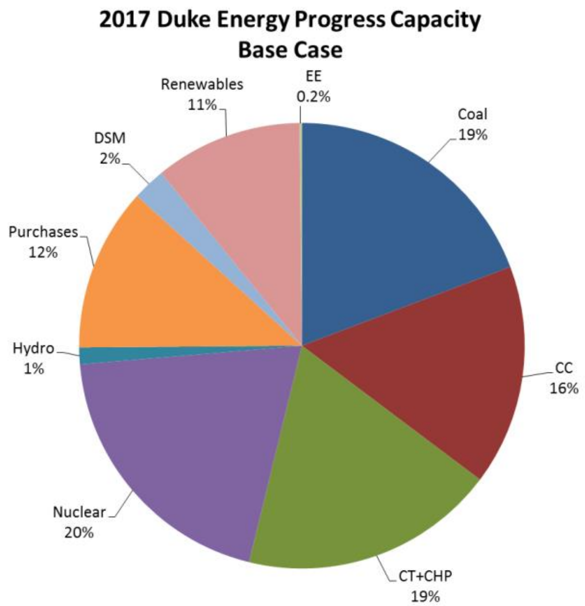
Table 8-F DEP Base Case Winter Resources by Fuel Type

DEP Base Case Resources
Cumulative Winter Totals - 2017 - 2031

Nuclear	44
CC	1781
CT	3562
CHP	66
Total	5453

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 2031, the Base Case projects that DEP will have a smaller reliance on coal, nuclear and external purchases and a higher reliance on gas-fired resources, renewable resources and EE as compared to the current state. It should be noted that the Company's Base Case resources depicted in Chart 8-B below reflect a significant amount of solar capacity with nameplate solar growing from 1,710 MW in 2017 to 3,270 MW by 2031. However, given that solar resources only contribute 5% of nameplate capacity at the time of the Company's winter peak, solar capacity contribution to winter peak only grows from 85 MW in 2017 to 163 MW by 2031.

Chart 8-B Duke Energy Progress Capacity by Fuel Type – Base Case[4]



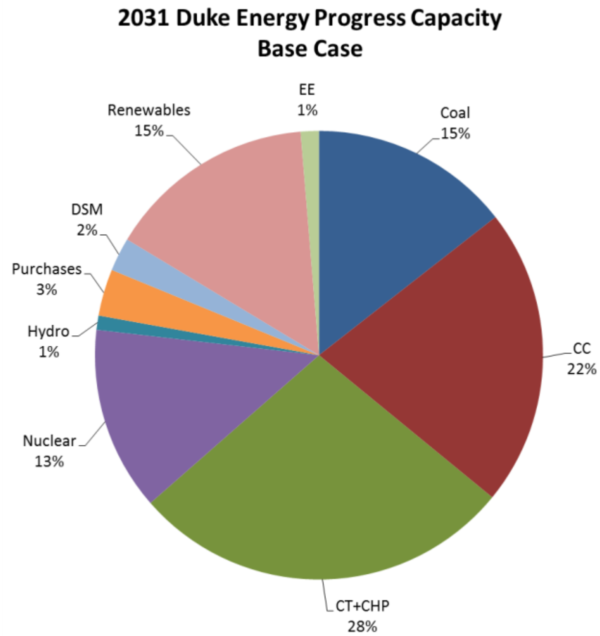
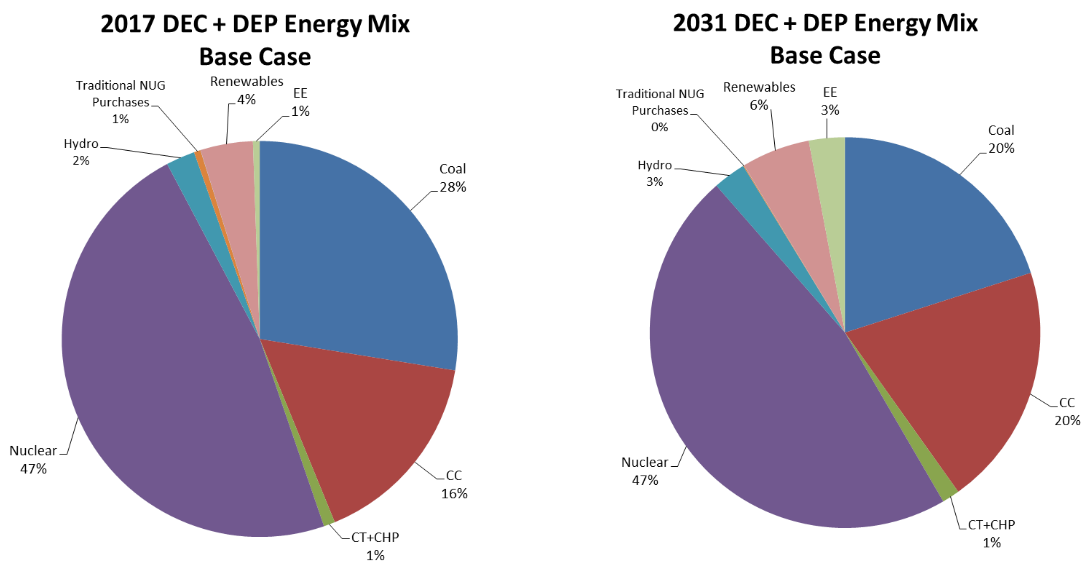


Chart 8-C represents the energy of the DEP and DEC Base Cases by fuel type. These energy charts represent both the DEP and DEC base cases. Due to the joint dispatch agreement (JDA), it is prudent to combine the energy of both utilities to develop a meaningful base case energy chart. From 2017 to 2031, the chart shows that nuclear resources will continue to serve almost half of DEC and DEP energy needs, a reduction in the energy served by coal, and an increase in energy served by natural gas, renewables and EE.

[4] Capacity based on winter ratings (renewables based on nameplate)

Chart 8-C DEP and DEC Energy by Fuel Type – Base Case



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 2016 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.

System Carbon Mass Cap Case

The System Carbon Mass Cap Case assumes that total system CO_2 emissions are constrained starting in 2022 and decline until 2030, and total system emission are held flat from 2030 throughout the remaining planning horizon. In order to hold system emissions flat, new nuclear generation, along with re-licensing or replacement of existing nuclear generation, is required in the early 2030s. To this point, additional new nuclear generation is required between the retirement of Robinson Nuclear Plant in 2030 and Brunswick 2 Nuclear Plant in 2035. Additionally, incremental solar generation begins to be economically selected (without inclusion of integration costs) just beyond the planning horizon shown in Table 8-G. It should be noted that the expansion planning model does not incorporate incremental solar integration costs when selecting resources, however these costs are added later when calculating the total PVRR of the resource plan.[5]

[5] Solar integration costs represented in the Duke Energy Photovoltaic Integration Study published by Pacific Northwest National Lab in March 2014.

Table 8-G DEP System Carbon Mass Cap Case

Duke Energy Progress Resource Plan (1) System Mass Cap - Winter						
Year	**Resource**			**MW**		
2017	Nuclear Uprates			8		
2018	Sutton Blackstart CT			100		
2019	Nuclear Uprates	CHP		14	22	
2020	Nuclear Uprates	Asheville CC	CHP	12	560	22
2021	CHP			22		
2022	Nuclear Uprates	New CC		6	1221	
2023	New CT			468		
2024	Nuclear Uprates	Potential Asheville CT		4	186	
2025						
2026	New CT			468		
2027						
2028	New CT			468		
2029	New CT			468		
2030						
2031	New CC			1221		

Notes: (1) Table includes both designated and undesignated capacity additions
Future additions of renewables, EE and DSM not included

Additionally, a summary of the above table by fuel type is represented below in Table 8-H.

Table 8-H DEP System Carbon Mass Cap Case Winter Resources by Fuel Type

DEP System Mass Cap Resources Cumulative Winter Totals - 2017 - 2031	
Nuclear	44
CC	3002
CT	2158
CHP	66
Total	5270

A detailed discussion of the assumptions, inputs and analytics used in the development of the System Mass Cap Case is contained in Appendix A. As previously noted, the further out in time planned additions or retirements are within the 2016 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 DEP and DEC 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 DEP and DEC with the understanding that the actual execution of capacity sharing would require separate regulatory proceedings and approvals.

Table 8-I below represents the annual non-renewable incremental additions reflected in the combined DEP and DEC winter Base Cases as compared to the Joint Planning Case. The plan contains the undesignated additions for DEP and DEC over the planning horizon. As presented in Table 8-I, the Joint Planning Case allows for the delay of several blocks of CT resources through the 15-year study period.

Table 8-I Joint Planning Case

DEC and DEP Combined Resource Plan (1)
Base Case - Winter

Year	Resource		MW	
2017				
2018				
2019				
2020				
2021				
2022	New CC		1221	
2023	New CC	New CT	1221	468
2024				
2025	New CT		468	
2026	New CT		468	
2027	New Nuclear		1117	
2028	New CT		468	
2029	New Nuclear	New CT	1117	468
2030				
2031	New CT		1404	

Notes: (1) Table only includes undesignated capacity additions.

Delay & Combine (2023 New CT and 2025 New CT → 2026)
Delay (2026 New CT → 2028)
Delay & Combine (2028 New CT and 2029 New CT → 2031)
Beyond Study Period (2031 New CT)

DEC and DEP Joint Planning Resource Plan (1)
Base Case - Winter

Year	Resource	MW
2017		
2018		
2019		
2020		
2021		
2022	New CC	1221
2023	New CC	1221
2024		
2025		
2026	New CT	936
2027	New Nuclear	1117
2028	New CT	468
2029	New Nuclear	1117
2030		
2031	New CT	1872

A comparison of both the DEP and DEC Combined Base Case and Joint Planning Base Case by fuel type is represented below in Table 8-J.

Table 8-J DEC and DEP Base Case and Joint Planning Case Comparison by Fuel Type

DEP and DEC Combined Base Case Resources

Cumulative Winter Totals - 2017 - 2031

Nuclear	2234
CC	2442
CT	3744
Total	8420

DEP and DEC Joint Base Case Resources

Cumulative Winter Totals - 2017 - 2031

Nuclear	2234
CC	2442
CT	3276
Total	7952

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 Planning to Include Consideration of Winter Peaks

As the Company looks forward, the planning focus will include consideration of winter peak demand based upon resource adequacy study results. As additional summer-oriented resources such as solar are added to both the DEP and DEC systems, it will be important to maintain a focus on the impacts of these resources to the winter peak and the operational requirements of the system.

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 collaborative work to develop and implement additional cost-effective EE and DSM products and services.

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

- Continue to seek additional DSM programs that will specifically benefit during winter peak situations.

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 regardless of the need for such energy. This level of solar being put to the DEP grid presents certain integration challenges to the generation portfolio and T&D grid as referenced in Chapter 5.

In 2015, DEP received approval for SC DER which includes a portfolio of initiatives designed to increase the capacity of renewable generation located in South Carolina's service area. The program contains three tiers; each is equivalent to 1% of the Company's estimated average South Carolina retail peak demand (or 13 MW of nameplate solar capacity). The first tier of SC DER is comprised of a combination of utility scale PPA's and ~1 MW shared solar facilities. The second tier of SC DER is met via behind the meter net rooftop solar for residential, commercial, and industrial customers. Since tier 2 is behind the meter, the expected solar generation is embedded in the load forecast as a reduction to expected load. Upon completion of tiers 1 and 2 (to occur no later than 2021), the legislation calls for the utility to directly invest in additional solar generation to complete tier 3 which DEP contemplates doing in 2019.

DEP continues to evaluate market options for renewable generation and procure capacity, as appropriate. PPAs have been signed with developers of solar PV and landfill gas. Also, REC purchase agreements have been executed for purchases of unbundled RECs from wind, solar PV, solar thermal and hydroelectric facilities. Additionally, shared solar programs and utility-owned solar continue to be considered.

<u>Addition of Clean Natural Gas Resources:</u>

- 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 (76 MW/61 MW (winter/summer)) are planned for retirement in 2017. A Certificate of Public Convenience and Necessity (CPCN) has been received for the units to be replaced with two LM6000 CT units expected online June 30, 2017.

- Take actions to ensure capacity needs beginning in 2022 are met. In addition to seeking to meet the Company's EE and DSM goals, meeting the Company's NC REPS requirements and SC DER projections actions to secure additional capacity may include purchased power or Company-owned generation. he 2016 IRP projects that the best resource to meet this demand is a combined cycle unit.

Western Carolinas Modernization Plan (WCMP)

The Western Carolinas Modernization Project allows for the early retirement of the Asheville Plant coal-fired units. The generation will be replaced with:

- Two new 280-megawatt combined cycle natural gas-fueled units.
- One contingent natural gas-fueled 186-megawatt simple cycle combustion turbine unit in 2023 timeframe subject to potential deferral or elimination as subsequently discussed.
- New solar generation at the Asheville plant site.

Additionally, Duke Energy Progress is committed to partnering with the community and elected leaders to reduce energy use by:

- Providing increased promotion of and access to new and existing EE/DSM programs.
- Making deliberate investment in distributed energy resources, including at least 15 megawatts of solar energy and at least 5 megawatts of energy storage.
- Delivering products and services customers value and help them connect with the role they play in this important work, through active community engagement.

The goal of this work is twofold:

1. To transition western North Carolina to a cleaner, smarter and more reliable energy future.
2. To delay or avoid the construction of the contingent combustion turbine.

This is significant work and success requires dedicated leadership and commitment. A partnership between Duke Energy Progress, Buncombe County, and the City of Asheville has been formed to develop innovative energy solutions to meet the area's growing energy needs and avoid the construction of the contingent combustion turbine. If successful, this collaboration could present an opportunity to create a replicable model for other communities and utilities to work together to build a smarter and cleaner energy future.

The cornerstone of this partnership was created by joint resolution between the City of Asheville and Buncombe County, fully endorsed by Duke Energy, to co-convene the Energy Innovation Task Force (EITF). Members of the EITF represent a wide array of community interests with one key attribute in common – a desire for a smarter, cleaner and more reliable energy future.

To jumpstart the EITF, task force leaders, including Duke Energy, participated in Rocky Mountain

Institute's (RMI) third annual eLab Accelerator in April 2016. Together, they created an initial work plan, milestones and immediate next steps.

Since eLab Accelerator, the EITF has convened and is rapidly moving forward to create a longer-term work plan in early 2017. The plan is expected to leverage utility expertise, programs, and investments; city and county resources; actions by EITF member constituencies; the outreach and engagement capacity of community groups; and capabilities and knowledge of national experts.

This work has become a foundation for community collaboration and successful implementation of the Western Carolinas Modernization Project.

Continued Focus on Environmental Compliance and Wholesale:

- Retire older coal generation. As of December 2013, all of DEP's older, un-scrubbed coal units have been retired. DEP has retired 1,700 MW/1,600 MW (winter/summer) of older coal units in total since 2011.[6]

- Retire older CT generation. As of December 2013, DEP has retired approximately 250 MW/200 MW (winter/summer) of older CT generation. The Company is evaluating the condition and economic viability of the older CTs. In doing so, DEP is preparing for the retirement of additional older CT unit in the near future. Darlington Unit 11 was retired in November 2015. Sutton Units 1, 2A and 2B are expected to retire by 2017 while Darlington Units 1-10 are expected to retire by 2020.

- Continue to investigate the future environmental control requirements and resulting operational impacts associated with existing and potential environmental regulations such as EPA's Clean Power Plan (Section 111d of Clean Air Act regulating CO_2 from existing power plants), Mercury Air Toxics Standard (MATS), the Coal Combustion Residuals (CCR) rule, the Cross State Air Pollution Rule (CSAPR) and the new Ozone National Ambient Air Quality Standard (NAAQS).

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

[6] The ultimate timing of unit retirements can be influenced by factors changing the economics of continued unit operations. Such factors include changes in relative fuel prices, operations and maintenance costs and the costs associated with compliance of evolving environmental regulations. As such, unit retirement schedules are expected change over time as market conditions change.

- 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 2016 IRP is shown in Table 9-A below. Capacity retirements and additions are presented as incremental values in the year in which the change impacts the winter peak. 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(1)						
			Compliance Renewable Resources (Cumulative Nameplate MW)			
Year	Retirements(2)	Additions	Solar (3)	Biomass/Hydro	EE	DSM (4)
2017		8 MW Nuc Uprate	1114	211	31	445
2018	76 MW Sutton 1, 2A, 2B	100 MW Sutton CT Repl	1270	161	59	462
2019		14 MW Nuc Uprate	1438	161	85	477
2020	384 MW Asheville 1-2 645 MW Darlington CT	560 MW Asheville CC 12 MW Nuc Uprate	1582	156	110	490
2021			1721	156	144	503

Notes:

(1) Capacities shown in winter ratings unless otherwise noted.

(2) Darlington Units 1-10 assume to retire March 2020. Darlington 4 & 6 are currently offline and are represented as a derate through 2020 until retirement.

(3) Capacity is shown in nameplate ratings. For planning purposes, solar has a 5% contribution to winter peak.

(4) Includes impacts of grid modernization.

DEP Request for Proposal (RFP) Activity

<u>Supply-Side</u>

No supply-side RFPs have been issued since the filing of DEP's 2015 IRP.

<u>Renewable Energy</u>

Duke Energy Distributed Energy Resource Solar RFP – South Carolina

Shared Solar Program RFP

A Shared Solar Program RFP was released on August 20, 2015, to solicit for up to 5 MW_{AC} (4 MW_{AC} in DEC/1 MW_{AC} in DEP) of solar PV facilities that would provide power and associated energy certificates within the DEP and DEC service territories in the state of South Carolina. Executed contracts in response to this RFP will be utilized to comply with the Duke Energy's "Shared Solar Program" under the South Carolina Distributed Energy Resource Program Act.

The RFP's interest was in solar PPAs and turnkey asset purchase proposals with a nameplate capacity sized > 250 kilowatts ($kW_{AC)}$ but no greater than 1 MW_{AC}. Proposals must be directly connected to the DEP or DEC transmission or distribution system in South Carolina. Projects must be in-service and capable of delivering fully rated output by December 31, 2016. PPA contract durations shall be a 10 year term.

Respondents were notified, February 22, 2016 of their proposal status and if they had been selected as a proposal of interest.

Proposals of interest were allowed to refresh bid pricing following the completion of DEP/DEC estimated interconnection costs. Proposals of interest are currently in varying stages of negotiations and contract execution.

Utility Scale Solar Program RFP

A Utility Scale Program RFP was released on August 20, 2015, to solicit 40 MW_{AC} in DEC and 13 MW_{AC} in DEP of solar PV facilities that would provide power and associated renewable energy certificates within the DEP and DEC service territories in South Carolina. Executed contracts in response to this RFP will be utilized to comply with the Duke Energy's "Utility Solar Program" under the South Carolina Distributed Energy Resource Program Act.

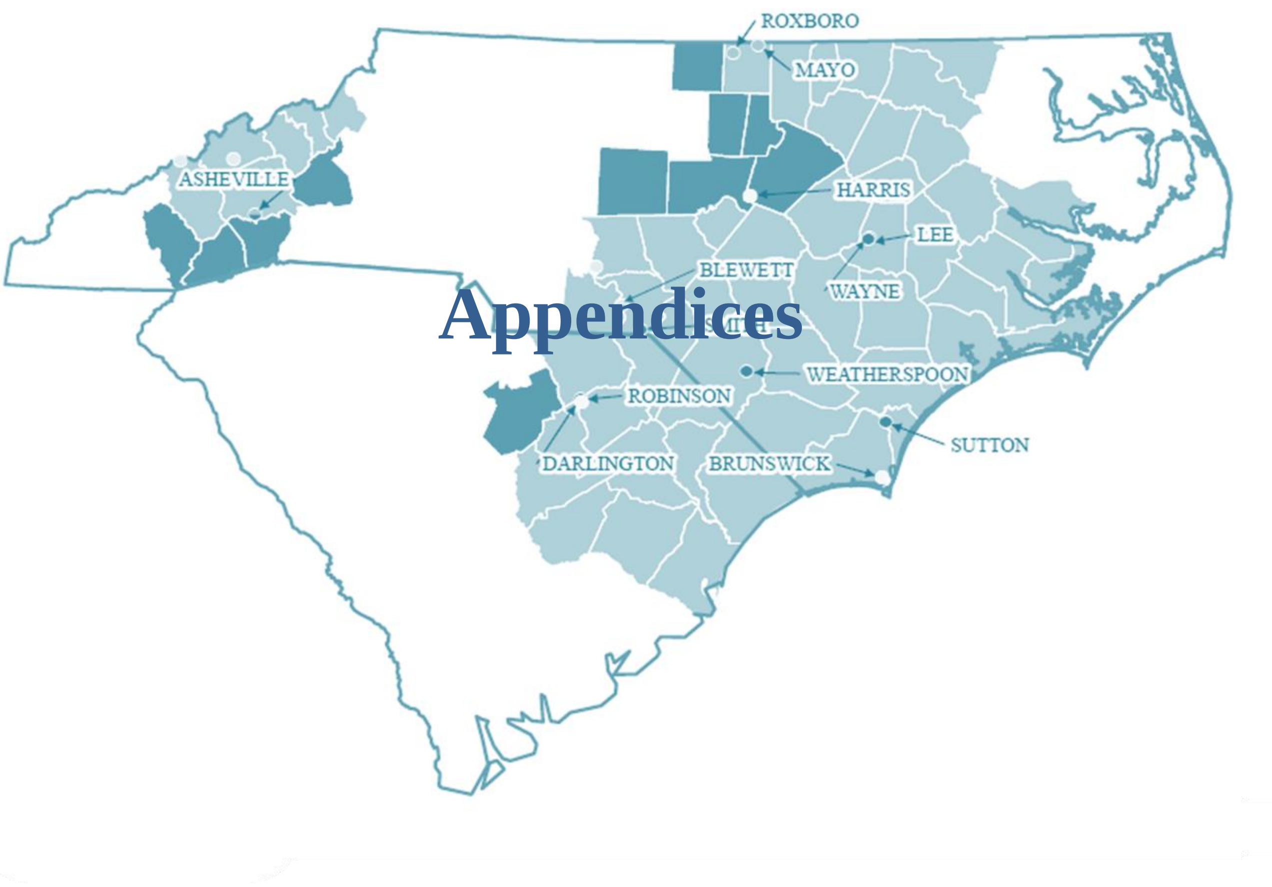
The RFP's interest was in solar PPAs and Turnkey asset purchase proposals with a nameplate capacity sized > 1 MW_{AC} and up to 10 MW_{AC}. Proposals must be directly connected to the DEP or DEC transmission or distribution system in South Carolina. Projects must be in-service and capable of delivering fully rated output by December 31, 2016. PPA contract durations shall be a 15 year term.

Respondents were notified, February 22, 2016 of their proposal status and if they had been selected as a proposal of interest.

Proposals of interest were allowed to refresh bid pricing following the completion of DEP/DEC estimated interconnection costs.

Proposals of interest are currently in varying stages of negotiations and contract execution.

Appendices


ROXBORO
MAYO
ASHEVILLE
HARRIS
LEE
BLEWETT
WAYNE
WEATHERSPOON
ROBINSON
SUTTON
DARLINGTON
BRUNSWICK

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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 under several scenarios that varied fuel prices, capital costs, and CO_2 constraints. These portfolios were analyzed using a least cost analysis to determine the Base Case for the 2016 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. Resource capacities discussed in this appendix reflect winter ratings and new resource additions are assumed online in January of the year indicated unless otherwise noted.

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 over various scenarios

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. Post-2020 consideration was also given to increased energy prices associated with a carbon constrained future.
- 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 2016 resource plan:

- Peak Demand and Energy Growth - The growth in winter customer peak demand including the impacts of energy efficiency averaged 1.3% from 2017 through 2031. The forecasted compound annual growth rate for energy consumption is 0.9% after the impacts of energy efficiency programs are included.
- Generation
    - Nuclear units uprates totaling 44 MW by 2024 at Brunswick and Harris plants.
    - Completion of the 100 MW Sutton LM 6000 CT (two units) in June 2017.
    - Completion of the 560 MW Asheville CC (two units) in November 2019.
    - Completion of the potential 186 MW Asheville CT in 2024, dependent upon success of EE initiatives.
- Retirements
    - Asheville Coal Units 1 & 2 located in Arden, NC, totaling 384 MW by 2020
    - Sutton CT Units 1, 2A and 2B, located in Wilmington, NC, totaling 76 MW in June 2017
    - Darlington CT Units 1 - 10, located in Darlington County, SC, totaling 645 MW by 2020
    - Blewett CT Units 1 – 4, located in Lilesville, NC, totaling 68 MW by 2027
    - Weatherspoon CT Units 1 – 4, located in Lumberton, NC, totaling 164 MW by 2027
    - Robinson 2 Nuclear Plant located in Hartsville, SC totaling 797 MW by June 2030

- Reserve Margin - A 17% minimum winter 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 (winter ratings):

- Baseload – 2 x 1,117 MW Nuclear units (AP1000)
- Baseload – 1,221 MW – 2 x 1 Advanced Combined Cycle (Duct Fired)
- Baseload – 22 MW – Combined heat and power
- Peaking/Intermediate – 468 MW – 2 x 7FA.05 CTs
    - (Based upon the cost to construct 4 units, available for brownfield sites only)
- Peaking/Intermediate – 936 MW – 4 x 7FA.05 CTs
- Renewable – 5 MW – Solar PV

Energy Efficiency and Demand-Side Management

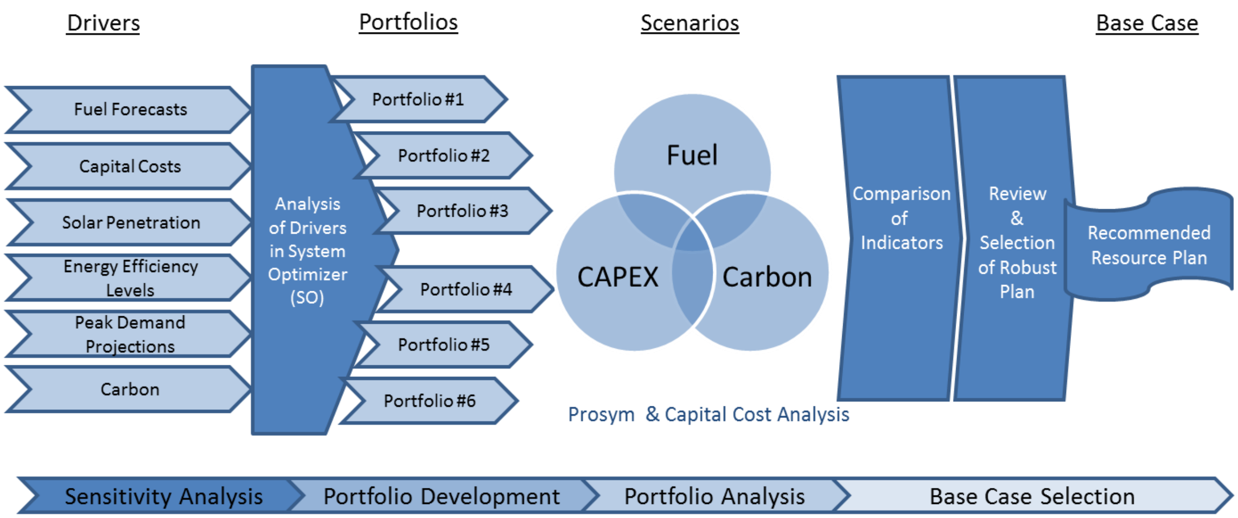
EE and DSM programs continue to be an important part of Duke Energy Progress' system mix. The Company considered both EE and DSM programs in the IRP analysis. As described in Appendix D, EE and DSM measures are compared to generation alternatives to identify cost-effective EE and DSM programs.

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

3. Develop Portfolio Configurations

Once the load and generation balance was assessed, and resource options were screened, the portfolios and scenarios were developed, and the preferred base cases were selected, based on the following simplified diagram.

Figure A-1: Simplified Process Flow Diagram for Development and Selection of Base Case



The Company conducted a sensitivity analysis of various drivers using the simulation modeling software, *System Optimizer* (SO). The expansion plans produced by SO were compared and six portfolios that encompass the impact of the range of input sensitivities evaluated were identified[7]. An overview of the base planning assumptions and sensitivities considered is outlined below:

- Impact of potential carbon constraints
    - Portfolios were evaluated under scenarios that included the impacts of potential future carbon emission regulations. The final rule of the Clean Power Plan was published in the Federal Register October 23rd, 2015 which aims to reduce CO_2 emissions from existing electric utility stationary sources. The Supreme Court granted a stay of this rule February 9th 2016 pending challenges from state and industry groups to the U.S. Court of Appeals for the D.C. Circuit. There is much

[7] An additional portfolio (No CO_2 constraints) was also developed, but was not evaluated as a potential base case portfolio through the Portfolio Analysis process.

uncertainty regarding the final outcome and timing of this rule but for the purposes of this IRP the CPP was used as a basis for evaluating potential impacts of carbon constraints. Two potential outcomes of the CPP were evaluated to provide guidance on the impact to existing, and potentially future units, over the planning horizon:

- Carbon Constraint #1: Carbon Tax – Incorporated an intrastate CO_2 tax starting in 2022 that was applied to existing coal and gas units.

- Carbon Constraint #2: System Mass Cap – An alternate means of compliance for CPP in which total system CO_2 emissions were constrained starting in 2022 and declined until 2030. Total system emission were held flat from 2030 throughout the planning horizon.

- An additional sensitivity without any carbon restrictions (no Carbon Tax, no System Mass Cap) was also performed.

- 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, unless otherwise noted. Based on this assumption, Asheville Coal Units 1 & 2 were retired in November 2019 consistent with the Company's CPCN to replace the generation with new combined cycle units.

  - 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.

    - A sensitivity was performed assuming an additional 20 year license renewal of existing nuclear units at the end of the current license life of 60 years.

  - Combustion Turbines – Based on a prior condition assessment 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 and 6 are not counted on to contribute capacity to the DEP system throughout the planning horizon. Additionally, Darlington 11 was retired in November 2015. The Blewett and Weatherspoon CTs are expected to be retired in 2027.

- Coal and natural gas fuel prices
  - Short-term pricing: Natural gas prices were based on market observations from 2017 through 2026 transitioning to fundamental prices by 2032. Coal prices were based on market observations from 2017 through 2021 transitioning to fundamental prices by 2027.
  - Long-term pricing: Based on the Company's fundamental fuel price projections.
    - Sensitivities - A high fuel sensitivity was performed where the average Compound Annual Growth Rate (CAGR) for coal and gas was increased by 0.5% through 2035 and a low fuel sensitivity where the average CAGR for coal and gas was decreased by 1% CAGR through 2035.
- Capital Cost Sensitivities
  - All Assets (Nuclear, CC/CT, Renewables)
    - High Capital – Increased the inflation rate from 2.5% to 4%.
    - Low Capital – Decreased the inflation rate from 2.5% to 1%.
  - Renewables Only: Solar facility costs continue to decrease through 2020 with a 30% Federal ITC through 2019, 26% ITC in 2020, 22% ITC in 2021 and 10% ITC thereafter.
    - Low Cost - To determine if a lower cost would impact the economic selection of additional solar resources, a capital cost sensitivity was performed where solar prices continue to decrease through 2025 with the same ITC assumptions as in the Base Case.

- Renewable Penetration

  - Base Penetration - Resources to comply with NC REPS along with solar customer product offerings such as Green Source and SC DER were input as existing resources. As described in Chapter 5, qualified facilities that the Company is required to purchase under PURPA and who do not sell renewable energy certificates to the Company are captured as non-compliance renewable purchases in the IRP as well. Below is an overview of the solar base planning assumptions and the sensitivities performed:

    - Higher Solar Penetration – To assess the impact if additional, non-compliance solar resources were installed on the system beyond the Base Case. The amount of base solar was increased by 789 MW by 2031.

    - Low Solar Penetration – To assess the potential impact of lower solar penetration levels due to lower fuel prices for more traditional generation technologies, higher solar installation and interconnection costs, lower avoided costs, and/or less favorable PURPA terms. The amount of base solar was decreased by 235 MW by 2031.

    - Under the System CO_2 Mass Cap paradigm, additional economic solar was allowed to be selected up to 10% of the total system energy. Incremental solar integration costs were added as a capital cost based on total solar added to the system *after* economic selection in SO.[8]

- Energy Efficiency

  - Base EE corresponds to the Company's current projections for achievable cost-effective EE program acceptance.

    - High EE – The high case EE/DSM savings included in the IRP modeling assumed a 50% increase in participation for the majority of the Base Case programs as further explained in Appendix D. By 2031, this accounts for an additional 173 MW reduction in total winter load.

- Nuclear Selection – New generic nuclear was included as a resource option in both the Carbon Tax and the System Mass Cap portfolios.

[8] Solar integration costs represented in the Duke Energy Photovoltaic Integration Study published by Pacific Northwest National Lab in March 2014.

- A sensitivity was performed assuming a combination of higher penetration of solar (High Solar Penetration as described above) and a higher penetration of EE (High EE as described above) under a System Mass Cap restriction. The purpose of the sensitivity was to determine the impact on additional economically selected nuclear generation.

- High and Low Load – Sensitivities were performed assuming changes in load of +6.5% starting in 2021 for High Load and – 6.5% for Low Load on average through 2031.

- A sensitivity was performed assuming joint planning with DEP and DEC to demonstrate the benefits of shared resources and how new generation could be delayed. .

Results

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

Initial Resource Needs

- 2017 - The 2016 IRP reflects the replacement of the existing Sutton CTs with two LM6000 dual-fueled, fast start, black start CTs totaling 100 MW. The new CTs are scheduled to be in-service in June 2017.

- 2019 – Asheville Units 1 and 2 are being retired in November 2019 and replaced with two CCs with combined generation of 580 MW.

- 2021 - The first resource need in DEP other than the fast start CTs and the Asheville CCs listed above is 2022. Combined cycle generation was selected optimally for the in all sensitivities except for the low load sensitivity. In the low load sensitivity the CC was delayed from 2022 to 2023.

- One Balancing Authority - The first resource needs are CCs, one in DEP in 2022 and one in DEC in 2023. When planning as One Balancing Authority the DEP and DEC CCs are not delayed but the 2023 CT need in DEP and the 2025 CT need in DEC are delayed until 2026.

New Nuclear Selection – The Carbon Tax only applies to existing coal and gas generation and new nuclear does not have a carbon advantage over new CC generation. Without a carbon advantage new nuclear is not economically selected, however system carbon emission continue increase into the future. In the System Mass Cap constrained cases, additional generic nuclear is needed 2034 timeframe to maintain flat CO_2 emissions after 2030. In the sensitivity with the inclusion of higher EE and higher renewables the additional generic nuclear is still needed in 2034.

Gas Firing Technology Options – In general, the first need was shown to be best met with CC generation, followed by CT generation through 2030. Only in the High Load sensitivity was additional CC selected during this timeframe.

Renewable Generation – In the cases developed under a Carbon Tax paradigm, no additional solar generation in excess of the base assumptions was selected. This was due in part due to the significant level of solar already in the Base Case resource plan which reduces the value of incremental solar on the system. In the low cost solar sensitivity where prices continued to decrease until 2026, additional economic solar was selected in several years beyond the study period. In the System Mass Cap paradigm, additional economic solar was selected in the early 2030s timeframe until 10% of the total energy was met with solar generation.

- *High Renewables* – A sensitivity was performed using the High Renewable case in the Carbon Tax paradigm. The inclusion of increased implementation cost associated with high renewables resulted in a higher revenue requirement than the base expansion plan.

High EE – A sensitivity was performed using the High EE case in the Carbon Tax paradigm. Within the 15 year planning horizon the only change to the expansion plan was a delay in the 2029 CT need to 2030, and a 2031 CT need to 2032. The inclusion of increased implementation cost associated with high EE resulted in a higher revenue requirement than the base expansion plan.

High EE and Renewables – In the System Mass Cap paradigm, a sensitivity was performed with a combination of High EE and Renewables to test the impact on new nuclear generation. The generic nuclear remained in 2035, however a CC need in the early 2030s was delayed several years.

Portfolio Development

Using insights gleaned from the sensitivity analysis, six portfolios were developed. These portfolios were developed in order to assess the relative value of various generating technologies including CCs, CTs, Renewables, and Nuclear, as well as, EE under multiple scenarios. Portfolios 1 – 4 were developed under a Carbon Tax paradigm where varying levels of an intrastate CO_2 tax were applied to existing coal and gas units as envisioned in EPA's CPP. Portfolios 5 and 6 were developed under a System CO_2 Mass Cap that represented an alternative outcome of the CPP. It should be noted that while Portfolios 5 and

6 could meet the requirements of the Carbon Tax constraints, Portfolios 1 – 4 would not meet the CO_2 system mass cap. A description of the six portfolios follows:

Portfolio 1 (Base Case)
This portfolio represents the majority of expansions plans identified through the SO analysis. While CCs are the preferred initial generating option in both DEP and DEC, CTs make up the majority of additional resources added over the 15 year planning horizon. This portfolio includes base EE and renewable assumptions.

Portfolio 2 (High Renewables, Base EE)
This portfolio includes high renewables capacity through the planning period. In DEP, the high renewables assumption has the effect of delaying a 2031 CT need by one year in the 15 year planning horizon. Beyond the 15 year horizon, a CC and additional CTs are delayed by one to two years with increased renewable capacity. This portfolio also includes base EE assumptions.

Portfolio 3 (High EE, Base Renewables)
This portfolio includes high EE targets through the planning period. The high EE assumption has the effect of delaying the 2029 CT need and a 2031 CT need by one year in the 15 year planning horizon. This portfolio also includes base renewable assumptions.

Portfolio 4 (CC centric, Base EE/Renewables)
This portfolio replaces a grouping of CTs in the mid 2020's with a single CC in 2026 along with replacing a grouping of CTs in 2031 with a single CC in the same year. This portfolio includes base renewable and base EE assumptions.

Portfolio 5 (System Mass Cap – Additional nuclear generation, Base EE/Renewables)
This portfolio was developed under a System Mass Cap carbon constraint. This expansion plan is similar to Portfolio #1 through 2029, however a group of CTs in the early 2030s are replaced by a single CC in 2031. Additionally, one new nuclear unit is shown in 2035 in DEP and one new nuclear unit, in addition to Lee Nuclear, is also required in DEC to meet the carbon constraint. This portfolio includes base renewable and base EE assumptions plus additional economically selected solar in the 2030s.

Portfolio 6 (System Mass Cap –Additional nuclear generation, High EE/Renewables)
Similar to Portfolio #5, this portfolio was developed under a System Mass Cap carbon constraint. This portfolio includes both high EE targets and high renewables assumptions. Through 2031, this expansion plan converts a 2031 CC need from Portfolio #5 to a CT need,

and continues to show a new nuclear plant in 2035 in DEP and one new nuclear plant, in addition to Lee Nuclear, in DEC. Additional economic solar is not selected before 2035.

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

Table A-1 Duke Energy Progress Portfolio Summary Plans

Year	Portfolio #1 (CT Centric)	Portfolio #2 (High Renewable)	Portfolio #3 (High EE)	Portfolio #4 (High CC)	Portfolio #5 (System Mass Cap)	Portfolio #6 (System Mass Cap - High EE / High Renewables)
2017						
2018						
2019						
2020						
2021	1123 MW CC	1123 MW CC	1123 MW CC	1123 MW CC	1123 MW CC	1123 MW CC
2022	435 MW CT	435 MW CT	435 MW CT	435 MW CT	435 MW CT	435 MW CT
2023						
2024						
2025	435 MW CT	435 MW CT	435 MW CT	1123 MW CC	435 MW CT	435 MW CT
2026						
2027	435 MW CT	435 MW CT	435 MW CT		435 MW CT	435 MW CT
2028	435 MW CT	435 MW CT			435 MW CT	
2029			435 MW CT	435 MW CT		435 MW CT
2030	1305 MW CT	870 MW CT	870 MW CT	1123 MW CC	1123 MW CC	870 MW CT
2031		435 MW CT	435 MW CT		90 Incremental Solar	
2017 - 2031 Total	1123 MW CC 3045 MW CT 0 Generic Nuclear 0 Incremental Solar	1123 MW CC 3045 MW CT 0 Generic Nuclear 0 Incremental Solar	1123 MW CC 3045 MW CT 0 Generic Nuclear 0 Incremental Solar	3369 MW CC 870 MW CT 0 Generic Nuclear 0 Incremental Solar	2246 MW CC 1740 MW CT 0 Generic Nuclear 90 Incremental Solar	1123 MW CC 2610 MW CT 0 Generic Nuclear 0 Incremental Solar

*Note: Timing for all resources in the above table are December 1st of the year indicated. Throughout the remainder of the document timing is based on units in service in January 1st of the year indicated. Incremental solar is "economically" selected solar beyond the base and high renewable assumptions.

Table A-2 DEP Cumulative Solar Summary (Nameplate MWs)

Year	Portfolio #1	Portfolio #2	Portfolio #3	Portfolio #4	Portfolio #5	Portfolio #6
2017	1,710	1,769	1,710	1,710	1,710	1,769
2018	1,990	2,089	1,990	1,990	1,990	2,089
2019	2,303	2,472	2,303	2,303	2,303	2,472
2020	2,559	2,797	2,559	2,559	2,559	2,797
2021	2,810	3,048	2,810	2,810	2,810	3,048
2022	2,969	3,384	2,969	2,969	2,969	3,384
2023	3,015	3,626	3,015	3,015	3,015	3,626
2024	3,049	3,817	3,049	3,049	3,049	3,817
2025	3,081	3,995	3,081	3,081	3,081	3,995
2026	3,113	4,175	3,113	3,113	3,113	4,175
2027	3,145	4,357	3,145	3,145	3,145	4,357
2028	3,178	4,542	3,178	3,178	3,178	4,542
2029	3,212	4,728	3,212	3,212	3,212	4,728
2030	3,244	4,911	3,244	3,244	3,244	4,911
2031	3,270	5,062	3,270	3,270	3,360	5,062

4. Perform Portfolio Analysis

The six portfolios identified in the screening analysis were evaluated in more detail with an hourly production cost model called PROSYM under several scenarios. The four scenarios are summarized in Table A-3 and included sensitivities on fuel, carbon, and capital cost.

Table A-3 Scenarios for Portfolio Analysis

	Carbon Tax/No Carbon Tax Scenarios[1]	Fuel	CO_2	CAPEX
1	Current Trends	Base	CO_2 Tax	Base
2	Economic Recession	Low Fuel	No CO_2 Tax	Low
3	Economic Expansion	High Fuel	CO_2 Tax	High

[1]Run Portfolios 1 - 4 through each of these 3 scenarios

	System Mass Cap Scenarios[2]	Fuel	CO_2	CAPEX
4	Current Trends - CO_2 Mass Cap	Base	Mass Cap	Base

[2]Run Portfolios 5 - 6 through this single MC2 scenario

Portfolios 1 through 4 were analyzed under a current economic trend scenario (Scenario #1), an economic recession scenario (Scenario #2), and an economic expansion scenario (Scenario #3). Portfolios 5 & 6 were only run under the Current Trends – CO_2 Mass Cap scenario (Scenario #4).

Under a System Mass Cap for carbon, fuel price and capital cost will have little impact on the optimization of the system as the carbon output of the various generators will control dispatch to a greater extent than the fuel price.

Portfolio 1 – 4 Analysis

Table A-4 below summarizes the present value revenue requirements (PVRR) of each portfolio compared to Portfolio #4 over the range of scenarios and sensitivities[9].

Table A-4 Delta PVRR for Portfolios #1 - #4 under Scenarios #1-#3

Delta PVRR 2016 - 2061, $Billions compared to Portfolio #1

Portfolio	Scenario #1 (Current Trends)	Scenario #2 (Economic Recession)	Scenario #3 (Economic Expansion)
Portfolio #1 (Base Case)	$0	$0	$0
Portfolio #2 (High Renew)	$1,184	$1,598	$1,522
Portfolio #3 (High EE)	$76	$316	$13
Portfolio #4 (High CC)	$636	$814	$652

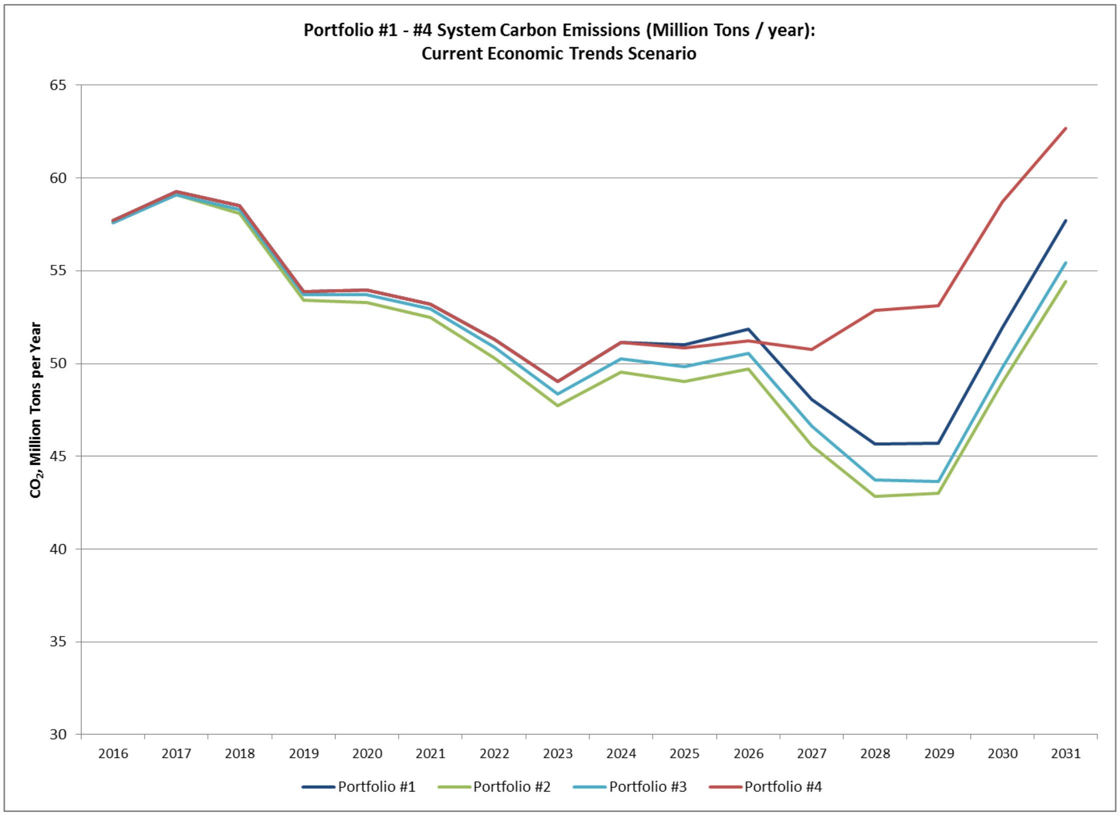
*Note: Positive values indicate Portfolio #1 is a lower cost, Negative values indicate Portfolio #1 is a higher cost

[9] 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 three scenarios, Portfolio #1 (Base Case) was the lowest cost portfolio. The costs of Portfolios 2 and 3 were negatively impacted by expanding the amount of renewable resources beyond the NC REPS requirements and energy efficiency above the Base Case assumptions. However, Portfolio #3 (High EE) had a PVRR that was nearly as low as Portfolio #1 when capital costs and fuel prices were increased in the Economic Expansion scenario. Portfolio #2 (High Renewables) had the lowest carbon footprint in each of the three scenarios evaluated. The higher capital cost and fixed gas pipeline costs associated with combined cycles caused Portfolio #4 (High CC) to have a higher cost than Portfolio #1.

Without the addition of new nuclear to replace retiring nuclear units, the CO_2 emissions increase significantly in the 2030 to 2035 timeframe. Figure A–2 illustrates this point by comparing the cumulative DEP and DEC total system CO_2 emissions of the Portfolios 1 - 4 through 2031 in the Current Trends scenario. To this point, when Robinson 2 is retired in 2030 all Portfolios experience increased carbon emissions.

Figure A-2 Cumulative DEP & DEC System Carbon Emissions Summary for Portfolios 1-4– Current Trends Scenario



Portfolio 5 & 6 Analysis

Table A-5 below summarizes the revenue requirements of Portfolios #5 and #6 under Scenario #4.

Table A-5 Delta PVRR for Portfolios #5 & #6 under Scenario #4

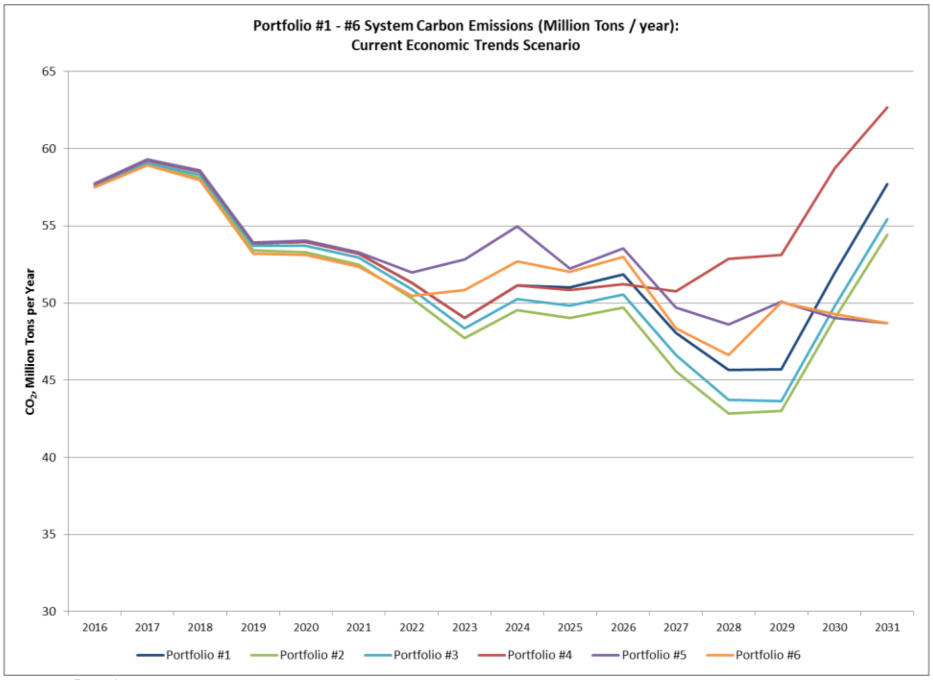
Delta PVRR 2016 - 2061, $Billions compared to Portfolio #5

Portfolio	Scenario #1 (Current Trends)
Portfolio #5 (System Mass Cap Base)	$0
Portfolio #6 (High EE / Renew)	$829

The high EE and high renewable combination led to a higher PVRR versus the Base Case under a System Mass Cap carbon plan. The $1.7B savings in system production costs was not enough to overcome the $2.5B capital cost of the high EE/high renewable portfolio.

Cumulative DEP and DEC system carbon emissions for both Portfolio #5 and Portfolio #6 average under 50 Million tons/year by the late-2020s and are projected to remain flat to declining beyond the study period as shown in Figure A-3.

Figure A-3 Cumulative DEP & DEC System Carbon Emissions Summary for Portfolios 1-6– Current Trends Scenario



Conclusions

For planning purposes, Duke Energy considers the potential impact of a future where carbon emissions are constrained as the base plan. Portfolio #1 is the least cost portfolio from a revenue requirement basis in the Carbon Tax paradigm, however its carbon footprint would not be sustainable in the long-term in a System CO_2 Mass Cap scenario if new nuclear generation was not available in the early 2030s. 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 sixty years.

Duke Energy's current modeling practice uses a proxy CO_2 price forecast from a third party to simulate compliance where carbon emissions are constrained under the now stayed EPA Clean Power Plan. With the stay, the future of CO_2 legislation is still uncertain, and a system mass cap on carbon emissions is still a possibility. Portfolio #1 was chosen as the Base Case portfolio because the short term build plan would keep the Company on track if a System CO_2 Mass Cap were implemented, and it was the least cost portfolio from a revenue requirements perspective.

Value of Joint Planning

To demonstrate the value of sharing capacity with DEP, a Joint Planning Case was developed to examine the impact of joint capacity planning on the resource plans. The impacts were determined by comparing how the combined Base Cases of DEP and DEC would change if a 17% minimum winter 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 1 for DEP and DEC to a combined Joint Planning Case in which existing and future capacity resources could be shared between DEP and DEC to meet the 17% minimum winter planning reserve margin. In this Joint Planning Case, sharing the Lee Nuclear Station on a load ratio basis with DEP was the most economic selection. Table A-4 shows the base expansion plans (Portfolio #1 for both DEP and DEC) through 2031, if separately planned, compared to the Joint Planning Case. The sum total of the two combined resource requirements is then compared to the amount of resources needed if DEP and DEC were able to jointly plan for capacity.

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

	DEC	DEP	Joint Planning (1BA)
2021		1123 MW CC	1123 MW CC
2022	1123 MW CC	435 MW CT	1123 MW CC
2023			
2024	435 MW CT		
2025		435 MW CT	870 MW CT
2026	1117 MW Lee Nuc 1		1117 MW Lee Nuc 1
2027		435 MW CT	435 MW CT
2028	1117 MW Lee Nuc 2	435 MW CT	1117 MW Lee Nuc 2
2029			
2030		1305 MW CT	1740 MW CT
2031	435 MW CT		1305 MW CT
2016 - 2031 Total	1123 MW CC 870 MW CT 1117 MW Lee Nuc 1 1117 MW Lee Nuc 2 0 Generic Nuclear 0 Incremental Solar	1123 MW CC 3045 MW CT 0 MW Lee Nuc 1 0 MW Lee Nuc 2 0 Generic Nuclear 0 Incremental Solar	2246 MW CC 4350 MW CT 1117 MW Lee Nuc 1 1117 MW Lee Nuc 2 0 Generic Nuclear 0 Incremental Solar
Average Winter Reserve Margin (2021 thru 2031)	19.4%	18.6%	18.4%
DEC / DEP Average Reserve Margin with Separate & Joint Planning (2021 thru 2031)	19.0%		
SO Calculated PVRR thru 2061, $B	$124.2		$123.6

*Note: Timing for all resources in the above table are December 1st of the year indicated other than Lee Nuclear 1, which is assumed as November 2026, and Lee Nuclear 2, which is assumed as May 2028. Throughout the remainder of the document timing is based on units in service in January 1st of the year indicated.

A comparison of the DEP and DEC Combined Base Case resource requirements to the Joint Planning Scenario requirements illustrates the ability to defer CT resources over the 2016 to 2031 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 19.0% and 18.4%, respectively, from the first resource need in 2021 through 2031. The lower reserve margin in the Joint Planning Case indicates that DEP and DEC more efficiently and economically meet capacity needs when planning for capacity jointly. This is reflected in a total PVRR savings of $0.6 billion for the Joint Planning Case as compared to the Base Case.

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 December of 2021 to meet the minimum reserve margin requirement in the winter of 2022. The results of this analysis show that this need is best met with CC generation.

2. The ability to jointly plan capacity with DEP provides customer savings by allowing for the deferral of new generation resources over the 2017 through 2031 planning horizon.

3. New nuclear generation is selected as an economic resource in a System CO_2 Mass Cap future as identified in Portfolios 5 & 6. In the 15-year planning horizon, the addition of two additional generic nuclear units, one in DEC and the other in DEP, were selected prior to 2040.

Portfolio 1 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 2015, Duke Energy Progress' nuclear, gas-fired and coal-fired generating units met the vast majority of customer needs by providing 44%, 34% and 21%, respectively, of Duke Energy Progress' energy from generation. Hydro-electric 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 and South Carolina with plant statistics, and the system's total generating capability.

Existing Generating Units and Ratings [1, 3]
All Generating Unit Ratings are as of January 1, 2016.

Coal						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Asheville	1	192	189	Arden, NC	Coal	Intermediate
Asheville	2	192	189	Arden, NC	Coal	Intermediate
Mayo [2]	1	746	727	Roxboro, NC	Coal	Intermediate
Roxboro	1	380	379	Semora, NC	Coal	Intermediate
Roxboro	2	673	671	Semora, NC	Coal	Intermediate
Roxboro	3	698	691	Semora, NC	Coal	Intermediate
Roxboro [2]	4	711	698	Semora, NC	Coal	Intermediate
Total Coal		3,592	3,544			

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	63	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	2	64	48	Hartsville, SC	Oil	Peaking
Darlington	3	63	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	65	51	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	8	66	48	Hartsville, SC	Oil	Peaking
Darlington	9	65	52	Hartsville, SC	Oil	Peaking
Darlington	10	65	51	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	159	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	6	179	153	Hamlet, NC	Natural Gas/Oil	Peaking
Sutton	1	12	11	Wilmington, NC	Oil/Natural Gas	Peaking
Sutton	2A	31	24	Wilmington, NC	Oil/Natural Gas	Peaking
Sutton	2B	33	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	185	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		2,553	2,208			
Total SC		911	735			
Total CT		3,464	2,943			

Combined Cycle						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Lee	CT1A	223	177	Goldsboro, NC	Natural Gas/Oil	Base
Lee	CT1B	222	176	Goldsboro, NC	Natural Gas/Oil	Base
Lee	CT1C	223	179	Goldsboro, NC	Natural Gas/Oil	Base
Lee	ST1	379	378	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	2,620			

Hydro						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Blewett	1	4	4	Lilesville, NC	Water	Intermediate
Blewett	2	4	4	Lilesville, NC	Water	Intermediate
Blewett	3	4	4	Lilesville, NC	Water	Intermediate
Blewett	4	5	5	Lilesville, NC	Water	Intermediate
Blewett	5	5	5	Lilesville, NC	Water	Intermediate
Blewett	6	5	5	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	227			

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			

Solar						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
NC Solar		44.4	44.4	NC	Solar	Intermittent

Total Generation Capability		
	Winter Capacity (MW)	Summer Capacity (MW)
TOTAL DEP SYSTEM - N.C.	12,308	11,441
TOTAL DEP SYSTEM - S.C.	1,708	1,476
TOTAL DEP SYSTEM	14,016	12,917

Note 1: Ratings reflect compliance with NERC reliability standards and are gross of co-ownership interest as of 12/31/15.

Note 2: Duke Energy Progress completed the purchase from NCEMC of jointly owned Roxboro 4, Mayo 1, Brunswick 1 & 2 and Harris 1units effective 7/31/2015.

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

Planned Uprates			
Unit	Date	Winter MW	Summer MW
Brunswick 1 [1]	May 2018	4	2
Brunswick 2 [1]	May 2019	6	4
Brunswick 2 [1]	May 2021	6	4
Brunswick 2 [1]	May 2023	4	2
Brunswick 2 [1]	May 2019	6	4
Harris 1 [1]	Oct 2016	8	4
Harris 1[1]	May 2018	10	5

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

Retirements				
Unit & Plant Name	Location	Capacity (MW) Winter / Summer	Fuel Type	Retirement Date
Cape Fear 5	Moncure, NC	148 / 144	Coal	10/1/12
Cape Fear 6	Moncure, NC	175 / 172	Coal	10/1/12
Cape Fear 1A	Moncure, NC	14 / 11	Combustion Turbine	3/31/13
Cape Fear 1B	Moncure, NC	14 / 12	Combustion Turbine	3/31/13
Cape Fear 2A	Moncure, NC	15 / 12	Combustion Turbine	3/31/13
Cape Fear 2B	Moncure, NC	14 / 11	Combustion Turbine	10/1/12
Cape Fear 1	Moncure, NC	12 / 11	Steam Turbine	3/31/11
Cape Fear 2	Moncure, NC	12 / 7	Steam Turbine	3/31/11
Darlington 11	Hartsville, SC	67 / 52	Combustion Turbine	11/8/15
Lee 1	Goldsboro, NC	80 / 74	Coal	9/15/12
Lee 2	Goldsboro, NC	80 / 68	Coal	9/15/12
Lee 3	Goldsboro, NC	252 / 240	Coal	9/15/12
Lee 1	Goldsboro, NC	15 / 12	Combustion Turbine	10/1/12
Lee 2	Goldsboro, NC	27 / 21	Combustion Turbine	10/1/12
Lee 3	Goldsboro, NC	27 / 21	Combustion Turbine	10/1/12
Lee 4	Goldsboro, NC	27 / 21	Combustion Turbine	10/1/12
Morehead 1	Morehead City, NC	15 / 12	Combustion Turbine	10/1/12
Robinson 1	Hartsville, SC	179 / 177	Coal	10/1/12
Robinson 1	Hartsville, SC	15 / 11	Combustion Turbine	3/31/13
Weatherspoon 1	Lumberton, NC	49 / 48	Coal	9/30/11
Weatherspoon 2	Lumberton, NC	49 / 48	Coal	9/30/11
Weatherspoon 3	Lumberton, NC	79 / 74	Coal	9/30/11
Sutton 1	Wilmington, NC	98 / 97	Coal	11/27/13
Sutton 2	Wilmington, NC	95 / 90	Coal	11/27/13
Sutton 3	Wilmington, NC	389 / 366	Coal	11/4/13
Total		1,947 MW / 1,812 MW		

Planning Assumptions – Unit Retirements[a]

Unit & Plant Name	Location	Summer Capacity (MW)	Winter Capacity (MW)	Fuel Type	Expected Retirement
Asheville 1	Arden, N.C.	189	192	Coal	11/2019
Asheville 2	Arden, N.C.	189	192	Coal	11/2019
Mayo 1	Roxboro, N.C.	727	746	Coal	6/2035
Roxboro 1	Semora, N.C.	379	380	Coal	6/2032
Roxboro 2	Semora, N.C.	665	673	Coal	6/2032
Roxboro 3	Semora, N.C.	691	698	Coal	6/2035
Roxboro 4	Semora, N.C.	698	711	Coal	6/2035
Robinson 2 [b]	Hartsville, S.C.	741	797	Nuclear	6/2030
Darlington 1	Hartsville, S.C.	52	63	Natural Gas/Oil	1/2020
Darlington 2	Hartsville, S.C.	48	64	Oil	1/2020
Darlington 3	Hartsville, S.C.	52	63	Natural Gas/Oil	1/2020
Darlington 4	Hartsville, S.C.	50	66	Oil	1/2020[c]
Darlington 5	Hartsville, S.C.	52	66	Natural Gas/Oil	1/2020
Darlington 6	Hartsville, S.C.	45	62	Oil	1/2020[c]
Darlington 7	Hartsville, S.C.	51	65	Natural Gas/Oil	1/2020
Darlington 8	Hartsville, S.C.	48	66	Oil	1/2020
Darlington 9	Hartsville, S.C.	52	65	Oil	1/2020
Darlington 10	Hartsville, S.C.	51	65	Oil	1/2020
Sutton 1	Wilmington, N.C.	11	12	Natural Gas/Oil	6/2017
Sutton 2A	Wilmington, N.C.	24	31	Natural Gas/Oil	6/2017
Sutton 2B	Wilmington, N.C.	26	33	Natural Gas/Oil	6/2017
Blewett 1	Lilesville, N.C.	13	17	Oil	6/2027
Blewett 2	Lilesville, N.C.	13	17	Oil	6/2027
Blewett 3	Lilesville, N.C.	13	17	Oil	6/2027
Blewett 4	Lilesville, N.C.	13	17	Oil	6/2027
Weatherspoon 1	Lumberton, N.C.	32	41	Natural Gas/Oil	1/2027
Weatherspoon 2	Lumberton, N.C.	32	41	Natural Gas/Oil	1/2027
Weatherspoon 3	Lumberton, N.C.	33	41	Natural Gas/Oil	1/2027
Weatherspoon 4	Lumberton, N.C.	31	41	Natural Gas/Oil	1/2027
Total		5021	5409		

Note a: Retirement assumptions are for planning purposes only; dates are based on useful life expectations of the unit.
Note b: Nuclear retirements for planning purposes are based on the end of current operating license.
Note c: Darlington Units 4 and 6 are currently not contributing capacity to the DEP system for the 2016 IRP. They are counted as a derate until 2020, when Darlington Units 1-10 are expected to retire.

Planning Assumptions – Unit Additions					
Unit & Plant Name	**Location**	**Summer Capacity (MW)**	**Winter Capacity (MW)**	**Fuel Type**	**Expected Commercial Date**
Asheville CC	Arden, N.C.	495	560	Natural Gas	11/2019
Asheville CT (Potential)	Arden, N.C.	161	186	Natural Gas	12/2023
Sutton CT	Wilmington, N.C.	84	100	Natural Gas	6/2017

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 2016 Forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2017 – 2031 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, appliance efficiency trends, rooftop solar trends, and electric vehicle 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 2016 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. 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 2016 Forecast after all adjustments for Utility Energy Efficiency programs, Solar and Electric Vehicles from 2017-2031 is 1.1%.

The Commercial forecast also uses an SAE model in an effort to reflect naturally occurring as well as government mandated efficiency changes. The three largest sectors in the Commercial class are

Offices, Education and Retail. Commercial is expected to be the fastest growing class, with a projected growth rate of 1.3%, after adjustments.

The Industrial class is forecasted by a standard econometric model, with drivers such as total manufacturing output, textile output, and the price of electricity. Overall, Industrial sales are expected to grow 0.8% over the forecast horizon, after all 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. The forecast of degree days is based on a 30-year average, which is updated every year.

The appliance saturation and 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 were projected using the SAE approach in the Spring 2016 Forecast. The peak forecast was developed using a monthly SAE model, similar to the sales SAE models, which includes monthly appliance saturations and efficiencies, interacted with weather and the fraction of each appliance type that is in use at the time of monthly peak.

<u>Assumptions</u>

Below are the projected average annual growth rates of several key drivers from DEP’s Spring 2015 Forecast.

	2017-2031
Real Income	2.9%
Mfg. IPI	1.8%
Population	1.0%

In addition to economic, demographic, and efficiency trends, the forecast also incorporates the expected impacts of UEE, as well as projected effects of electric vehicles and behind the meter solar technology.

Wholesale

For a description of the Wholesale forecast, please see Appendix H.

Historical Values

It should be noted that long-term structurally decline of the Textile industry and the recession of 2008-2009 have had an adverse impact on DEP sales. The worst of the Textile decline appears to be over, and Moody's Analytics expects the Carolina's economy to show solid growth going forward.

In tables C-1 and C-2 below the history of DEP customers and sales are given. As a note, the values in Table C-3 are not weather adjusted.

Table C-1 Retail Customers (Thousands, Annual Average)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential	1,149	1,174	1,195	1,207	1,216	1,221	1,231	1,242	1,257	1,275
Commercial	210	214	216	215	216	217	219	222	222	226
Industrial	4	4	4	5	5	4	4	4	4	4
Total	1,363	1,392	1,415	1,426	1,437	1,443	1,455	1,468	1,484	1,505

Table C-2 Electricity Sales (GWh Sold - Years Ended December 31)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential	16,664	16,259	17,200	17,000	17,117	19,108	17,764	16,663	18,201	17,954
Commercial	13,314	13,358	14,033	13,940	13,639	14,184	13,709	13,581	13,887	14,039
Industrial	12,741	12,416	11,883	11,216	10,375	10,677	10,573	10,508	10,321	10,288
Military &Other	1,410	1,419	1,438	1,467	1,497	1,574	1,591	1,602	1,614	1,597
Total Retail	44,129	43,451	44,553	43,622	42,628	45,544	43,637	42,355	44,023	43,876
Wholesale	12,210	12,231	12,656	12,868	12,772	12,772	12,267	12,676	13,578	15,782
Total System	56,340	55,682	57,209	56,489	55,400	58,316	55,903	55,031	57,601	59,658

Note: The wholesale values in Table C-2 exclude NCEMPA sales for all years except 2015, and is only included for part of 2015. In Tables C-6 and C-7, however, the values include NCEMPA for the full year, for all years in the forecast.

Utility Energy Efficiency

A new process for reflecting the impacts of UEE on the forecast was introduced in Spring 2015. In the latest forecast the concept of 'Measure Life' for a program was included in the calculations. For example, if the accelerated benefit of a residential UEE program is expected to have occurred 8 years before the energy reduction program would have been otherwise adopted, then the UEE effects after year 8 are subtracted ("rolled off") from the total cumulative UEE. With the SAE models framework, the naturally occurring appliance efficiency trends replace the rolled off UEE benefits serving to continue to reduce the forecasted load resulting from energy efficiency adoption.

The table below illustrates this process.

- Column A: Total energy before reduction of future UEE
- Column B: Total cumulative UEE
- Column C: Column B minus Historical UEE
- Column D: Roll-off amount of the incremental future UEE programs
- Column E: UEE amount to subtract from Column A
- Column F: Total energy after incorporating UEE (column A less column E)

Table C-3 UEE Program Life Process (MWh)

	A	B	C	D	E	F
	Forecast	Total	Column B	Roll-Off	UEE to Subtract	Forecast
	Before UEE	Cumulative UEE	Less Historical UEE	Forecasted UEE	From Forecast	After UEE
2017	65,342	1,624	342	0	342	65,000
2018	65,969	1,838	556	0	556	65,414
2019	66,716	2,042	764	0	764	65,952
2020	66,824	2,222	955	0	955	65,869
2021	67,576	2,401	1,134	0	1,134	66,442
2022	68,450	2,580	1,313	0	1,313	67,137
2023	69,359	2,759	1,491	5	1,486	67,873
2024	70,406	2,939	1,670	15	1,655	68,751
2025	71,237	3,118	1,849	24	1,825	69,413
2026	72,177	3,297	2,027	34	1,994	70,184
2027	73,080	3,476	2,206	63	2,143	70,938
2028	74,095	3,656	2,385	145	2,240	71,855
2029	74,829	3,835	2,564	293	2,270	72,558
2030	75,653	4,015	2,742	477	2,266	73,388
2031	76,440	4,194	2,921	647	2,274	74,166

Results

A tabulation of the utility's forecasts for 2017-2031, including peak loads for summer and winter seasons of each year and annual energy forecasts, both with and without the impact of UEE programs, are shown below in Tables C-4 and C-5.

Load duration curves, with and without UEE programs, follow Tables C-6 and C-7, 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 2017 to 2031.

For the period 2017-2031, the Spring 2016 Forecast projects an average annual compound growth rate of 1.3% for summer peaks and 1.4% for winter peaks. These rates do not reflect the impacts of Duke Energy Progress UEE programs. The forecasted compound annual growth rate for energy is 1.1% before UEE program impacts are subtracted.

If the impacts of new Duke Energy Progress UEE programs are included, the projected compound annual growth rate for the summer peak demand is 1.1%, while winter peaks are forecasted to grow at a rate of 1.3%. The forecasted compound annual growth rate for energy is 0.9% after the impacts of UEE programs are subtracted.

As a note, all of the loads and energy in the tables and charts below are at generation, except for the class sales forecast, which is at the meter.

Table C-4 Retail Customers (Thousands, Annual Average)

	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2017	1,309	231	4	2	1,546
2018	1,325	234	4	2	1,564
2019	1,340	236	4	2	1,582
2020	1,356	239	4	2	1,601
2021	1,371	241	4	2	1,618
2022	1,386	243	4	2	1,635
2023	1,401	246	4	2	1,653
2024	1,416	249	4	2	1,671
2025	1,431	252	4	2	1,689
2026	1,446	255	4	2	1,707
2027	1,461	257	4	2	1,725
2028	1,476	260	4	2	1,742
2029	1,491	263	4	2	1,760
2030	1,506	266	4	2	1,778
2031	1,520	269	4	2	1,796

Table C-5 Electricity Sales (GWh Sold - Years Ended December 31)

	Residential Gwh	Commercial Gwh	Industrial Gwh	Other Gwh	Retail Gwh
2017	17,903	14,147	10,366	1,593	44,010
2018	18,023	14,272	10,452	1,590	44,337
2019	18,161	14,400	10,547	1,588	44,696
2020	18,354	14,568	10,644	1,594	45,160
2021	18,512	14,706	10,721	1,600	45,538
2022	18,711	14,880	10,814	1,597	46,003
2023	18,937	15,063	10,894	1,595	46,488
2024	19,175	15,301	11,000	1,592	47,068
2025	19,369	15,479	11,083	1,590	47,522
2026	19,588	15,700	11,177	1,588	48,053
2027	19,796	15,928	11,266	1,586	48,576
2028	20,079	16,169	11,372	1,584	49,204
2029	20,290	16,388	11,453	1,582	49,712
2030	20,568	16,630	11,544	1,580	50,321
2031	20,831	16,876	11,640	1,578	50,925

Table C-6
Load Forecast without Energy Efficiency Programs and Before Demand Reduction Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2017	13,185	13,190	65,342
2018	13,327	13,336	65,969
2019	13,512	13,527	66,716
2020	13,602	13,653	66,824
2021	13,786	13,872	67,576
2022	13,969	14,085	68,450
2023	14,164	14,296	69,359
2024	14,355	14,511	70,406
2025	14,550	14,721	71,237
2026	14,764	14,942	72,177
2027	14,954	15,146	73,080
2028	15,160	15,365	74,095
2029	15,347	15,573	74,829
2030	15,538	15,787	75,653
2031	15,741	16,010	76,440

Chart C-1
Load Duration Curve without Energy Efficiency Programs and Before Demand Response Programs

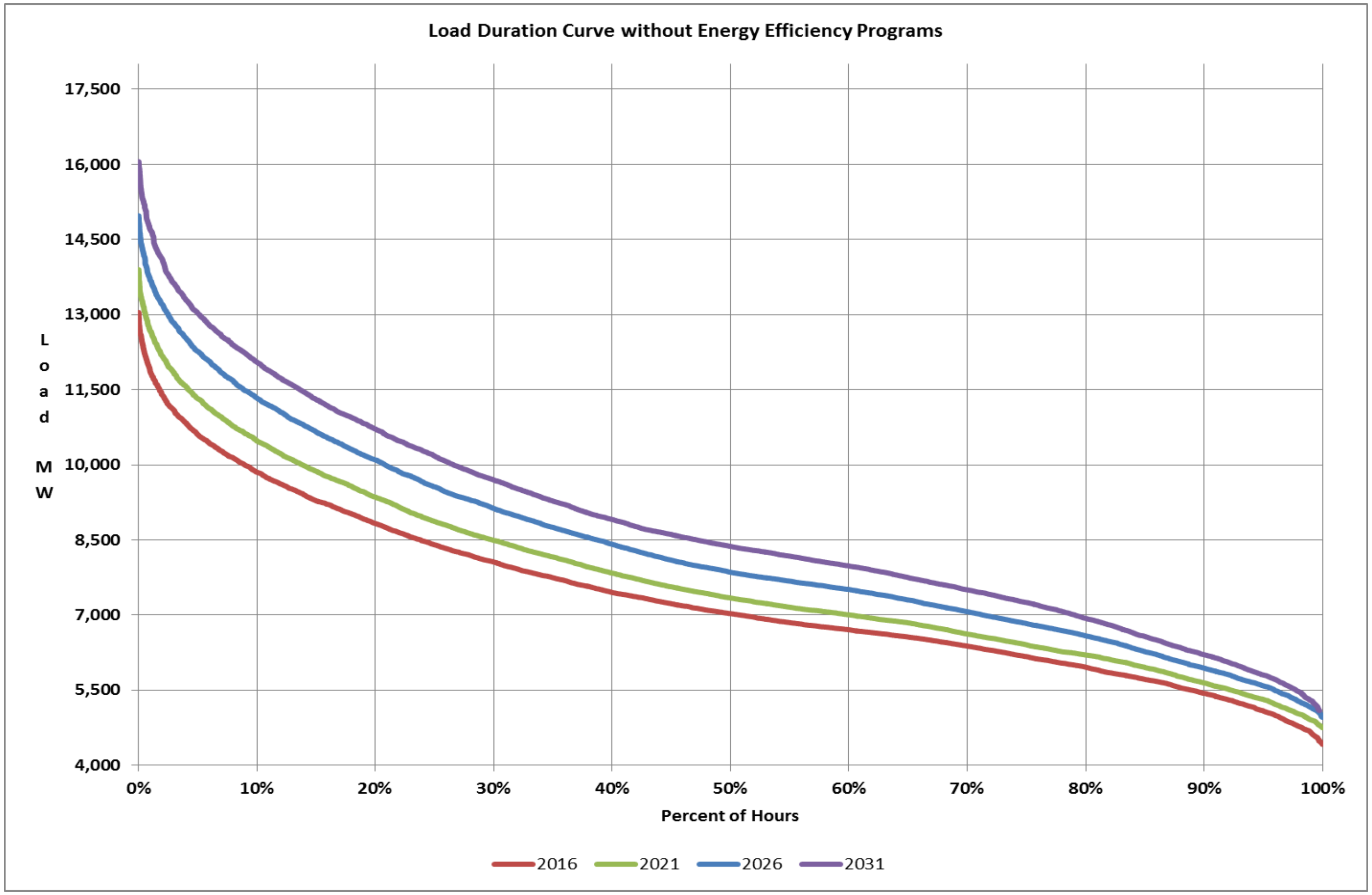
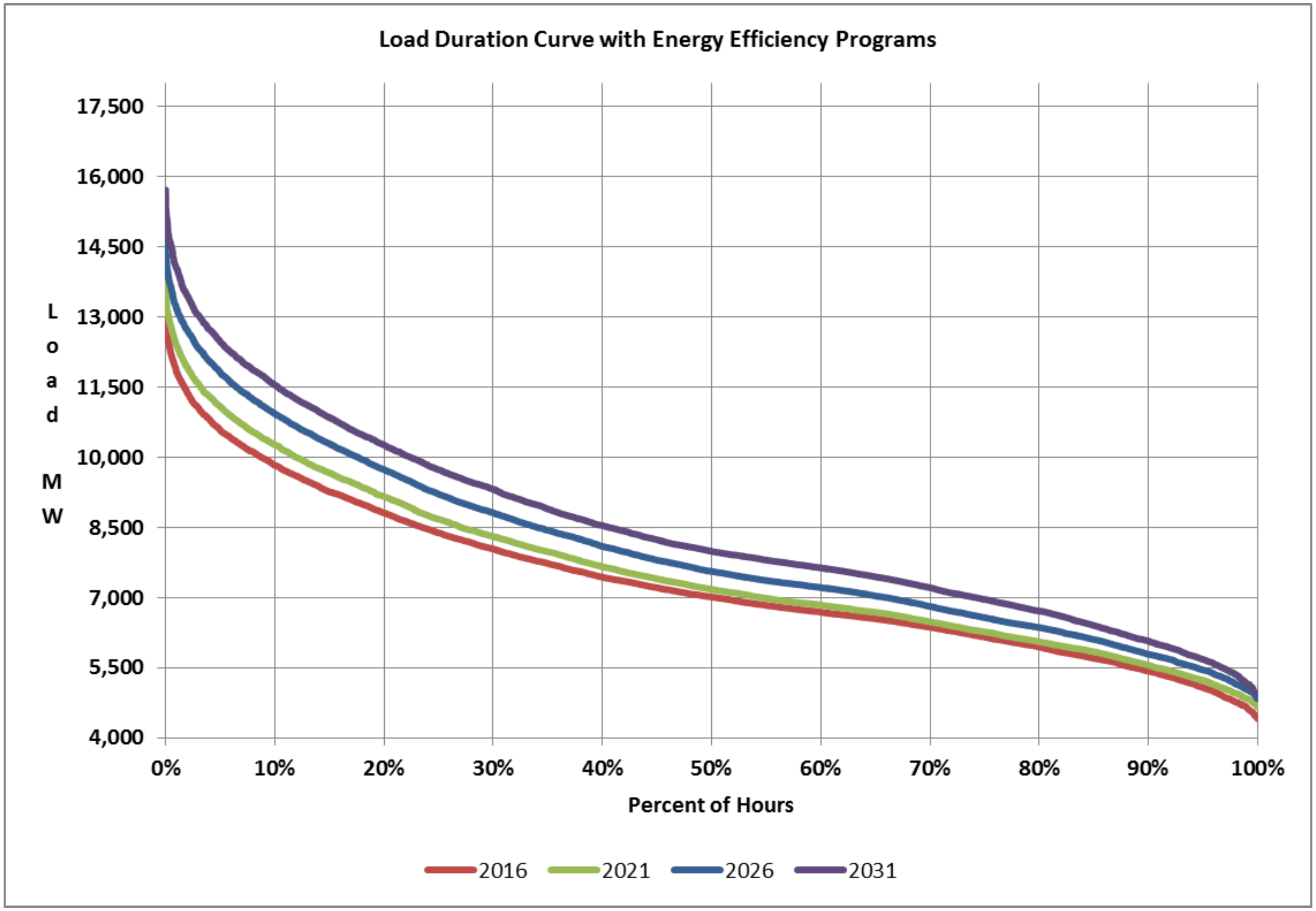


Table C-7
Load Forecast with Energy Efficiency Programs and Before Demand Reduction Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2017	13,127	13,158	65,000
2018	13,234	13,277	65,414
2019	13,385	13,442	65,952
2020	13,444	13,542	65,869
2021	13,599	13,728	66,442
2022	13,753	13,918	67,137
2023	13,919	14,107	67,873
2024	14,083	14,300	68,751
2025	14,249	14,488	69,413
2026	14,435	14,689	70,184
2027	14,601	14,874	70,938
2028	14,792	15,082	71,855
2029	14,973	15,283	72,558
2030	15,164	15,497	73,388
2031	15,365	15,719	74,166

Chart C-2
Load Duration Curve with Energy Efficiency Programs & Before Demand Response 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).

Following are the EE and DSM programs currently available through DEP.

Residential Customer Programs

- Residential Home Energy Improvement
- Residential New Construction
- Residential Neighborhood Energy Saver (Low-Income)
- Residential Appliance Recycling Program
- Residential My Home Energy Report
- Residential Multi-Family Energy Efficiency
- Energy Efficiency Education
- Residential Energy Assessments
- Residential Save Energy and Water Kit
- Residential EnergyWise^{SM} Home

Non-Residential Customer Programs

- Energy Efficiency for Business
- Small Business Energy Saver
- Business Energy Report Pilot
- CIG Demand Response Automation Program
- EnergyWise^{SM} for Business

Combined Residential/Non-Residential Customer Programs

- Energy Efficient Lighting
- Distribution System Demand Response (DSDR)

Energy Efficiency Programs

Energy Efficiency programs are typically non-dispatchable education or incentive-based programs. Energy and capacity savings are achieved by changing customer behavior or through the installation of more energy-efficient equipment or structures. All cumulative effects (gross of Free Riders, at the Plant[10]) since the inception of these existing programs through the end of 2015 are summarized below. Please note that the cumulative impacts listed below include the impact of any Measurement and Verification performed since program inception and also note that a "Participant" in the information included below is based on the unit of measure for specific energy efficiency measure (e.g. number of bulbs, kWh of savings, tons of refrigeration, etc.), and may not be the same as the number of customers that actually participate in these programs. The following provides more detail on DEP's existing EE programs:

Residential EE Programs

Residential Home Energy Improvement Program

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. In 2015, an enhanced version of the program was approved and implemented which expanded the number of HVAC measure options and introducing several new measures. 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
- HVAC Audit
- Insulation Upgrades/Attic Sealing
- High Efficiency Room Air Conditioners

[10] "Gross of Free Riders" means that the impacts associated with the EE programs have not been reduced for the impact of Free Riders. "At the Plant" means that the impacts associated with the EE programs have been increased to include line losses.

- Heat Pump Water Heater
- HVAC Quality Installation
- Smart Thermostat
- Variable Speed Pool Pumps

Due to the timing of approval for these program enhancements discussed above, the expected impacts from this program were not included in the EE forecasts used in this IRP.

Residential Home Energy Improvement Program			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2015	114,832	49,373	34,343

Residential New Construction Program

The Residential New Construction Program incents the installation of high-efficiency heating ventilating and air conditioning and heat pump water heating equipment in new residential construction. Additionally, the Program incents new construction built to or above the 2012 North Carolina Energy Conservation Code's High Efficiency Residential Option (HERO). If elected by a builder or developer constructing to the HERO standard, the Program also offers the homebuyer a Heating and Cooling Energy Usage Limited Guarantee that guarantees the heating and cooling consumption of the dwelling's total annual energy costs.

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			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2015	14,128	21,679	8,083

Note: The participants and impacts are from both the Residential New Construction program and the previous Home Advantage program.

Residential Neighborhood Energy Saver (Low-Income) Program

DEP's Neighborhood Energy Saver Program reduces energy usage through the direct installation of energy efficiency measures within the households of income qualifying residential customers. The Program utilizes a Company-selected vendor to: (1) provide an on-site energy assessment of the residence to identify appropriate energy conservation measures, (2) install a comprehensive package of energy conservation measures at no cost to the customer, and (3) provide one-on-one energy education. Program measures address end-uses in lighting, refrigeration, air infiltration and HVAC applications.

Program participants receive a free energy assessment of their home followed by a recommendation of energy efficiency measures to be installed at no cost to the resident. A team of energy technicians will install applicable measures and provide one-on-one energy education about each measure emphasizing the benefit of each and recommending behavior changes to reduce and control energy usage.

Residential Neighborhood Energy Saver Program			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	27,993	15,829	2,229

Residential Appliance Recycling Program

The Appliance Recycling Program promotes the removal and responsible disposal of operating refrigerators and freezers from DEP residential customers. An eligible refrigerator or freezer must have a capacity of at least 10 cubic feet but not more than 30 cubic feet. The Program recycles approximately 95% of the material from the harvested appliances.

The implementation vendor for this program abruptly discontinued operations in November 2015. As a result, the program is not currently being offered to customers and future potential impacts associated with this program beyond 2015 were not included in this IRP analysis.

Residential Appliance Recycling Program			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2015	47,680	50,738	6,048

Residential My Home Energy Report Program

The My Home Energy Report (MyHER) Program was designed to help customers better understand their energy usage. The program provides customers with a periodic comparative usage report that compares a their energy use to similar residences in the same geographical area based upon the age, size and heating source of the home. Energy saving recommendations are included in the report to encourage energy saving behavior. The reports are distributed up to 12 times per year (delivery may be interrupted during the off-peak energy usage months in the fall and spring). Each customer's usage is compared to the average home (top 50 percent) in their area as well as the efficient home (top 25 percent). Suggested energy efficiency improvements, given the usage profile for that home, are also provided. In addition, measure-specific offers, rebates or audit follow-ups from other Company offered programs are offered to customers, based on the customer's energy profile.

MyHER received regulatory approval during the last quarter of 2014 and eligible customers received their first report during the first quarter of 2015.

Residential My Home Energy Report Program			
	Number of	**Gross Savings (at plant)**	
Capability as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2015	682,389	132,316	35,955

Energy Efficiency Education Program

The Energy Efficiency Education Program is an energy efficiency program available to students in grades K-12 enrolled in public and private schools who reside in households served by Duke Energy Progress. The Program provides principals and teachers with an innovative curriculum that educates students about energy, resources, how energy and resources are related, ways energy is wasted and how to be more energy efficient. The centerpiece of the current curriculum, which is administered by The National Theatre for Children, is a live theatrical production focused on concepts such as energy, renewable fuels and energy efficiency performed by two professional actors. Teachers receive supportive educational material for classroom and student take home assignments. The workbooks, assignments and activities meet state curriculum requirements.

Following the performance, students are encouraged to complete a home energy survey with their family (included in their classroom and family activity book) to receive an Energy Efficiency Starter Kit. The kit contains specific energy efficiency measures to reduce home energy consumption. The kit is available at no cost to all student households at participating schools, including customers and non-customers.

Energy Efficiency Education Program			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2015	10,060	2,284	226

Multi-Family Energy Efficiency Program

The Multi-family Energy Efficiency Program allows DEP to utilize an alternative delivery channel which targets multi-family apartment complexes for energy efficiency upgrades. The Program is designed to help property managers upgrade lighting with energy efficient compact fluorescent light bulbs (CFLs) and also save energy by offering water measures such as bath and kitchen faucet aerators, water saving showerheads and pipe wrap to eligible customers with electric water heating. The Program also offers properties the option of direct install service by a third-party vendor or to use their own property maintenance crews to complete the installations. Post-installation Quality Assurance inspections by an independent third-party are conducted on 20 percent of properties that completed installations in a given month.

The program launched in January 2015 after receiving regulatory approval late in 2014.

Residential Multi-Family Energy Efficiency Program			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2015	347,412	19,822	1,998

Energy Efficient Lighting Program

The Lighting Program launched in January of 2010 and expanded to offer additional measures in January 2013 (now called Energy Efficient Lighting Program). This program works through lighting manufacturers and retailers to offer discounts to DEP customers at the register on CFLs, light emitting diodes (LEDs), and energy-efficient fixtures. Participation levels for all years of the program have been higher than originally forecasted. This success can be attributed to high customer interest in energy efficiency, low socket penetration of energy efficient lighting in the DEP territory and effective promotion of the program in the marketplace.

As the program enters the sixth year, the DEP Energy Efficient Lighting Program will continue to encourage customers to adopt energy efficient lighting through incentives on a wide range of lighting products. Customer education is imperative to ensure customers are purchasing the right bulb for the application in order to obtain high satisfaction with lighting products and subsequent purchases.

Energy Efficient Lighting Program			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2015	23,688,204	1,323,144	204,694

Residential Energy Assessments Program

The Residential Energy Assessments Program provides eligible customers with a free in-home energy assessment performed by a Building Performance Institute (BPI) certified energy specialist designed to help customers reduce energy usage and save money. The BPI certified energy specialist completes a 60 to 90 minute walk through assessment of a customer's home and analyzes energy usage to identify energy savings opportunities. The energy specialist discusses behavioral and equipment modifications that can save energy and money with the customer. The customer also receives a customized report that identifies actions the customer can take to increase their home's efficiency.

In addition to a customized report, customers receive an energy efficiency starter kit with a variety of measures that can be directly installed by the energy specialist. The kit includes measures such as energy efficiency lighting, low flow shower head, low flow faucet aerators, outlet/switch gaskets, weather stripping and an energy saving tips booklet.

The program was approved by the NCUC in February 2016 and a forecast of expected future impacts was included in this IRP.

Save Water and Energy Kit Program

The Save Energy and Water Kit is designed to increase the energy efficiency within single family homes by offering low flow water fixtures and insulated pipe tape to residential customers with electric water heaters. Participants receive a free kit that includes installation instructions and varying numbers (based on the number of full bathrooms in their home) of bath aerators, kitchen aerators, shower heads and pipe insulation tape. The program has a website in place that customers can access to learn more about the program or watch video's produced to aid in the installation of the kit measures.

The program launched in November 2015 and a forecast of expected future impacts was included in this IRP.

Non-Residential EE Programs

Energy Efficiency for Business Program

The Energy Efficiency for Business Program provides incentives to DEP commercial and industrial customers to install high efficiency equipment in applications involving new construction and retrofits and to replace failed equipment.

Commercial and industrial customers can have significant energy consumption but may lack knowledge and understanding of the benefits of high efficiency alternatives. The Program provides financial incentives to help reduce the cost differential between standard and high efficiency equipment, offer a quicker return on investment, save money on customers' utility bills that can be reinvested in their business, and foster a cleaner environment. In addition, the Program encourages dealers and distributors (or market providers) to stock and provide these high efficiency alternatives to meet increased demand for the products.

The program provides incentives through prescriptive measures, custom measures and technical assistance.

- *Prescriptive Measures*: Customers receive incentive payments after the installation of certain high efficiency equipment found on the list of pre-defined prescriptive measures, including lighting; heating, ventilating and air conditioning equipment; and refrigeration measures and equipment.
- *Custom Measures*: Custom measures are designed for customers with electrical energy saving projects involving more complicated or alternative technologies, whole-building projects, or those measures not included in the Non-Residential Energy Efficiency for Business measure list. The intent of the Program is to encourage the implementation of energy efficiency projects that would not otherwise be completed without the Company's technical or financial assistance. Unlike Prescriptive portion of the program, all Custom measure incentives requires pre-approval prior to the project implementation.
- *Technical Assistance*: Technical Assistance incentives are offered for new construction and retrofit application to provide assistance to qualified customers with development or implementation of system and building enhancements. Assistance may include, but is not limited to, feasibility studies, detailed energy audits, and retro-commissioning of existing systems, or for efficiency design or energy modeling for new structures and systems. All measures involving technical assistance incentives must receive pre-approval before implementation.

Energy Efficiency for Business Program			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants***	**MWh Energy**	**Peak kW**
December 31, 2015	358,551,358	358,551	68,745

* Note: One participant equals one kWh.

Small Business Energy Saver Program

The Small Business Energy Saver Program reduces energy usage through the direct installation of energy efficiency measures within qualifying small non-residential customer facilities. Program measures address major end-uses in lighting, refrigeration, and HVAC applications. The program is available to existing non-residential customers that are not opted-out of the Company's EE/DSM rider and have an average annual demand of 100 kW or less per active account.

Program participants receive a free, no-obligation energy assessment of their facility followed by a recommendation of energy efficiency measures to be installed in their facility along with the projected energy savings, costs of all materials and installation, and up-front incentive amount from Duke Energy Progress. Upon receiving the results of the energy assessment, if the customer decides to move forward with the proposed energy efficiency project, the customer makes the final determination of which measures will be installed. The energy efficiency measure installation is then scheduled at a convenient time for the customer and the measures are installed by electrical subcontractors of the Company-authorized vendor.

All aspects of the program are administered by a single Company-authorized vendor. The program is designed as a pay-for-performance offering, meaning that the Company-authorized vendor administering the Program is only compensated for energy savings produced through the installation of energy efficiency measures.

Small Business Energy Saver Program			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2015	95,893,808	95,894	19,445

* Note: One participant equals one kWh.

Business Energy Report Pilot

The Business Energy Report Pilot is a periodic comparative usage report that compares a customer's energy use to their peer groups. Comparative groups are identified based on the customer's energy use, type of business, operating hours, square footage, geographic location, weather data and heating/cooling sources. Pilot participants will receive targeted energy efficiency tips in their report informing them of actionable ideas to reduce their energy consumption. The recommendations may include information about other Company offered energy efficiency programs. Participants will receive at least six reports over the course of a year.

Distribution System Demand Response Program (DSDR)

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 helps DEP implement a least cost mix of demand reduction and generation measures that meet the electricity needs of its customers. With the full implementation of DSDR in June 2014, all of DEP's voltage control capability now falls under the DSDR program.

Distribution System Demand Response Program			
		Gross Savings (at plant)	
Cumulative as of:	Number of Participants	MWh Energy	Summer MW Capability
December 31, 2015	NA	41,988	308

Since DEP's last biennial resource plan was filed on September 2, 2014, there have been 60 voltage control activations through June 30, 2016. The following table shows the date, starting and ending time, and duration for all voltage control activations from July 2014 through June 2016.

Voltage Control			
Date	Start Time	End Time	Duration (H:MM)
7/2/2014	15:00	18:00	3:00
7/9/2014	15:00	16:03	1:03
7/14/2014	15:00	18:00	3:00
7/16/2014	10:00	11:00	1:00
7/23/2014	15:00	18:00	3:00
7/28/2014	15:00	17:30	2:30

Voltage Control			
Date	**Start Time**	**End Time**	**Duration (H:MM)**
8/6/2014	15:00	18:00	3:00
8/12/2014	16:08	16:25	0:17
8/20/2014	15:00	18:00	3:00
8/21/2014	15:00	18:00	3:00
8/22/2014	15:00	17:00	2:00
9/17/2014	13:00	14:00	1:00
11/17/2014	10:00	11:00	1:00
11/19/2014	6:30	9:00	2:30
11/22/2014	17:13	17:29	0:16
12/8/2014	8:06	8:40	0:34
12/12/2014	7:58	8:30	0:32
12/16/2014	8:00	8:30	0:30
1/7/2015	7:00	8:05	1:05
1/8/2015	6:00	9:10	3:10
1/9/2015	7:00	8:05	1:05
1/23/2015	8:21	8:37	0:16
1/28/2015	6:30	8:43	2:13
1/29/2015	6:30	8:38	2:08
2/3/2015	6:30	8:35	2:05
2/6/2015	6:30	8:35	2:05
2/13/2015	6:30	8:41	2:11
2/15/2015	19:00	22:11	3:11
2/16/2015	6:30	9:40	3:10
2/19/2015	6:30	9:40	3:10
2/19/2015	19:00	22:30	3:30
2/20/2015	6:30	7:00	0:30
2/20/2015	7:00	8:30	1:30
2/20/2015	8:30	9:26	0:56
2/20/2015	19:00	22:30	3:30
4/9/2015	17:35	18:11	0:36
4/29/2015	12:30	13:00	0:30
5/19/2015	12:00	13:00	1:00
5/26/2015	11:00	12:00	1:00
6/15/2015	16:00	19:35	3:35
6/16/2015	16:00	19:31	3:31

Voltage Control			
Date	**Start Time**	**End Time**	**Duration (H:MM)**
6/18/2015	15:00	16:56	1:56
6/22/2015	15:00	18:46	3:46
6/23/2015	16:03	16:17	0:14
6/24/2015	12:00	13:35	1:35
6/24/2015	15:00	19:08	4:08
7/7/2015	14:00	15:01	1:01
7/9/2015	16:45	17:28	0:43
7/20/2015	15:30	19:05	3:35
7/21/2015	15:30	19:05	3:35
7/27/2015	16:28	16:34	0:06
8/4/2015	15:30	19:09	3:39
8/5/2015	15:30	19:04	3:34
8/18/2015	14:01	14:18	0:16
8/25/2015	14:00	15:35	1:35
9/2/2015	12:00	13:35	1:35
1/19/2016	6:00	8:37	2:37
1/20/2016	6:00	8:43	2:43
2/7/2016	13:15	13:31	0:16
2/8/2016	6:00	8:51	2:51
2/11/2016	6:00	8:58	2:58
3/7/2016	6:32	7:25	0:53
5/16/2016	9:00	9:25	0:25
5/17/2016	9:00	10:02	1:02
6/5/2016	14:51	15:15	0:24
6/7/2016	15:02	15:12	0:10
6/8/2016	12:30	13:30	1:00
6/16/2016	15:30	17:00	1:30
6/21/2016	12:30	14:09	1:39
6/24/2016	15:30	15:45	0:14
6/29/2016	12:00	13:00	1:00

Demand Side Management Programs

Residential EnergyWise^{SM} Home Program

The Residential EnergyWise^{SM} Home Program allows DEP to install 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 appliance options above, an initial one-time bill credit of $25 following the successful installation and testing of load control device(s) and an annual bill credit of $25 is provided to program participants in exchange for allowing the Company to control the listed appliances.

Residential EnergyWise^{SM} Home Program			
Cumulative as of:	**Number of Participants***	**MW Capability**	
		Summer	**Winter**
December 31, 2015	143,186	281	10.3

* Number of participants represents the number of measures under control.

The following table shows Residential EnergyWise^{SM} Home Program activations that were not for testing purposes from July 1, 2014 through December 31, 2015.

Residential EnergyWise^{SM} Home			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction***
7/8/2014 15:30	7/8/2014 18:00	150	110.3
9/2/2014 15:00	9/2/2014 18:00	180	108.2
1/8/2015 6:30	1/8/2015 9:00	150	9.4
1/9/2015 6:30	1/9/2015 9:30	180	9.2
2/19/2015 6:30	2/19/2015 9:30	180	14.9
2/20/2015 6:30	2/20/2015 9:30	180	16
6/15/2015 15:00	6/15/2015 18:00	180	144
6/16/2015 15:00	6/16/2015 18:00	180	149.5
6/23/2015 15:00	6/23/2015 18:00	180	115.4

7/10/2015 16:30	7/10/2015 17:00	30	227.9
7/21/2015 15:00	7/21/2015 17:30	150	107.1
8/21/2015 16:00	8/5/2015 17:30	90	112.9

EnergyWise[SM] for Business Program

EnergyWise[SM] for Business is both an energy efficiency and demand response program for non-residential customers that allows DEP to reduce the operation of participants air conditioning units to mitigate system capacity constraints and improve reliability of the power grid.

Program participants can choose between a Wi-Fi thermostat or load control switch that will be professionally installed for free on each air conditioning or heat pump unit. In addition to equipment choice, participants can also select the cycling level they prefer (i.e., a 30%, 50% or 75% reduction of the normal on/off cycle of the unit). During a conservation period, DEP will send a signal to the thermostat or switch to reduce the on time of the unit by the cycling percentage selected by the participant. Participating customers will receive a $50 annual bill credit for each unit at the 30% cycling level, $85 for 50% cycling, or $135 for 75% cycling. Participants that have a heat pump unit with electric resistance emergency/back up heat and choose the thermostat can also participate in a winter option that allows control of the emergency/back up heat at 100% cycling for an additional $25 annual bill credit. Participants will also be allowed to override two conservation periods per year.

Participants choosing the thermostat will be given access to a portal that will allow them to set schedules, adjust the temperature set points, and receive energy conservation tips and communications from DEP anywhere they have internet access. In addition to the portal access, participants will also receive conservation period notifications, so they can make adjustments to their schedules or notify their employees of upcoming conservation periods.

The DEP EnergyWise[SM] for Business program was implemented in January 2016.

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

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 is 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 was limited to NERC Level II (EEA2) except for an annual readiness test. More recently, on May 1, 2016, the DC Circuit Court of Appeals mandated vacatur of the provision that included demand response participation in the rule's 100 hour allowance. The vacatur resulted in the inability of existing Emergency Generator Option participants to continue participation as of May 1, 2016, and the need for DEP to begin plans to close the program option and file for approval to revise the rider to only include the Curtailable Option.

CIG Demand Response Automation Statistics			
Cumulative as of:	**Number of Participants**	**MW Capability**	
		Summer	**Winter**
December 31, 2015	59	24.3	14.0

The table below shows information for each CIG Demand Response Automation Program non-test control event from July 1, 2014 through December 31, 2015.

CIG Demand Response Automation – Curtailable Option			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction***
7/8/14 13:00	7/8/14 19:00	360	18.8
7/28/14 13:00	7/8/14 19:00	360	15.9
8/21/14 13:00	8/21/14 19:00	360	16.8
1/8/15 6:00	1/8/15 10:00	240	8.0
2/20/15 6:00	2/20/15 10:00	240	8.6
6/16/15 14:00	6/16/15 19:00	300	20.3
6/23/15 14:00	6/23/15 19:00	300	20.5

CIG Demand Response Automation – Emergency Generator Option			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction***
7/8/14 13:00	7/8/14 19:00	360	0.6
2/20/15 6:00	2/20/15 9:00	180	1.1
6/16/15 14:00	6/16/15 19:00	300	5.1

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.

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. The table below shows curtailable rate activation not for testing during the period from July 1, 2014 through December 31, 2015.

Curtailable Rate Activations			
Date	**Start/End Time**	**Duration (Minutes)**	**MW Load Reduction***
1/8/2015	06:00-10:00	240	240
2/20/2015	06:00-10:00	240	240

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 2015, 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[11]	EE	473	NA	NA	NA
Real Time Pricing (RTP)	DSM	45	NA	105	NA
Commercial & Industrial TOU	DSM	10.9	NA	30,749	NA
Residential TOU	DSM	6.2	NA	28,011	NA
Curtailable Rates	DSM	269	NA	70	2

Future EE and DSM Programs

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.

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

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, Rate Impact Measure Test, Total Resource Cost 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

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

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 NCUC, in their Order Approving Integrated Resource Plans and REPS Compliance Plans regarding the 2014 Biennial IRP's, dated June 26, 2015 in Docket E-100, Sub141, issued the following Orders relative to EE/DSM analysis and forecasts:

7. *That the IOUs should continue to monitor and report any changes of more than 10% in the energy and capacity savings derived from DSM and 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.*

8. *That each IOU shall continue to include a discussion of the status of EE market potential studies or updates in their future IRPs.*

These two Orders that are specific to EE and DSM are addressed in the following sections.

Forecast Methodology

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.

The Forefront study results are suitable for IRP purposes and for use in long-range system planning models. This study also helps to inform utility program planners regarding the extent of EE opportunities and to provide broadly defined approaches for acquiring savings. This study did not, however, attempt to closely forecast EE achievements in the short-term or from year to year. Such an annual accounting is highly sensitive to the nature of programs adopted as well as the timing of the introduction of those programs. As a result, it was not designed to provide detailed specifications and work plans required for program implementation. The 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, feedback from the DSM Collaborative and with the possible assistance of implementation contractors. An updated Market Potential Study is currently underway and the results of that study should be available in time for the next DEP IRP process.

DEP prepared a Base Portfolio savings projection that was based on DEP's five year program plan for 2016-2020. For periods beyond 2020, the Base Portfolio assumed that the annual savings projected for 2020 would continue to be achieved in each year thereafter until such time as the total cumulative EE projections reached approximately 60% of the Economic Potential as estimated by the Market Potential Study described above. This level of cumulative EE savings was projected to be reached in 2033. For periods beyond 2033, DEP assumed that additional EE savings impacts would continue to be achieved, however, the annual amount of those savings would be reduced to a level required to maintain the same cumulative EE achievement as a percentage of the Economic Potential. In other words, sufficient EE savings would be added to keep up with growth in the customer load.

Additionally, for the Base Portfolio described above DEP included an assumption for the purpose of the IRP analysis that, when the EE measures included in the forecast reach the end of their useful lives, the impacts associated with these measures are removed from the future projected EE impacts. This concept of "rolling off" the impacts from EE programs is explained further in Appendix C of this document.

The table below provides the Base Portfolio projected MWh load impacts of all DEP EE programs implemented since 2007 on a Gross and Net of Free Riders basis. Forecasted DSDR program impacts are adjusted each year based on actual results from the prior year and updated retail peak and system load forecasts. The Company assumes total EE savings will continue to grow on an annual basis throughout the planning period until reaching approximately 60% of the Economic Potential in about 2034, however, the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan. Please note that this table includes a column that shows historical EE program savings since the inception of the EE programs in 2009 through the end of 2015, which accounts for approximately an additional 2,070 gigawatt-hour (GWh) of Gross energy savings.

The following forecast is for the Base Portfolio without the effects of "rolloff":

Base Portfolio MWh Load Impacts of EE Programs

	Annual MWh Load Reduction - Gross				Annual MWh Load Reduction - Net			
	Including measures added in 2016 and beyond			Including measures added since 2007	Including measures added in 2016 and beyond			Including measures added since 2007
Year	Post SB-3 EE	DSDR	Total		Post SB-3 EE	DSDR	Total	
2007-15				2,069,991				1,528,724
2016	290,105	48,723	338,828	2,408,819	235,374	48,723	284,097	1,812,821
2017	556,862	49,325	606,187	2,676,178	448,751	49,325	498,076	2,026,800
2018	820,610	49,971	870,581	2,940,572	662,640	49,971	712,611	2,241,335
2019	1,071,028	50,602	1,121,629	3,191,621	865,695	50,602	916,296	2,445,020
2020	1,295,170	51,178	1,346,348	3,416,339	1,044,683	51,178	1,095,861	2,624,585
2021	1,519,312	51,670	1,570,983	3,640,974	1,223,369	51,670	1,275,040	2,803,764
2022	1,743,455	52,195	1,795,650	3,865,641	1,402,055	52,195	1,454,250	2,982,974
2023	1,967,597	52,701	2,020,299	4,090,290	1,580,740	52,701	1,633,442	3,162,166
2024	2,191,740	53,349	2,245,089	4,315,080	1,759,426	53,349	1,812,775	3,341,499
2025	2,415,882	53,912	2,469,794	4,539,785	1,938,112	53,912	1,992,024	3,520,748
2026	2,640,024	54,615	2,694,639	4,764,630	2,116,797	54,615	2,171,412	3,700,136
2027	2,864,167	55,277	2,919,444	4,989,435	2,295,483	55,277	2,350,760	3,879,484
2028	3,088,309	56,042	3,144,351	5,214,343	2,474,169	56,042	2,530,211	4,058,935
2029	3,312,451	56,700	3,369,152	5,439,143	2,652,854	56,700	2,709,555	4,238,279
2030	3,536,594	57,432	3,594,026	5,664,017	2,831,540	57,432	2,888,972	4,417,696
2031	3,760,736	58,236	3,818,972	5,888,963	3,010,226	58,236	3,068,462	4,597,186

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

The MW impacts from the EE programs are included in the Load Forecasting section of this IRP. The table below provides the Base Portfolio projected MW load impacts of all current and projected DEP DSM.

Base Portfolio Load Impacts of DSM Programs

	Annual Peak MW Reduction - Gross				Annual Peak MW Reduction - Net			
Year	DSM	DSDR	Pre SB-3 Programs	Total Annual Peak	DSM	DSDR	Pre SB-3 Programs	Total Annual Peak
2016	334	222	270	825	334	222	270	825
2017	372	224	273	869	372	224	273	869
2018	409	228	276	913	409	228	276	913
2019	440	232	278	951	440	232	278	951
2020	467	235	281	983	467	235	281	983
2021	484	238	284	1,006	484	238	284	1,006
2022	490	241	285	1,016	490	241	285	1,016
2023	490	244	285	1,019	490	244	285	1,019
2024	490	247	285	1,023	490	247	285	1,023
2025	491	250	285	1,026	491	250	285	1,026
2026	491	254	285	1,030	491	254	285	1,030
2027	491	257	285	1,033	491	257	285	1,033
2028	491	260	285	1,037	491	260	285	1,037
2029	491	264	285	1,040	491	264	285	1,040
2030	491	267	285	1,043	491	267	285	1,043
2031	491	271	285	1,047	491	271	285	1,047

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 Order number 7 in the NCUC Order Approving Integrated Resource Plans and REPS Compliance Plans regarding the 2014 Biennial IRP's, the Base Portfolio EE savings forecast of MW and MWh was compared to the 2014 IRP and the cumulative achievements projected in the 2016 IRP at year 2031 of the forecast are approximately 23.6% higher than the cumulative achievements in the 2014 IRP for the same time period as shown in the table below. Part of this variance is due to an exceptionally strong performance over the last two years, during which time DEP's actual EE accomplishments were 28.5% higher than projected. This near-term variance, as well as the longer-term forecast variance, is due to an aggressive expansion of new and existing programs in the DEP EE portfolio over the past several years, including expansion of the My Home Energy Report into the DEP territory, the Multi Family EE Program, the Energy Efficiency Education Program, the Residential Energy Assessments Program and the Residential Save Energy and Water Kit Program. As mentioned earlier, another factor is the adoption of a revised forecast methodology that better aligns with the method used in the DEC IRP.

Base Portfolio Comparison to 2014 IRP - Gross

Year	2014 IRP Annual MWh Load Reduction: Including measures added in 2014 and beyond	2014 IRP Annual MWh Load Reduction: Including measures added since 2007	2016 IRP Annual MWh Load Reduction: Including measures added in 2016 and beyond	2016 IRP Annual MWh Load Reduction: Including measures added since 2007	% Change from 2014 to 2016 IRP
2014	225,214	1,368,084			
2015	467,656	1,610,527		2,069,991	28.5%
2016	724,195	1,867,066	290,105	2,360,096	26.4%
2017	915,163	2,058,034	556,862	2,626,853	27.6%
2018	1,135,353	2,278,223	820,610	2,890,601	26.9%
2019	1,381,341	2,524,212	1,071,028	3,141,019	24.4%
2020	1,644,724	2,787,595	1,295,170	3,365,161	20.7%
2021	1,918,355	3,061,226	1,519,312	3,589,304	17.3%
2022	2,185,183	3,328,054	1,743,455	3,813,446	14.6%
2023	2,444,434	3,587,305	1,967,597	4,037,588	12.6%
2024	2,695,143	3,838,014	2,191,740	4,261,731	11.0%
2025	2,894,882	4,037,753	2,415,882	4,485,873	11.1%
2026	3,074,232	4,217,103	2,640,024	4,710,015	11.7%
2027	3,230,876	4,373,747	2,864,167	4,934,158	12.8%
2028	3,362,169	4,505,040	3,088,309	5,158,300	14.5%
2029	3,467,037	4,609,908	3,312,451	5,382,442	16.8%
2030	3,531,384	4,674,255	3,536,594	5,606,585	19.9%
2031	3,572,999	4,715,870	3,760,736	5,830,727	23.6%

High EE Savings Projection

The Base Portfolio level EE forecast described above encompasses what the Company expects is achievable given the information about the economic potential and the achievable potential. In addition to this Base Portfolio level EE forecast, DEP also prepared a High Portfolio EE savings projection that assumed that the same types of programs offered in the Base Portfolio, including potential new technologies, can be offered at higher levels of participation provided that additional money is spent on program costs to encourage additional customers to participate. The High Portfolio included in the IRP modeling assumed a 50% increase in participation for all of the Base Portfolio programs, with the exception of programs already designed to reach all eligible participants in the Base Portfolio, including the various behavioral programs (MyHER and Business Energy Reports). In addition, due to changes in the costs and availability of LED lighting technologies, programs in the Base Portfolio related to CFL lighting were assumed to be fully addressed in the Base Portfolio, however, the High Portfolio assumes that additional KWh savings will be captured through LED programs. Finally, the High Portfolio assumed the same “rolling-off” assumption that was included in the Base portfolio. Specifically, that when the EE measures included in the forecast reach the end of their useful lives, the impacts associated with those measures are removed from the future projected EE impacts.

The High Portfolio EE savings projections are higher than the expected achievable savings based on the Market Potential Study. The effort to achieve this High Portfolio would require a substantial expansion of DEP's current Commission-approved EE portfolio. More importantly, significantly higher levels of customer participation would need to be generated.

The table below show the projected High Portfolio savings on both Gross and Net of Free Riders basis without the effects of "rolloff":

High Portfolio MWh Load Impacts of EE Programs

Year	Annual MWh Load Reduction - Gross				Annual MWh Load Reduction - Net			
	Including measures added in 2016 and beyond			Including measures added since 2007	Including measures added in 2016 and beyond			Including measures added since 2007
	Post SB-3 EE	DSDR	Total		Post SB-3 EE	DSDR	Total	
2007-15				2,069,991				1,528,724
2016	428,638	48,723	477,361	2,547,352	346,541	48,723	395,265	1,923,989
2017	833,929	49,325	883,253	2,953,245	671,105	49,325	720,429	2,249,153
2018	1,236,209	49,971	1,286,180	3,356,172	997,332	49,971	1,047,303	2,576,027
2019	1,625,160	50,602	1,675,762	3,745,753	1,312,063	50,602	1,362,665	2,891,389
2020	1,987,836	51,178	2,039,014	4,109,005	1,602,844	51,178	1,654,022	3,182,746
2021	2,350,511	51,670	2,402,182	4,472,173	1,893,161	51,670	1,944,832	3,473,556
2022	2,713,187	52,195	2,765,382	4,835,373	2,183,479	52,195	2,235,674	3,764,399
2023	3,075,862	52,701	3,128,564	5,198,555	2,473,797	52,701	2,526,498	4,055,222
2024	3,438,538	53,349	3,491,887	5,561,878	2,764,115	53,349	2,817,464	4,346,188
2025	3,801,213	53,912	3,855,125	5,925,116	3,054,432	53,912	3,108,344	4,637,068
2026	4,163,889	54,615	4,218,503	6,288,495	3,344,750	54,615	3,399,365	4,928,089
2027	4,526,564	55,277	4,581,841	6,651,832	3,635,068	55,277	3,690,345	5,219,069
2028	4,889,239	56,042	4,945,282	7,015,273	3,925,385	56,042	3,981,428	5,510,152
2029	5,251,915	56,700	5,308,615	7,378,607	4,215,703	56,700	4,272,403	5,801,128
2030	5,614,590	57,432	5,672,023	7,742,014	4,506,021	57,432	4,563,453	6,092,177
2031	5,977,266	58,236	6,035,502	8,105,493	4,796,338	58,236	4,854,575	6,383,299

At this time, there is significant uncertainty in the development of new technologies that will impact the level of EE achievement from future programs and/or enhancements to existing programs, as well as in the ability to secure high levels of customer participation, to risk including the high EE savings projection in the base assumptions for developing the 2016 IRP. DEP expects that over time, as EE programs are implemented, the Company will continue to gain experience and evidence on the viability of the level of EE achieved given actual customer participation. As information becomes available on actual participation, technology changes, and EE achievement, then the EE savings forecast used for integrated resource planning purposes will be revised in future IRP's to reflect the most realistic projection of EE savings.

Programs Evaluated but Rejected

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

Looking to the Future - Grid Modernization (Smart Grid Impacts)

Duke Energy Progress' Distribution System Demand Response (DSDR) program is an Integrated Volt-Var Control (IVVC) program that better manages 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 during peak conditions.

Discontinued Demand Side Management and Energy Efficiency Programs

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

- Residential Energy Efficient Benchmarking Program – The NCUC approved terminating this program in December 2014, at which time it also approved the My Home Energy Report (MyHER) as a new program.

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://www.e-smartonline.net/safeelectricity/.

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 has not discontinued any consumer education programs since the last biennial Resource Plan filing.

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

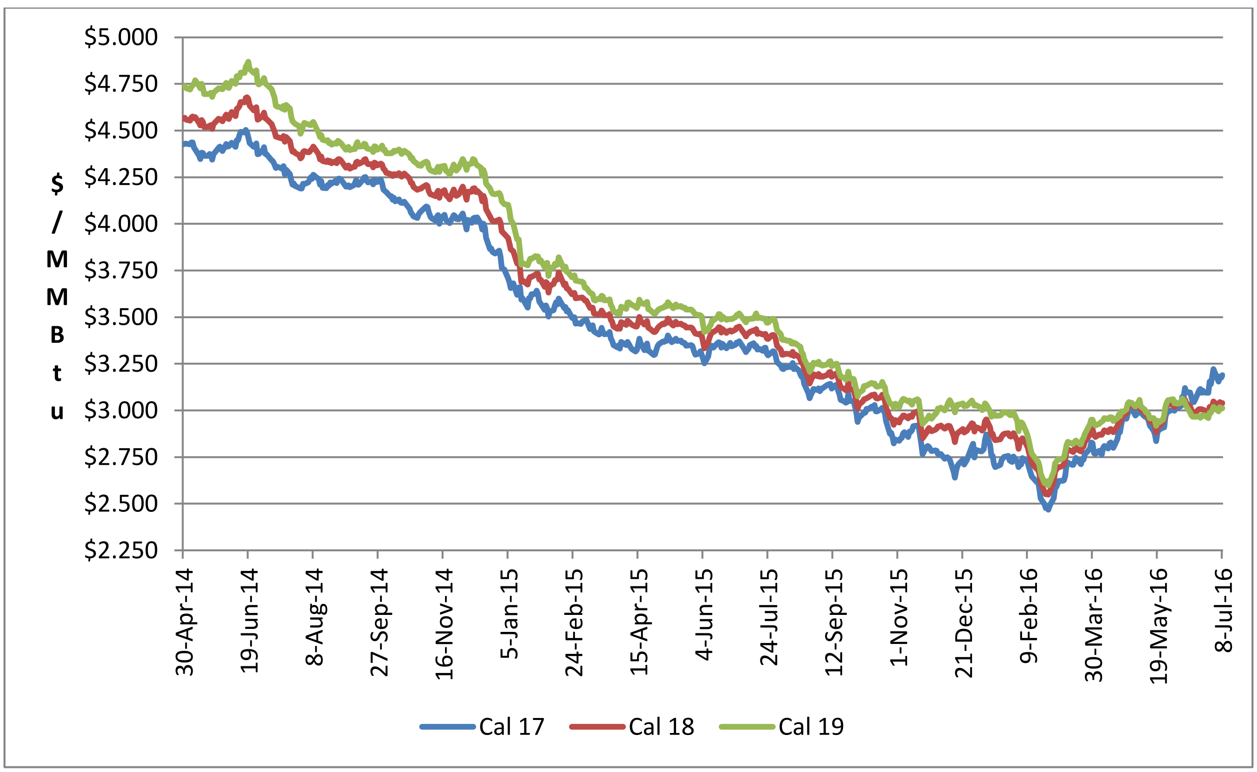
During 2015, spot Henry Hub natural gas prices averaged approximately $2.60 per million BTU (MMBtu) and U.S. lower-48 net dry production averaged approximately 72 billion cubic feet per day (BCF/day). For 2016, natural gas spot prices at the Henry Hub averaged approximately $2.27 in January 2016. Henry Hub spot pricing decreased throughout the remaining winter months and reached a low of approximately $1.485 per MMBtu on March 5, 2016. The decline in short-term spot prices during the first quarter of 2016 were driven by both fundamental supply and demand factors.

Average daily U.S. net dry production levels of approximately 72.7 BCF/day in the first quarter of 2016 were relatively comparable with 2015 net dry production. Storage ended the winter withdrawal season at a record high of 2.47 per trillion cubic feet (TCF) on March 31, 2016. Lower-48 U.S. demand in the first quarter of 2016 was lower than normal due to the mild winter weather which lowered residential heating needs.

Summer 2016 spot natural gas prices have increased from the March 2016 lows outlined previously. The Henry Hub spot price settled in a range between approximately $2.65 to $2.85 per MMBtu in mid-July 2016. Working gas in storage remains above the 5 year average and storage balances from a year ago, although the surplus has declined over the last few months with higher gas generation burns and declining overall net dry gas production which as of August 15, 2016 is approximately 71.4 BCF/day. Observed average NYMEX Henry Hub prices for the winter period November 2016 through March 2017 have increased along with the overall market to approximately $3.09 per MMBtu from the lows observed in late February 2016. Although predicting actual storage balances at the end of the typical injection season is not possible, current projections are roughly 3.8 to 3.9 TCF of working gas in storage at the end of the injection season.

Natural gas consumption is expected to remain strong through the remainder of 2016 and 2017, due primarily to increases in electric power usage. Per the EIA's short-term energy outlook released on July 12, 2016, this year is forecasted to be a record-setting year for gas consumption by power generators. Gas generation is forecasted to exceed coal for the first time annually and account for approximately 34% of U.S. electricity. The EIA estimates that total natural gas production has decreased approximately 1 BCF/day from February 2016 to June 2016 as the market is responding to lower market prices. Producers are right sizing their well production and cutting capex in response to lower spot and forward natural gas prices. With advanced drilling techniques, producers appear able to adjust drilling programs in response to changing market prices to shorten or extend the term of the producing well. According to Baker Hughes, as of July 15, 2016 the U.S. Natural Gas rig count was at 89. This is down from 218 natural gas last year at the same time. This represents a 19 year low in the gas rig count.

In addition to the trends in shorter term natural gas spot price levels for 2016, in late February 2016, the observed forward market prices for the periods of 2017 through 2020 declined to approximately $2.58 per MMBtu. Prices have increased over the last few months from these historical low forward price levels to approximately $3.03 per MMBtu as of late July 2016. This is illustrated in the graph below.



Looking forward, the forward 5 and 10 year observable market curve are at $3.06 and $3.37 per MMBtu, respectively as of the July 21, 2016 close. In addition, as of the close of business on July 8, 2016, the one(1), three(3) and five(5) years strips were all approximately $3.07 per MMBtu. As illustrated with these price levels and relationships, the forward NYMEX Henry Hub price curve is extremely flat with the periods of 2018 and 2019 currently trading at discounts to 2017 prices. The gas market is expected to remain relatively stable due to an improving economic picture which may provide supply and demand to further come into balance. . As noted above, demand from the power sector for 2016 is expected to be higher than coal generation due to 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 through 2020 timeframe. Lastly, although the outcome and timing is uncertain given the current legal status of the Clean Power Plan, there could be additional gas demand as a result of the implementation of the previously announced EPA requirement to reduce carbon emissions.

The long-term fundamental gas price outlook continues to be little changed from previous 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 approximately 60% of net natural gas production today, which has increased from approximately 38% in 2014. Per the Short-Term EIA outlook dated July 12, 2016, the EIA expects production to rise in the second half of 2016 and 2017 in response to forecasted increases in prices and liquefied natural gas (LNG) exports. Additionally, the EIA forecasts the United States transitioning from a net importer of 1.3 TCF of natural gas in 2013 to a net exporter in 2017. Overall, the EIA expects marketed natural gas to rise by approximately 1.7% for the balance of 2016 and by 4.3% by the end of 2017.

The US power sector still represents the largest area of potential new gas demand, but increased usage is expected to be somewhat volatile as generation dispatch is sensitive to price. Looking forward, economic dispatch competition is expected to continue between gas and coal, although there has been some permanent loss in overall coal generation due to the number of coal unit retirements. Overall declines in energy consumption tend to result from the adoption of more energy-efficient technologies and policies that promote energy efficiency.

In order to ensure adequate natural gas supplies, transportation and storage, the company has gas procurement strategies 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. With respect to storage and transportation needs, the company has continued to add incremental firm pipeline capacity and gas storage as its gas generation fleet has grown. The company will continue to evaluate competitive options to meet its growing need for gas pipeline infrastructure as the gas generation fleet grows.

Coal

On average, the 2016 Duke fundamental outlook for coal prices is lower than the 2015 outlook. The power sector accounted for 90.5 % of total demand for coal in 2015, equivalent to 772 million tons of burn. The main determinants of power sector coal demand are natural gas prices, electricity demand growth, and non-fossil electric generation, namely nuclear, hydro, and renewables.

Low natural gas prices continue to exert extreme pressure on the coal fleet resulting in the reduction of coal's competitiveness across virtually all basins and caused generator coal stocks to reach near-term highs. Coal shipments to generators will be even lower than actual burn as these high inventory levels are worked down, a process that could take about two years.

Annual electric load growth, inclusive of energy efficiency impacts, is roughly 1%. The U.S. Supreme Court granted a stay, halting implementation of the EPA's Clean Power Plan pending the resolution of legal challenges to the program in court. Though stayed, the CPP makes retention of coal capacity less desirable. The fundamental outlook anticipates the eventual implementation of CPP beginning in 2022, resulting in a long-term decline in power generation from coal. The coal fired power plants projected to retire during the forecast period burned almost 60 million tons of coal during 2015 which represents approximately 8% of the total 2015 burn. Growth in renewable generation also contributes to the decline in coal demand.

Exports of both thermal and metallurgical coals have been hurt by the strength of the US dollar coupled with the slowing growth of the Chinese economy. In addition, China has implemented import tariffs to protect their domestic coal production.

Finally, the coal industry is in the midst of unprecedented restructuring. It is uncertain how responsive either producers or transporters of coal will be if faced with unexpected periods of increased demand.

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.

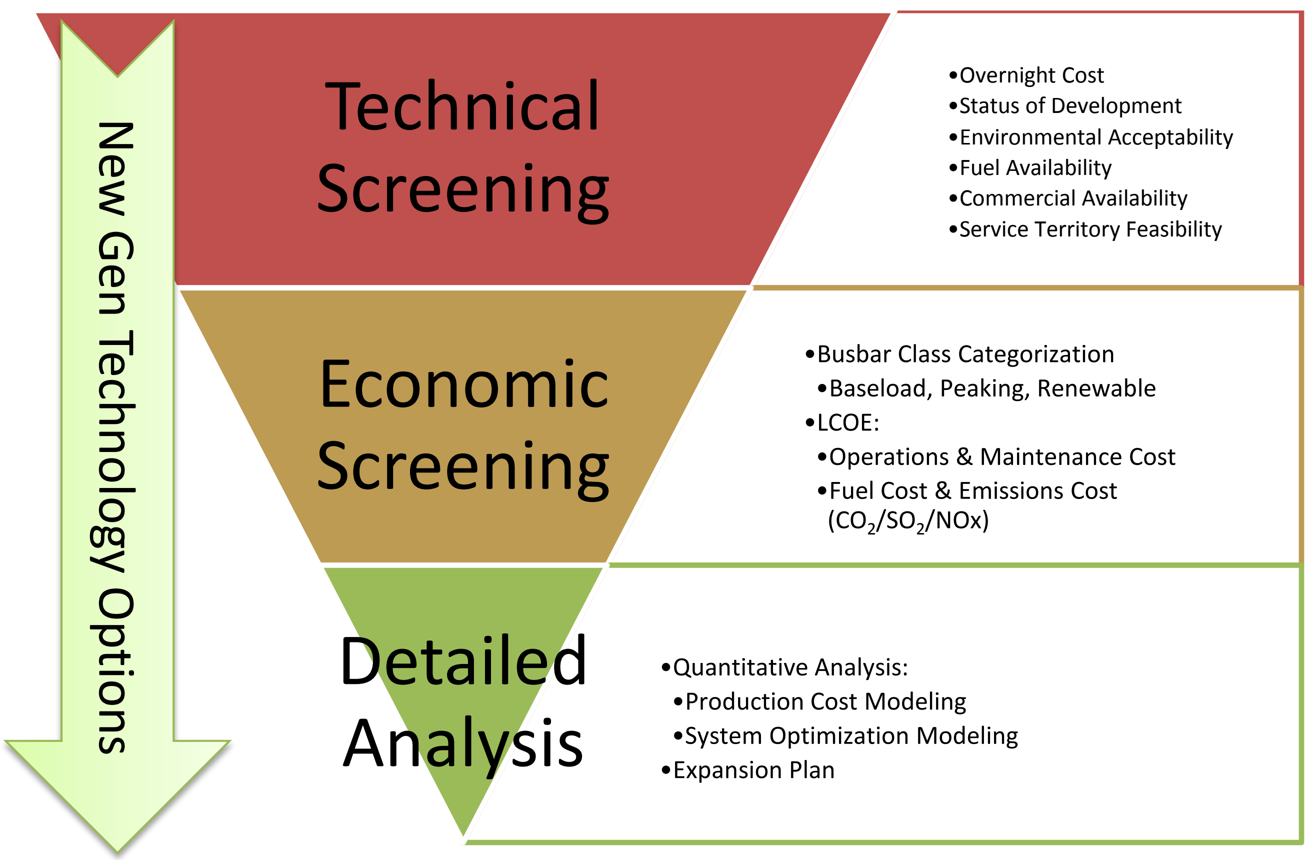
As fuel with a low cost basis is used and lower-priced legacy contracts are replaced with contracts at higher market prices, nuclear fuel expense is expected to increase in the future. Although the costs of certain components of nuclear fuel are expected to increase in future years, nuclear fuel costs 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.

New Generation Technologies Screening 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.

- **Pumped Storage Hydropower (PSH)** is the only conventional, mature, commercial, utility-scale electricity storage option available currently. This technology consumes off-peak electricity by pumping water from a lower reservoir to an upper reservoir. When the electric grid needs more electricity and when electricity prices are higher, water is released from the upper reservoir. As the water flows from the upper reservoir to the lower reservoir, it goes through a hydroelectric turbine to generate electricity. Many operational pumped storage hydropower plants are providing electric reliability and reserves for the electric grid in high demand situations. PSH can provide a high amount of power because its only limitation is the capacity of the upper reservoir. Typically, these plants can be as large as 4,000 MW, and have an efficiency of 76% - 85% Electric Power Research Institute (EPRI, 2012). Therefore, this technology is effective at meeting electric demand and transmission overload by shifting, storing, and producing electricity. This is important because an increasing supply of intermittent renewable energy generation such as solar will cause challenges to the electric grid. PSH installations are greatly dependent on regional geography and face several challenges including: environmental impact concerns, a long permitting process, and a relatively high initial capital cost. Duke Energy currently has two PSH assets on the DEC system, Bad Creek Reservoir and Jocassee Hydro with an approximate combined generating capacity of 2,140MW.

- **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. Traditional systems require a suitable storage site, commonly underground where the compressed air is stored and later used to boost the output of a gas turbine. 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, especially in the

Carolinas. However, above-ground compressed air energy storage (AGCAES) technologies are under development but at a much smaller scale, approximately 0.5 - 20MW. Several companies have attempted to develop cost effective CAES systems using above ground storage tanks. Most attempts to date have not been commercially successful, but their development is being monitored.

- **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. Licensing for SMR's has not been approved by the NRC at present. 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 projects for potential consideration and evaluation for future resource plans as they provide an emission free source of fuel diverse, flexible generation.

- **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 viable/available for utility-scale application.

- **Supercritical CO_2 Brayton Cycle** is of increasing interest; however, the technology is not mature or ready for commercialization. Several pilots are underway and Duke Energy will continue to monitor their development as a potential source of future generation needs.

- **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 in the United States. This technology remains expensive even with the five year tax credit extension granted in December 2015 and has yet to actually be constructed anywhere in the United States. Pioneer wind farm is the first to "break water" off the coast of Rhode Island. Federal waters have not yet been released for wind turbine farm siting; however, state waters are within the rights of the State to exercise jurisdiction. Rhode Island's Block Island is within the 3-mile State waters jurisdiction but strategically located in a manner to gain enough available wind resource to support its economic feasibility. Pioneer is a 30MW demonstration that will utilize five, 6 MW Alstom wind turbines and is expected to be operational by year end 2016. The U.S. Department of the Interior's Bureau of Ocean Energy Management (BOEM) has held several auctions for offshore lease. These sites will be utilized to collect marine and wind data for potential future development of an offshore wind farm.

- **Solar Steam Augmentation** systems utilize solar thermal energy to supplement a Rankine steam cycle such as that in a fossil generating plant. The supplemental steam could be integrated into the steam cycle and support additional MW generation similar in concept to the purpose of duct firing a heat recovery steam generator. This technology, although attractive has several hurdles yet to clear, including a clean operating history and initial capital cost reductions. This technology is very site specific and Duke Energy will continue to monitor developments in the area of steam augmentation.

A brief explanation of the technology additions for 2016 and the basis for their inclusion follows:

- **Addition of Combined Heat & Power (CHP) to the IRP**

  Combined Heat and Power systems, also known as cogeneration, generate electricity and useful thermal energy in a single, integrated system. CHP is not a new technology, but an approach to applying existing technologies. Heat that is normally wasted in conventional power generation is recovered as useful energy, which avoids the losses that would otherwise be incurred from separate generation of heat and power. CHP incorporating a CT and heat recovery steam generator (HRSG) is more efficient than the conventional method of producing usable heat and power separately via a gas package boiler.

Duke Energy is exploring and working with potential customers with good base thermal loads on a regulated Combined Heat and Power offer. The CHP asset will be included as part of Duke Energy's IRP as a placeholder for future projects as described below. The steam sales are credited back to the revenue requirement of the projects to reduce the total cost of this generation grid resource. Along with the potential to be a competitive cost generation resource, CHP can result in CO_2 emission reductions, deferral of T&D expenses, and present economic development opportunities for the state.

Duke Energy has publically announced its first CHP project, a 20 MW (summer) investment at Duke University. We are currently working with other industrial, military and Universities for future project expansions.

- **Addition of Battery Storage to the IRP**

Energy storage solutions are becoming an ever growing necessity in support of grid stability at peak demand times and in support of energy shifting and smoothing from renewable sources. Energy Storage in the form of battery storage is becoming more feasible with the advances in battery technology (Tesla low-cost Lithium-ion battery technology) and the reduction in battery cost; however, their uses (even within Duke Energy) have been concentrated on frequency regulation, solar smoothing, and/or energy shifting from localized renewable energy sources with a high incidence of intermittency (i.e. solar and wind applications).

Duke Energy has several projects in operation since 2011, mainly in support of regulating output voltages/frequencies from renewable energy sources to the grid. This includes projects as large as the Notrees Battery Storage project (36 MW) which supports a wind farm down to the smaller 250 kW Marshall Battery Storage Project which supports a 1.2 MW solar array. Additional examples include the Rankin Battery Storage Project (402 kW), the McAlpine Community Energy Storage Project (24 kW), McAlpine Substation Energy Storage Project (200 kW), and a 2 MW facility on Ohio's former Beckjord Station grounds. Each of these applications supports frequency regulation, solar smoothing, or energy shifting from a local solar array. These examples are only a few in support of a growing trend of coupling Battery Storage with an intermittent renewable energy source such as solar or wind in an effort to stabilize output and increase a facility's (renewable plus storage) net capacity factor.

Beginning in 2016, Distributed Energy Resources, formed an Energy Storage (ES) team to develop a fifteen year battery storage prediction model and begin the development of battery storage deployment plans for the next five year budget cycle. The ES team will focus their five year plan across multiple jurisdictions, however, the first two areas that will most likely provide deployment sites are Duke Energy Indiana (DEI) (substation utility scale application) and western NC, Asheville Regional area (130kV distribution circuit assessment) in DEP. Regional battery storage modeling is proceeding in 2016 to establish battery system sites, use case designs and cost/benefit analysis. Regulatory approvals and cost recovery development will play a key role in the timing of full operational battery system deployment.

Economic Screening

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

This screening curve analysis model includes the total costs associated with owning and maintaining a technology type over its lifetime and computes a levelized $/kW-year value over a range of capacity factors. The Company repeats this process for each supply technology to be screened resulting in a family of lines (curves). The lower envelope along the curves represents the least costly supply options for various capacity factors or unit utilizations. Some technologies have screening curves limited to their expected operating range on the individual graphs. Lines that never become part of the lower envelope, or those that become part of the lower envelope only at capacity factors outside of their relevant operating ranges, have a very low probability of being part of the least cost solution, and generally can be eliminated from further analysis.

The Company selected the technologies listed below for the screening curve analysis. While Clean Power Plan (CPP) regulation may effectively preclude new coal-fired generation, Duke Energy Progress has included ultra-supercritical pulverized coal (USCPC) with carbon capture sequestration (CCS) and integrated gasification combined cycle (IGCC) technologies with CCS of 1400 pounds/net MWh capture rate as options for base load analysis consistent with the pending version of the EPA Clean Power Plan for new coal plants. Additional detail on the expected impacts from EPA regulations to new coal-fired options is included in Appendix G. 2016 additions include Combined Heat and Power as a base load technology and Lithium ion Battery Storage as a renewable technology.

Dispatchable (Summer Ratings)

- Base load – 782 MW Ultra-Supercritical Pulverized Coal with CCS
- Base load – 557 MW 2x1 IGCC with CCS
- Base load – 2 x 1,117 MW Nuclear Units (AP1000)
- Base load – 576 MW – 1x1x1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Base load – 1,160 MW – 2x2x1 Advanced Combined Cycle (Inlet Chiller and Fired)
- Base load – 20 MW – Combined Heat & Power (CHP)
- Peaking/Intermediate – 166 MW 4 x LM6000 Combustion Turbines
- Peaking/Intermediate – 201 MW 12 x Reciprocating Engine Plant
- Peaking/Intermediate – 870 MW 4 x 7FA.05 Combustion Turbines
- Renewable – 2 MW / 8 MWh Li-ion Battery
- Renewable – 5 MW Landfill Gas

Non-Dispatchable

- Renewable – 150 MW Wind - On-Shore
- Renewable – 5 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 Management & Construction, Emerging Technologies, and Generation & Regulatory Strategy. The following external sources may also be utilized: proprietary third-party engineering studies, the Electric Power Research Institute 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, O&M costs 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 nitrogen oxides ($NO_{X)}$, sulfur dioxide ($SO_{2)}$, 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 (i.e. No Carbon Tax, Carbon Tax, System Carbon Mass Cap).

Screening Results

The results of the screening within each category are shown in the figures below. Results of the baseload screening show that natural gas combined cycle generation is the least-cost base load resource. With lower gas prices, larger capacities and increased efficiency, natural gas combined cycle units have become more cost-effective at higher capacity factors in all carbon scenario screening cases (i.e. No Carbon Tax, Carbon Tax, System Carbon Mass Cap). Although CHP is competitive with CC at the upper end of the capacity range, it is site specific, requiring a local steam and electrical load. The baseload curves also show that nuclear generation may be a cost effective option at high capacity factors with CO_2 costs included. Carbon capture systems have been demonstrated to reduce coal-fired CO_2 emissions to levels similar to natural gas and will continue to be monitored as they mature; however, their current cost and uncertainty of safe, reliable storage options has limited the technical viability of this technology.

The peaking/intermediate technology screening included F-frame combustion turbines, fast start aero-derivative combustion turbines, and fast start reciprocating engines. 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 or reciprocating engines. Reciprocating engine plants offer the lowest heat rates and fastest start times among simple cycle options. In addition, the recent strength of the U.S. dollar compared to the Euro has led to reduced costs for reciprocating engines imported from Europe. However, the volatility of the exchange rates should be considered for the generic selection of this technology, especially with the potential British withdrawal from the European Union (EU).

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.

Centralized generation, as depicted above, will remain the backbone of the grid for Duke Energy in the long-term; however, in addition it is likely that distributed generation will begin to share more and more grid responsibilities over time as technologies such as energy storage increase our grid's flexibility.

The screening curves are useful for comparing costs of resource types at various capacity factors but cannot be solely 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

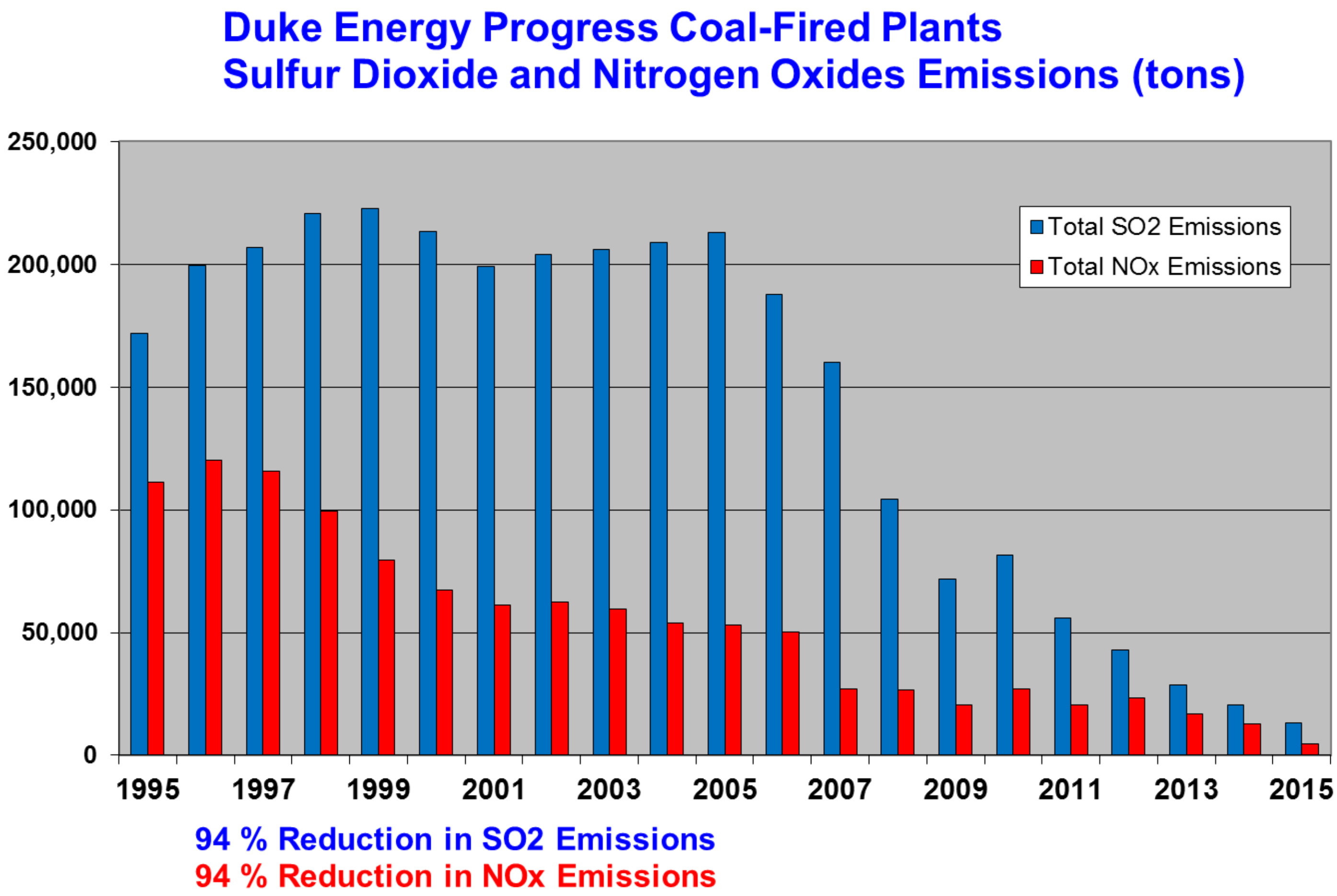
Duke Energy Progress, which is subject to the jurisdiction of Federal agencies including the Federal Energy Regulatory Commission EPA, and the NRC, as well as State commissions and agencies, is potentially impacted by State and Federal legislative and regulatory actions. This section provides a high-level 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. The following is brief summary of the major air related federal regulatory programs that are currently impacting or that could impact Duke Energy Progress operations in South Carolina.

The chart below shows the significant downward trend in both NO_x and SO_2 emissions through 2015 as a result of actions taken at Duke Energy Progress facilities.

Chart G-1 DEP NO_X and SO_2 Emissions



The following is brief summary of the major air related federal regulatory programs that are currently impacting or that could impact Duke Energy Progress operations in South Carolina.

Cross-State Air Pollution Rule (CSAPR)

In August, 2011 the EPA finalized the Cross-State Air Pollution Rule (CSAPR). The CSAPR established state-level caps on annual SO_2 and NOx emissions and ozone season NOx emissions from electric generating units (EGUs) across the Eastern U.S., including South Carolina. The CSAPR was set up as a two-phase program with Phase I taking effect in 2012 and Phase II taking effect in 2014. Legal challenges to the rule resulted in Phase I implementation being delayed until 2015 and Phase II implementation being delayed until 2017. Duke Energy Progress has been complying with Phase I of the CSAPR and is well positioned to comply with Phase II beginning in 2017.

The CSAPR ozone season NOx program was designed to address interstate transport for the 80 parts per billion (ppb) ozone standard that was established in 1997. In 2008 the EPA lowered the ozone standard to 75 ppb. In late 2015 the EPA proposed a rule, referred to as the CSAPR Update Rule, to revise Phase II of the CSAPR ozone season NOx program to address interstate transport for the 75 ppb standard. EPA proposed to completely eliminate the CSAPR ozone season NOx cap for South Carolina. The EPA has indicated that it plans to finalize the rule in the summer of 2016. Duke Energy Progress cannot predict the outcome of this rulemaking, however, regardless of the outcome, Duke Energy Progress does not anticipate any adverse impact to its operations in South Carolina given the fact that it operates few affected sources in the state.

Mercury and Air Toxics Standards (MATS) Rule

In March 2011 the EPA proposed the Mercury and Air Toxics Standards (MATS) rule to regulate emissions of mercury and other hazardous air pollutants from coal-fired EGUs. The rule establishing unit-level emission limits for mercury, acid gases, and non-mercury metals, was finalized in February, 2012. Duke Energy Progress has retired all of its coal-fired EGUs in South Carolina so it does not operate any EGUs in South Carolina that are affected by the MATS rule.

National Ambient Air Quality Standards (NAAQS)

8-Hour Ozone NAAQS

In October, 2015, EPA finalized a revision to the 8-Hour Ozone NAAQS, lowering it from 75 to 70 ppb. State recommendations to EPA regarding area designations under the 70 ppb standard are due to EPA by October 1, 2016. The EPA expects to finalize area designations by October 1, 2017 based on 2014-2016 air quality. Attainment dates for any areas designated nonattainment will depend on the area's nonattainment classification, but will not be earlier than October, 2020.

The 70 ppb ozone standard is being challenged in court by numerous parties. Some are challenging the standard as being too low, while others are challenging the standard as not being low enough. Duke Energy Progress cannot predict the outcome of the litigation or assess the potential impact of the lower standard on future operations in South Carolina at this time given the uncertainty surrounding area designations.

SO_2 NAAQS

On June 22, 2010, EPA finalized a rule establishing a 75 ppb 1-hour SO_2 NAAQS. Since then, EPA has completed two rounds of area designations, neither of which resulted in any areas in South Carolina being designated nonattainment.

In August, 2015, the EPA finalized its Data Requirements Rule which established requirements for state air agencies to characterize SO_2 air quality levels around certain EGUs using ambient air quality monitoring or air quality modeling. The Data Requirements Rule also laid out the timeline for state air agencies to complete air quality characterizations and submit the information to EPA, and for EPA to finalize area designations. Duke Energy Progress has retired all of its coal-fired EGUs in South Carolina and therefore does not operate any EGUs in South Carolina around which the state must characterize SO_2 air quality.

Fine Particulate Matter ($PM_{2.5}$) NAAQS

On December 14, 2012, the EPA finalized a rule establishing a 12 microgram per cubic meter annual $PM_{2.5}$ NAAQS. The EPA finalized area designations for this standard in December 2014. That designation process did not result in any areas in South Carolina being designated as a nonattainment area.

Greenhouse Gas Regulation

On August 3, 2015, the EPA finalized a rule establishing carbon dioxide (CO_2) new source performance standards for pulverized coal (PC) and natural gas combined cycle (NGCC) EGUs that initiated or that initiates construction after January 8, 2014. The EPA finalized emission standards of 1,400 lb CO_2 per gross MWh of electricity generation for PC units and 1,000 lb CO_2 per gross MWh for NGCC units. The standard for PC units can only be achieved with carbon capture and sequestration (CCS) technology. Duke Energy Progress views the EPA rule as barring the development of new coal-fired generation because CCS is not a demonstrated and available technology for applying to PC units. Duke Energy Progress considers the standard for NGCC units to be achievable. Numerous parties have filed petitions with the U.S. Court of Appeals for the District of Columbia ("D.C. Circuit") challenging the EPA's final emission standard for new PC units.

On August 3, 2015, the EPA finalized the Clean Power Plan (CPP), a rule to limit CO_2 emissions from existing fossil fuel-fired EGUs (existing EGUs are units that commenced construction prior to January 8, 2014). The CPP requires states to develop and submit to EPA for approval a state implementation plan designed to achieve the required CO_2 emission limitations. The CPP required states to submit an initial plan by September 6, 2016, and a final plan by September 6, 2018. The CPP established two rate-based compliance pathways and two mass-based compliance pathways for states to choose from when developing their state implementation plans. At this time it is unknown which approach the state of South Carolina might select for its implementation plan. The EPA would review and approve or disapprove state plans within 12 months of receipt. The CPP required emission limitations to take effect beginning in 2022 and get gradually more stringent through 2030.

The CPP does not directly impose regulatory requirements on Duke Energy Progress. An approved South Carolina state implementation plan would establish the regulatory requirements that would apply to Duke Energy Progress. If South Carolina were not to submit an approvable plan, EPA would impose a federal implementation plan on affected Duke Energy Progress EGUs to achieve the required CO_2 emission limitations.

Numerous legal challenges to the CPP were filed with the DC Circuit. Many petitioners also asked the DC Circuit to stay the rule until questions about its legal status get resolved. The DC Circuit denied motions to stay the CPP, but shortly thereafter the Supreme Court granted a stay of the rule, halting implementation of the CPP through any final decision in the case by the Supreme Court. This means the CPP has no legal effect, and EPA cannot enforce any of the deadlines or rule requirements while the stay is in place.

Briefing of the case before the D.C. Circuit was completed in April, 2016. Oral arguments before the full D.C. Circuit are scheduled for September 27, 2016. A decision by the D.C. Circuit will most likely be issued in early 2017. It is expected that the losing parties in that decision will seek Supreme Court review, and it is likely that the Supreme Court will grant review. In this event, final resolution of the case might not occur until sometime in 2018.

Generally, the CPP is designed to cause the replacement of coal-fired generation with generation from natural gas and renewable energy sources. Duke Energy Progress has retired all of its coal-fired EGUs in South Carolina. Therefore, if the CPP is ultimately upheld by the courts and implementation goes forward, Duke Energy Progress would not expect the rule to have a measurable impact on its operations in South Carolina.

One of the uncertainties surrounding the CPP is the implementation schedule that would apply if the CPP is found to be lawful. In prior instances where a final rule has been stayed but eventually found to be lawful, all implementation dates have been delayed by at least the number of days the stay was in place. While an exact implementation schedule for the CPP under such an outcome is uncertain, what does seem certain is that if the CPP is found to be lawful, the schedule for implementation will be delayed from what is in the final rule.

Water Quality and By-product Issues

CWA 316(b) Cooling Water Intake Structures

Federal regulations implementing §316(b) of the Clean Water Act (CWA) for existing facilities were published in the Federal Register on August 15, 2014 with an effective date of October 14, 2014. 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 greater from rivers, streams, lakes, reservoirs, estuaries, oceans, or other waters of the United States. All Duke Energy nuclear fueled, coal-fired and combined cycle stations, in North and South Carolina are affected sources, with the exception of Smith Energy[12].

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 fps; or
— Install modified traveling water screens and optimize performance through a two-year

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

study; or

- Demonstrate a system of technologies, practices, and operational measures are optimized to reduce impingement mortality; or
- Demonstrate the impingement latent mortality is reduced to no more than 24% annually based on monthly monitoring.

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

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

The rule requires facilities with a NPDES permit that expire after July 14, 2018 to submit all necessary 316(b) reports with the renewal application. For facilities with a NPDES permit that expire prior to July 14, 2018 or are in the renewal process, the state permitting agency is allowed to establish an alternate submittal schedule. We expect submittals to be due in the 2018 to 2021 timeframe and intake modifications, 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

Federal regulations revising the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (ELG Rule) were published in the Federal Register on November 3, 2015 with an effective date of January 4, 2016. While the ELG Rule is applicable to all steam electric generating units, waste streams affected by these revisions are generated at DEP’s coal-fired facilities. The revisions prohibit the discharge of bottom and fly ash transport water, and flue gas mercury control wastewater, and establish technology based limits on the discharge of wastewater generated by Flue Gas Desulfurization (FGD) systems, and leachate from coal combustion residual landfills and impoundments. The rule, also, establishes technology based limits on gasification wastewater, but this waste stream is not generated at any of the DEP facilities. The new limits must be incorporated into the applicable stations' National Pollutant Discharge Elimination System permit based on a date determined by the permitting authority that is as soon as possible beginning November 1, 2018, but no later than December 31, 2023, with the exception of limits for CCR leachate, which are effective upon issuance of the permit after the effective date of the rule. For discharges to publically owned treatment works (POTW), the limits must be met by November 1, 2018.

The extent to which the rule will affect a particular steam electric generating unit will depend on the treatment technology currently installed at the station. A summary of the impacts are as follows:

- Fly Ash Transport Water: All DEP coal-fired units either handling fly ash dry during normal operation or are scheduled to be retired prior to the compliance date. However, to ensure fly ash is handled dry without disruptions to generation, dry fly ash reliability projects are being completed.

- Bottom Ash Transport Water: All DEP coal-fired units, except for Asheville and Mayo Steam Station, will be required to install a closed-loop or a dry bottom ash handling system.

- FGD Wastewater: All DEP coal-fired units, except for Mayo Steam Station will be required to upgrade or completely replace the existing FGD wastewater treatment system.

- CCR Leachate: The revised limits for CCR leachate from impoundments and landfills are the same as the previous existing limits for low volume waste. Potential impacts are being evaluated on a facility-specific basis.

Coal Combustion Residuals

In January 2009, following Tennessee Valley Authority's 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 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 proposed the CCR rule for notice and comment and then published the final rule on April 17, 2015. The CCR rule regulates CCR as a nonhazardous waste under Subtitle D of RCRA and allows for beneficial use of CCR with some restrictions. The effective date of the rule was October 19, 2015.

The CCR rule applies to all new and existing landfills, new and existing surface impoundments receiving CCR and existing surface impoundments that are no longer receiving CCR but contain liquid located at stations currently generating electricity (regardless of fuel source). The rule establishes requirements regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to ensure the safe disposal and management of CCR.

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]

Table H-3 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 generation's central role in DEP's NC REPS compliance plan and SC DERS.

Below is a summary of the interconnection queue as of June 30, 2016:

Utility	FacilityState	Energy Source Type	Number of Pending Projects	Pending Capacity (MW AC)
DEP	**NC**	Biomass	4	50.8
		Diesel	7	3.2
		Natural Gas	2	530.0
		Other	2	1.2
		Solar	380	2654.5
DEP	**NC Total**		**395**	**3239.6**
	SC	Diesel	1	0.4
		Solar	101	1220.9
DEP	**SC Total**		**102**	**1221.3**
DEP Total			**497**	**4460.9**

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

APPENDIX I: TRANSMISSION PLANNED OR UNDER CONSTRUCTION

This appendix lists the planned transmission line additions. A discussion of the adequacy of DEP's transmission system is also included. Table I-1 lists the transmission line projects that are planned to meet reliability needs.

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
2018	Sutton Plant	Castle Hayne North Line	239	115	Upgrade
2018	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
2020	Jacksonville	Grants Creek	1195	230	New
2020	Newport	Harlowe	681	230	New

DEP Transmission System Adequacy

Duke Energy Progress (DEP) 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 projected 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 and South Carolina Interconnection Procedures.

SERC 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 the fall of 2014. 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 ensures that DEP's transmission system continues to provide reliable service to its native load and firm transmission customers.

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

The following table cross-references IRP regulatory requirements for SC Code Ann. § 58-37-10 in South Carolina and identifies where those requirements are discussed in the IRP.

Requirement	Location	Reference	Updated
B. REQUIREMENTS FOR THE DEVELOPMENT AND COMPOSITION OF THE IRP FILING (Cont.)			
1. Environmental costs are to be considered on a monetized basis where sufficient data is available. Those environmental costs that cannot be monetized must be addressed on a qualitative basis within the planning process. Environmental costs are to be considered within the IRP to the extent that they impact. the utility's specific system costs such as meeting existing regulatory standards and such standards as ran be reasonably anticipated to occur. The term "reasonably anticipated to occur" refers to standards that are in the process of being developed and are known to be forthcoming but are not finalized at the time of analysis. This does not mean that. the utility is prohibited from incorporating factors which go beyond the above definition. Should the utility feel that other factors (environmental or other) are important and need to be incorporated within the planning process, it needs to justify within the IRP the basis for inclusion. a. Environmental costs should be monetized and included within the planning process whenever possible. To the extent that environmental costs cannot be monetized the utility must consider them on a qualitative basis in developing the plan. The same guideline applies to relevant utility and customer costs. b. Each utility must provide the general environmental standards applicable to each supply-side option and explain the impact of each supply-side option on compliance with the standards. To the extent feasible each utility should seek to identify on a quantitative basis the impact of demand-side options on the environment (i.e. reduced pollutant emissions, reduced waste disposal, increased noise pollution, etc.) Such impacts ran be reflected on a qualitative basis when quantitative information is not available. c. Each utility should identify and monetize, to the extent possible, the cost of compliance for existing and projected supply-side options.	Ch. 8, App A	SC § 58-37-10	Yes

Requirement	Location	Reference	Updated
2. Each utility must. provide a demand forecast (to include both summer and winter peak demand) and an energy forecast. Forecasting requirements for the IRP filing: a. Forecast must incorporate explicit treatment of demand-side resources. b. Forecasting methodologies should seek to incorporate "end-use" modeling techniques where they are appropriate. End-use and econometric modeling techniques can be combined where appropriate to seek accuracy while being able to address the impacts of demand-side options. c. The IRP filing must incorporate energy and peak demand forecasts that include an explanation of the forecasting methodology and modeling procedures. d. The IRP filing must incorporate summary statistics for major models; assumptions followed within the forecasting process; projected energy usage by customer class; load factors by customer class; and total system sales. The utility must file this information, either as part of the IRP or as supplemental material to the IRP. e. An analysis must be performed to assess forecast uncertainty. This can consist of a high, most likely, low scenario analysis. f. The utility should periodically test its forecasting methodology for historical accuracy. g. The utility must identify significant changes in forecasting methodology.	Ch. 3, App C	SC § 58-37-10	Yes
3. The IRP filing must include a discussion of the risk associated with the plan (risk assessment). Where feasible the impacts of potential deviations from the plan should be identified.	Ch. 8, App A	SC § 58-37-10	Yes
4. The transmission improvements and/or additions necessary to support the IRP will also be provided within the plan. This includes listing the transmission lines and other associated facilities (125 kv or more) which are under construction or proposed, including the capacity and volt. age levels, locations, and schedules for completion and operation.	App I	SC § 58-37-10	Yes

Requirement	Location	Reference	Updated
5. The plan must incorporate an evaluation and review of the existing demand-side options utilized the utility. It should identify changes in objectives and specifically identify and quantify achievements within each specific program. plan should include a description of each objectives; implementation schedule; achievements to date. An explanation be provided outlining the approaches used to measure achievements and benefits.	Ch. 4, App D	SC § 58-37-10	Yes
6. The IRP filing must identify and discuss any significant studies being conducted by the company on future demand-side and/or supply-side options.	Ch. 4, App D	SC § 58-37-10	Yes
7. The IRP must be flexible to allow for the unknowns and uncertainties that confront the plan. The IRP must have the ability to quickly adapt to changes in a manner consistent with minimizing costs while maintaining reliability.	Ch. 8, App A	SC § 58-37-10	Yes
8. The utilities must incorporate as part of their IRP's a maintenance and refurbishment program of existing units when economically viable and consistent with system reliability and planning flexibility.	App A, App I	SC § 58-37-10	Yes
9. Utilities must adequately consider all cost effective third-party power purchases including firm, unit, etc., consistent with the IRP objective statement. This involves consideration of both interconnected and non-interconnected third-party purchases. The utility will describe any consideration of joint planning with other utilities. The utility will identify all third party power purchase agreements.	App H, App A	SC § 58-37-10	Yes
10. The IRP filing must identify any major problems the utility anticipates that have the potential to impact the success of the plan and the planning process. Strategies which might be invoked to deal with each problem should be identified whenever possible.	App A	SC § 58-37-10	Yes
11. Each utility must demonstrate that the IRP incorporates not only efficient and cost. effective generation resources but also that transmission and distribution system costs are consistent with the minimization of total system costs. Any supporting information can be filed as a supplement to the IRP.	App I	SC § 58-37-10	Yes
12. Each utility must explain and/or describe any technologies included in the IRP.	Ch. 6, App F	SC § 58-37-10	Yes

Requirement	Location	Reference	Updated
13. Each future supply-side option incorporated within the identified. fuel source; anticipated generating capacity; anticipated date of initial construction; anticipated date of commercial operation; etc. provided for each option. Utility shall identify the anticipated location of future supply-side option it is consistent with the utility's proprietary interests.	Exec Summary, Ch. 8, App A	SC § 58-37-10	Yes
14. The IRP must demonstrate that each utility is pursuing those resource options available for less than the avoided costs of new supply-side alternatives. Demand-side options will included in the IRP to the extent they are cost-effective are consistent with the Commission objective statement for the IRP. Utility DSM plans shall give attention to capturing lost opportunity resources. They include those cost effective energy efficiency savings that can only be realized during a narrow time period, such as in new construction, renovation, and in routine replacement of existing equipment.	App D	SC § 58-37-10	Yes

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July 7, 2017

VIA ELECTRONIC FILING

Ms. Jocelyn Boyd, Chief Clerk/Administrator
Public Service Commission of South Carolina
Synergy Business Park, Saluda Building
101 Executive Center Drive
Columbia, SC 29210

Re: Duke Energy Progress, LLC
Update to Darlington Unit 9 Retirement Date
Docket No. 2016-8-E

Dear Ms. Boyd:

I write to notify the Commission and all parties of the updated retirement date for the following combustion turbine ("CT") generating unit in connection with the 2016 Duke Energy Progress, LLC ("DEP") Integrated Resource Plan ("IRP"):

DEP Unit	Capacity	Old Retirement Date	New Retirement Date
Darlington CT Unit 9	65 MW (winter rating)	January 2020	June 30, 2017

The Darlington CT Unit 9 has served DEP customers well over its useful life but, based upon condition and economic evaluations, the Company determined that this unit will no longer provide economic and reliable commercial service to customers, and the unit was retired effective June 30, 2017.

Thank you for your attention to this matter. If you have any questions, please let me know.

Sincerely,

Heather Shirley Smith

Heather Shirley Smith
Deputy General Counsel

cc: Shannon Bowyer Hudson, Esq., Office of Regulatory Staff (email and US Mail)
J. Blanding Holman, IV, Esq., Southern Environmental Law Center (email and US Mail)
Michael K. Lavanga, Esq., Stone Mattheis Xenopoulos & Brew, PC (email and US Mail)
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Rebecca J. Dulin, Senior Counsel, Duke Energy Progress, LLC (email)

BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2016-8-E

In the Matter of:	)	
	)	
Duke Energy Progress, LLC's	)	**CERTIFICATE OF SERVICE**
Intergrated Resource Plan (IRP)	)	
	)	

This is to certify that I, Toni C. Hawkins, a paralegal with the law firm of Sowell, Gray, Robinson, Stepp & Laffitte, LLC, have this day caused to be served upon the person(s) named below the **attached letterdated July 7, 2017 on behalf of Duke Energy Progress, LLC** in the foregoing matter by placing a copy of same in the U.S. Mail addressed as follows:

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Dated at Columbia, South Carolina this 7th day of July, 2017.

Toni C. Hawkins

Toni C. Hawkins