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November 1, 2018

VIA ELECTRONIC FILING

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

Re: Duke Energy Progress, LLC 2018 Integrated Resource Plan

Dear Ms. Boyd:

Pursuant to SC Code § 58-37-40, enclosed for filing is Duke Energy Progress, LLC's ("DEP") 2018 Integrated Resource Plan ("2018 DEP IRP"). In addition to the 2018 DEP IRP being electronically filed with the Commission, we are also hand-delivering bound copies to the Office of Regulatory Staff and the State Energy Office.

Please contact me should you have any questions.

Kind regards,

Sam Wellborn

SJW:tch

Enclosures

cc w/enc: Jeffrey M. Nelson, ORS Chief Legal Officer (via email & hand delivery)
Dawn Hipp, ORS Utility Rates & Services Director (via email)
Anthony James, State Energy Office Director of Energy Policy (via email & hand delivery)
Heather Shirley Smith, Deputy General Counsel (via email)
Rebecca J. Dulin, Senior Counsel (via email)

DUKE ENERGY PROGRESS

DUKE ENERGY PROGRESS

SOUTH CAROLINA INTEGRATED RESOURCE PLAN

2018

PUBLIC

DEP SC 2018 IRP CONTENTS:

ABBREVIATIONS:

10 CFR	Title 10 of the Code of Federal Regulations
AC	Alternating Current
AEO	Annual Energy Outlook
BCFD	Billion Cubic Feet Per Day
CAIR	Clean Air Interstate Rule
CAMA	North Carolina Coal Ash Management Act of 2014
CAMR	Clean Air Mercury Rule
CAPP	Central Appalachian Coal
CC	Combined Cycle
CCR	Coal Combustion Residuals
CCS	Carbon Capture and Sequestration
CECPCN	Certificate of Environmental Compatibility and Public Convenience and Necessity (SC)
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 (NC)
CPRE	Competitive Procurement of Renewable Energy
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
DC	Direct Current
DCA	Design Certification Application
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEI	Duke Energy Indiana
DEK	Duke Energy Kentucky
DEP	Duke Energy Progress
DER	Distributed Energy Resource
DIY	Do It Yourself
DOE	Department of Energy
DOJ	Department of Justice
DSM	Demand-Side Management
EE	Energy Efficiency Programs
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction Contractors
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization

ABBREVIATIONS:

FLG	**Federal Loan Guarantee**
FPS	**Feet Per Second**
GALL-SLR	**Generic Aging Lessons Learned for Subsequent License Renewal**
GEH	**GE Hitachi**
GHG	**Greenhouse Gas**
GWh	**Gigawatt-hour**
HB 589	**North Carolina House Bill 589**
HVAC	**Heating, Ventilation and Air Conditioning**
HRSG	**Heat Recovery Steam Generator**
IA	**Interconnection Agreement**
IGCC	**Integrated Gasification Combined Cycle**
ILB	**Illinois Basin**
ILR	**Inverter Load Ratios**
IRP	**Integrated Resource Plan**
IS	**Interruptible Service**
ISOP	**Integrated Systems and Operations Planning**
IT	**Information Technologies**
ITC	**Investment Tax Credit**
IVVC	**Integrated Volt-Var Control**
JDA	**Joint Dispatch Agreement**
kW	**Kilowatt**
kWh	**Kilowatt-hour**
LCR TABLE	**Load, Capacity, and Reserves Table**
LEED	**Leadership in Energy and Environmental Design**
LED	**Light Emitting Diodes**
LEO	**Legally Enforceable Obligation**
LFE	**Load Forecast Error**
LNG	**Liquified Natural Gas**
LOLE	**Loss of Load Expectation**
MACT	**Maximum Achievable Control Technology**
MATS	**Mercury Air Toxics Standard**
MGD	**Million Gallons Per Day**
MW	**Megawatt**
MWh	**Megawatt-hour**
NAPP	**Northern Appalachian Coal**
NAAQS	**National Ambient Air Quality Standards**
NAP	**Northern Appalachian Coal**
NEMS	**National Energy Modeling Systems**
M&V	**Measurement and Verification**
NC	**North Carolina**
NCCSA	**North Carolina Clean Smokestacks Act**

ABBREVIATIONS:

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**
NERC	**North American Electric Reliability Corp**
NESHAP	**National Emission Standards for Hazardous Air Pollutants**
NO_x	**Nitrogen Oxide**
NES	**Neighborhood Energy Saver**
NPDES	**National Pollutant Discharge Elimination System**
NRC	**Nuclear Regulatory Commission**
NSPS	**New Source Performance Standard**
NYMEX	**New York Mercantile Exchange**
NUREG	**Nuclear Regulatory Commission Regulation**
OATT	**Open Access Transmission Tariff**
O&M	**Operating and Maintenance**
PD	**Power Delivery**
PEV	**Plug-In Electric Vehicles**
PJM	**PMJ Interconnection, LLC**
PMPA	**Piedmont Municipal Power Agency**
PPA	**Purchase Power Agreement**
PPB	**Parts Per Billion**
PROSYM	**Production Cost Model**
PSCSC	**Public Service Commission of South Carolina**
PSD	**Prevention of Significant Deterioration**
PURPA	**Public Utility Regulatory Policies Act**
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**
RICE	**Reciprocating Internal Combustion Engines**
RIM	**Rate Impact Measure**
RPS	**Renewable Portfolio Standard**
RRP	**Refrigerator Replacement Program**
SAE	**Statistical Adjusted End-Use Model**
SAT	**Single-Axis Tracking**
SC	**South Carolina**

ABBREVIATIONS:

SCE&G	**South Carolina Electric & Gas**
SC DER or SC ACT 236	**South Carolina Distributed Energy Resource Program**
SCR	**Selective Catalytic Reduction**
SEPA	**Southeastern Power Administration**
SERC	**SERC Reliability Corporation**
SERVM	**Strategic Energy Risk Valuation Model**
SG	**Standby Generation**
SIP	**State Implementation Plan**
SLR	**Subsequent License Renewal**
SMR	**Small Modular Reactor**
SO	**System Optimizer**
SO_2	**Sulfur Dioxide**
SRP – SLR	**Standard Review Plan for the Review of Subsequent License Renewal**
T&D	**Transmission & Distribution**
TAG	**Technology Assessment Guide**
TRC	**Total Resource Cost**
TVA	**Tennessee Valley Authority**
THE COMPANY	**Duke Energy Progress**
THE PLAN	**Duke Energy Progress Annual Plan**
UEE	**Utility Energy Efficiency**
UG/M^3	**Micrograms Per Cubic Meter**
UCT	**Utility Cost Test**
VACAR	**Virginia/Carolinas**
VAR	**Volt Ampere Reactive**
WERP	**Weatherization and Equipment Replacement Program**
ZELFRS	**Zero – Emitting Load Following Resources**

1. EXECUTIVE SUMMARY

For more than a century, Duke Energy Progress (DEP or the Company) has provided affordable and reliable electricity to customers in South Carolina (SC) and North Carolina (NC) now totaling approximately 1.6 million in number. The Company continues to serve its growing number of customers by planning for future resource needs in the most reliable and economic way possible while using increasingly clean forms of energy to meet those needs.

Historically, each year, as required by the Public Service Commission of South Carolina (PSCSC) and the North Carolina Utilities Commission (NCUC), DEP submits a long-range planning document called the Integrated Resource Plan (IRP). The IRP details potential infrastructure needed to match the forecasted electricity requirements and a reasonable reserve margin to maintain system reliability for our customers over the next 15 years.

The Company files separate IRPs for South Carolina and North Carolina. However, the IRP analyzes the system as one DEP utility across both states including customer demand, energy efficiency (EE), demand-side management (DSM), renewable resources and traditional supply-side resources. As such, the quantitative analysis contained in both the South Carolina and North Carolina filings is identical, while certain sections dealing with state-specific issues such as state renewable standards or environmental standards may be specific to that state's IRP.

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, other regulatory entities, retail customers, wholesale customers, environmental advocates, renewable resource industry groups and the general public.

2018 IRP SUMMARY

Objectives:

The 2018 IRP is the best projection of how the Company's resource portfolio is expected to evolve based on current data and assumptions. This projection may change over time as variables such as the projected load forecasts, fuel price forecasts, federal and state regulations, technology performance and cost characteristics and other outside factors change.

Consistent with the Company's commitment to a smarter energy future, the resource plan presented within this IRP meet the following objectives:

- Improve the environmental footprint of the resource portfolio reducing carbon dioxide (CO_2) emissions by at least 40% from 2005 levels by 2030 with approximately 60% of electricity coming from carbon free clean energy sources.
- Ensure adequate resource reserves are available over the planning horizon to provide reliable electric service 365 days a year, 24 hours a day, especially during periods of high demand such as cold winter mornings.
- Develop resource plans that result in the lowest reasonable cost to customers in order to provide affordable power for the residents, businesses and communities that depend on DEP.
- Produce robust plans that recognize current trends and future uncertainty in the way power is both produced and consumed given technology advancements in power supply and consumer usage.

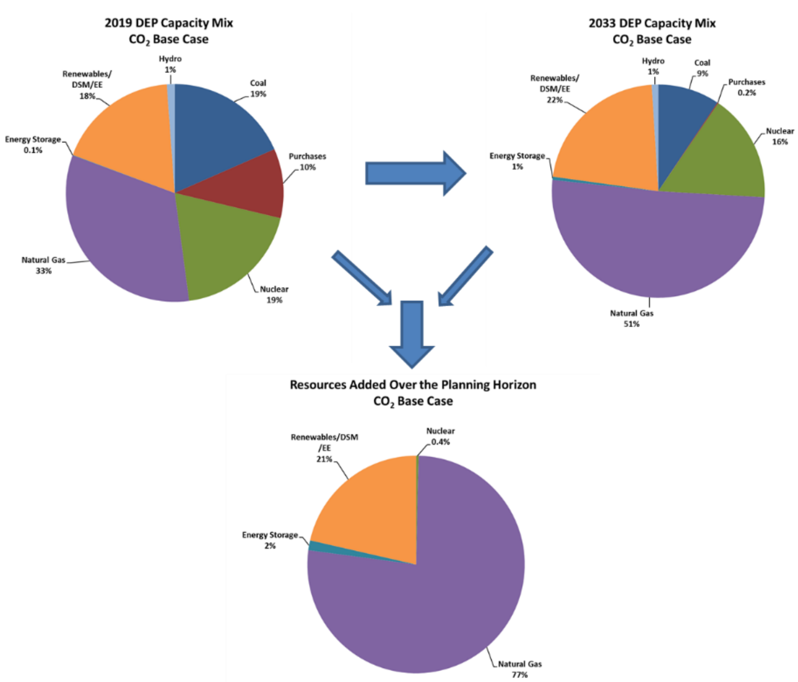
Resource Need:

To maintain long-term reliability, new resource additions are required to meet growing customer demand and to allow for the retirement of aging resources. While extensive Company-sponsored energy efficiency programs help to reduce energy consumption, industry, businesses and residents continue to grow and expand in DEP's service territory. The Company projects the addition of 201,000 new customers contributing to approximately 1,560 MW of additional winter peak demand on the system with annual energy consumption growing by approximately 5,100 GWh between 2019 and 2033. This represents an annual demand growth rate of 0.7% and an energy growth rate of 0.5%. In addition to growing demand, DEP is planning for the potential retirement of some of its older, less efficient generation, creating an additional need of 2,183 MW. The Company also has approximately 1,850 MW of purchased power contracts that expire during the planning period. Finally, beyond just meeting expected consumer demand and replacing retired resources and contract expirations, the plan must also be capable of covering uncertainty caused by variables such as extreme cold weather events or unexpected resource outages. Planning for this uncertainty requires the incorporation of a 17% winter planning reserve margin ensuring that adequate resources are available to reliably serve customers despite these uncertainties. In total, customer growth, retirements, contract expirations and additional reserves will result in the need for approximately 6,300 MW of new resources over the planning horizon.

Planned Additions:

As discussed in more detail in this report, the Company examined several different resource portfolio options to see how each would perform under varying future state assumptions. The development of the base resource plans (one base plan assuming a carbon constrained future and one base plan assuming no future carbon legislation) that best meet the previously stated objectives resulted in the addition of a diverse mix of energy efficiency (EE), Demand-Side Management (DSM), renewable energy resources, and natural gas resources. The plans also contemplate the addition of grid-connected battery storage projects, given their potential to provide solutions for the transmission and distribution systems with the possibility of simultaneously providing benefits to the generation resource portfolio. Technical advancements and declining cost trends in distributed energy resources such as battery storage, distributed solar generation and demand-side management initiatives give rise to a future resource portfolio that is comprised of both centralized resources, as well as a growing penetration of distributed resources. This document discusses the Company's efforts to evolve its planning models to better evaluate these distributed resources as they are integrated into the generation, transmission and distribution systems along with centralized generation such as natural gas and nuclear generation facilities. The figure below shows the Company's 2019 starting resource portfolio capacity mix in the upper left figure, while the upper right figure shows the 2033 projected portfolio at the end of the planning horizon. The figure on the bottom illustrates the incremental resources made over the planning horizon.

Figure Exec-1: 2019 and 2033 Capacity Mix and Sources of Incremental Capacity Additions



As shown in Figure Exec-1, DEP continues to reduce its dependence on coal fired generation with installed coal capacity dropping from 19% of the total portfolio in 2019 to a projection of only 9% by 2033. Renewable resources, energy efficiency and demand-side management also grow from 18% of the capacity mix in 2019 to 22% in 2033, while natural gas resources increase by 18% growing to 51% of the mix by 2033.

As the bottom figure indicates, the plan calls for the significant additions of predominantly dispatchable natural gas generation, as well as renewable generation, battery storage, EE and DSM resources. Together, this combination provides customers with a balanced portfolio with natural gas resources providing dispatchable power at night or when solar output is interrupted due to cloud cover, snow cover or other factors. The additional storage will further help to integrate distributed solar resources into the resource portfolio.

A small amount of nuclear capacity is expected to be added to existing nuclear resources over the 15-year study period due to planned uprates within the existing nuclear fleet. However, nuclear capacity will make up a slightly smaller percentage of total capacity as the total system grows throughout the planning period. No new nuclear generation units are added to the system, nor do the base plans contemplate nuclear retirements over the planning period.

Nuclear Generation:

Low natural gas prices, the absence of national carbon regulation and other industry factors have collectively moved the need for new nuclear generation outside the current planning window. However, shown in the figure above, clean, carbon-free nuclear generation from existing units provides approximately 20% of the installed capacity in DEP's resource portfolio. DEP nuclear resources collectively account for nearly one-half of the total energy produced.

Unlike almost all other resource options, nuclear units provide clean power around the clock every day of the year, except for small periods of outages for refueling and maintenance. As such, nuclear generation is an essential component of the Company's commitment to the provision of affordable, reliable and increasingly clean power.

DEP currently has operating licenses from the Nuclear Regulatory Commission (NRC) that allow the Company to operate its units for sixty years. To ensure these valuable resources are available for the next generation, the Company is working within the framework established by the NRC to evaluate the potential for subsequent license renewals (SLR) of its nuclear units.

SLR would give the Company the option to operate its nuclear facilities an additional twenty years. Chapter 10 describes the Company's ongoing efforts toward the evaluation of SLR.

Renewable Energy and Energy Efficiency:

DEP continues to aggressively pursue additional cost-effective renewable resources as a growing part of its energy portfolio. The Company's commitment, coupled with supporting federal tax credits and state legislation such as South Carolina's Distributed Energy Resource Program Act (SC DER or SC Act 236), North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS), and NC House Bill 589 (HB 589) have led to significant growth in renewable resource development in the Carolinas. The 2018 IRP calls for installed solar capacity to grow from approximately 2,758 MW in 2019 to 4,199 MW in 2033. Chapter 5 of the plan discusses the importance of the Competitive Procurement of Renewable Energy (CPRE) process as a mechanism to acquire new solar resources at the lowest possible cost for customers. Additionally, Chapter 5 discusses future physical and economic factors that will ultimately influence the amount of solar generation that can reliably and affordably be incorporated into DEP's resource portfolio.

In addition to growing renewable generation in the plan, DEP is actively investing in EE and DSM programs that promote, educate and incentivize the efficient utilization of power. DEP offers a wide range of EE programs to its residential, commercial and industrial customers to help them reduce their power consumption. These efforts are expected to help decrease the projected growth in annual energy consumption by approximately 22% over the planning horizon.

Dispatchable Natural Gas:

An important component of DEP's resource portfolio is the addition of dispatchable natural gas resources that are required for long-term system reliability, as well as for the provision of day-to-day, hour-to-hour and even minute-to-minute load following capabilities. Improvements in natural gas turbine technology provide additional flexibility to the resource portfolio relative to older assets that are being retired, while efficiency improvements reduce the amount of fuel required to produce the same amount of electricity. These technology developments make these natural gas technologies attractive, resulting in a resource portfolio with a smaller environmental footprint, while also providing additional real-time ramping capabilities to better follow changes in system load requirements and varying levels of solar output. At times, these resources may be needed for short durations to provide power during high load periods caused by extreme temperatures. In other instances, these dispatchable resources are needed to run for days, or even weeks at a time, to provide power when other units are offline for maintenance or during periods of extended cloud cover that reduce the output of solar generation. DEP's resource plans call for the addition of approximately 2,760 MW of simple cycle combustion turbine (CT) technology and 3,236 MW of combined cycle (CC) generation technology to help meet load growth, replace unit retirements and expiring purchase power contracts, and optimally meet the needs of the system.

Conclusion:

In summary, the 2018 IRP Base Cases, discussed later in this document, show planned resource additions necessitated by load growth, retirement of aging generation resources and expiration of purchased power contracts. The plans are consistent with DEP's commitment to a smarter energy future, providing customers with reliable, affordable and increasingly clean sources of energy. Additionally, they maintain the Company's sustainability goals to reduce DEP's carbon emissions by more than 40% from 2005 levels by 2030. The plans accomplish this goal, despite serving significantly more customer demand over the planning period and without federal or state carbon mandates. Achieving robust base plans that balance the previously stated objectives requires a diverse mix of additional EE, DSM, renewable resources, energy storage and new efficient dispatchable natural gas resources. Plans that concentrate too much on a single resource result in additional customer costs, higher carbon emissions or both.

The following chapters of this document provide an overview of the assumptions, inputs, analysis and results included in the 2018 IRP. In addition to two Base Case plans, five different resource portfolios were analyzed under multiple sensitivities. The appendices to the document give even greater detail and specific information regarding the input development and the analytic process utilized in the 2018 IRP. A more detailed presentation of the Base Cases described above is included in this document in Chapter 12 and Appendix A.

Finally, DEP will continue to closely monitor changes in key variables such as technology cost trends, the system load forecast, fuel price forecasts, emerging technology performance characteristics, the pace of adoption of distributed resources, advancements in storage technologies, new federal or state energy policies and other key variables. To the extent these variables change over time, DEP will incorporate such changes in subsequent annual IRP reports.

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 1.56 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. All capacities represent winter ratings, unless otherwise noted:

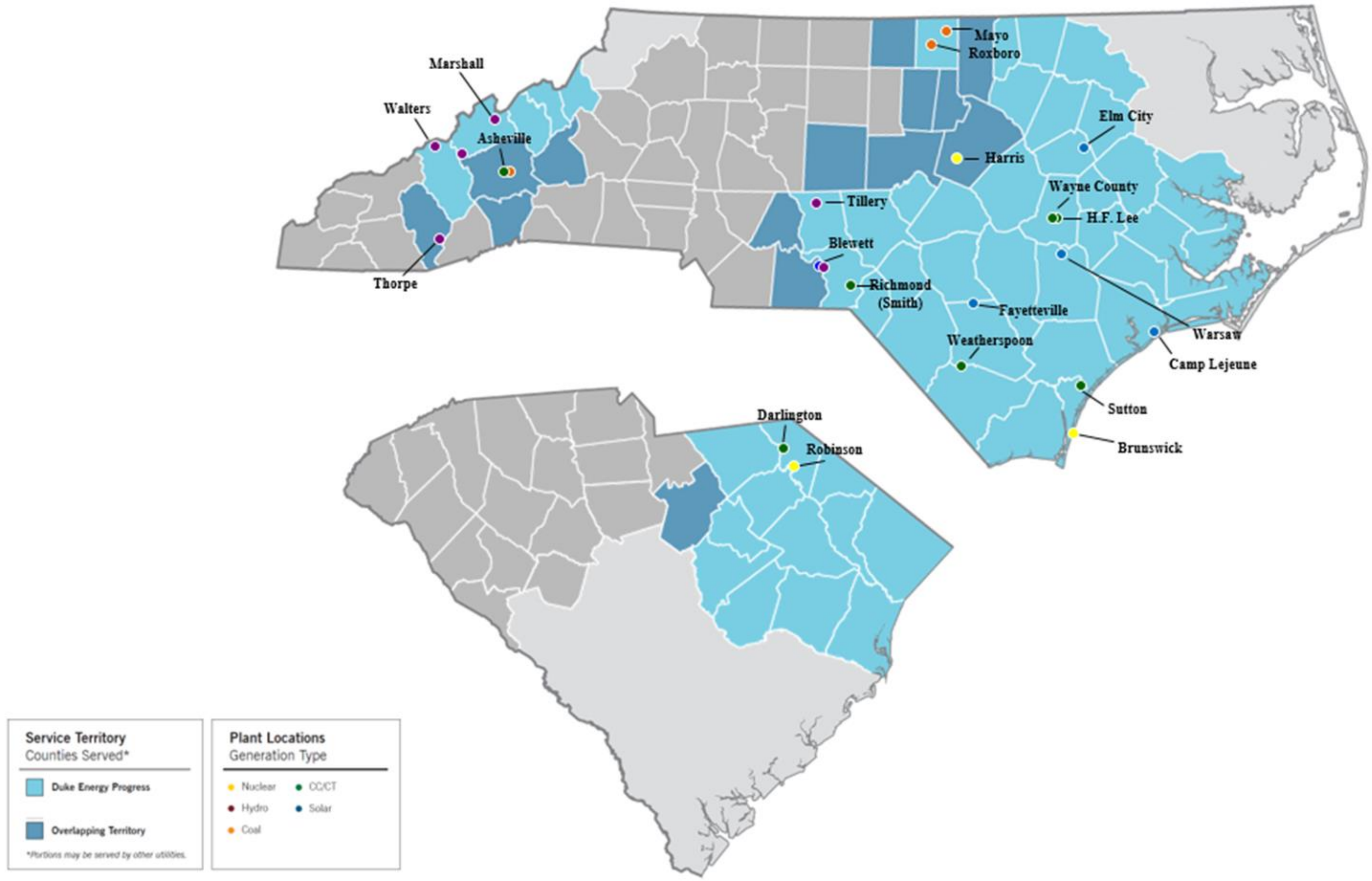
- Three nuclear generating stations with a combined net capacity of 3,705 MW
- Three coal-fired stations with a combined capacity of 3,592 MW
- Four hydroelectric stations with a combined capacity of 227 MW
- Ten combustion turbine stations including four combined cycle units with a combined capacity of 6,388 MW
- Four utility-owned solar facilities with a combined capacity of 141 MW (nameplate)[1]

DEP's power delivery system consists of approximately 75,836 miles of distribution lines and 6,241 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: Duke Energy Carolinas (DEC), PJM, Tennessee Valley Authority (TVA), Cube Hydro, 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 (formerly Southeastern Electric Reliability Council), and North American Electric Reliability Corporation (NERC).

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

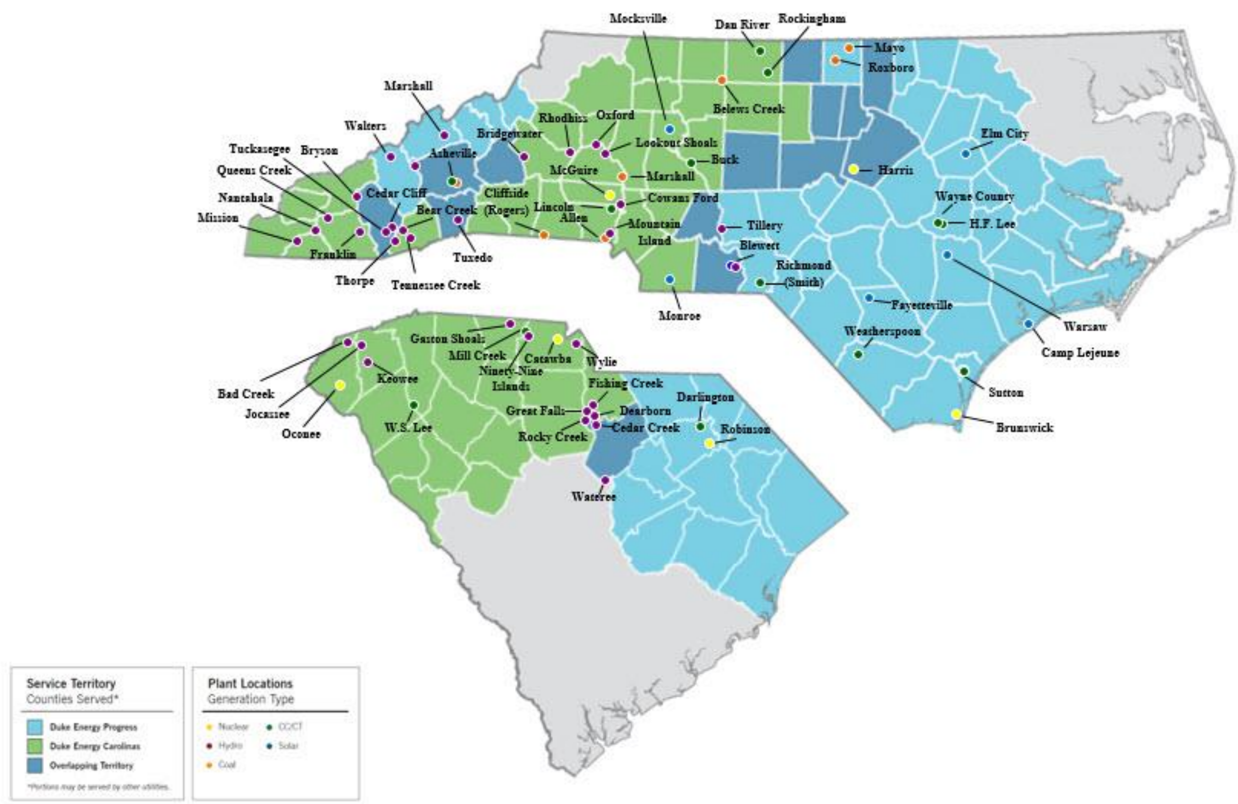
[1] The capacity represented in this listing only includes utility-owned solar capacity. Capacity from purchased power contracts are not included.

Figure 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 South Carolina and North Carolina customers of both utilities. An illustration of the service territories of the Companies is shown in the map below.

Figure 2-B: DEP and DEC Service Area



3. ELECTRIC LOAD FORECAST

The Duke Energy Progress Spring 2018 load forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2019 – 2033 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 2018 Forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of South Carolina and North Carolina.

Moody's Analytics supplies the Company with economic and demographic projections, which are used in the energy and demand models. Preliminary analysis of Moody's historical projections versus actuals resulted in smaller variances and minimum bias during normal economic periods. However, the likelihood of greater forecast variance and forecast bias increases during unique disruptive economic periods like the Great Recession. Load Forecasting will continue to monitor Moody's forecast error going forward.

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

The Residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electricity prices 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 increases in the number of customers being added to the system. The average annual energy growth rate of Residential in the Spring 2018 forecast, including the impacts of Utility EE (UEE) programs, Solar and Electric Vehicles from 2019 to 2033 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 energy sales are expected to grow 0.6% per year over the forecast horizon.

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 0.2% per year over the forecast horizon, after all adjustments.

Peak Demand and Energy Forecast:

The load forecast projection for energy and capacity, including the impacts of UEE, rooftop solar, and electric vehicles, that was utilized in the 2018 IRP is shown in Table 3-A.

Table 3-A: Load Forecast with Energy Efficiency Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2019	13,317	14,011	64,038
2020	13,322	14,016	63,669
2021	13,324	14,001	63,613
2022	13,416	14,089	63,393
2023	13,510	14,139	63,809
2024	13,658	14,308	64,622
2025	13,796	14,415	65,178
2026	14,014	14,568	65,145
2027	14,118	14,713	65,726
2028	14,336	14,903	66,593
2029	14,473	15,032	67,080
2030	14,605	15,155	67,548
2031	14,762	15,303	68,108
2032	14,941	15,475	68,787
2033	15,054	15,575	69,125
Avg. Annual Growth Rate	0.8%	0.7%	0.5%

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 (EE) and demand-side management (DSM).

Since 2009, DEP has been actively developing and implementing new EE and DSM programs throughout its South Carolina and North 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 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 Public Service Commission of South Carolina (PSCSC) and the North Carolina Utilities Commission (NCUC) 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.

In 2016, DEP commissioned an EE market potential study to obtain estimates of the technical, economic and achievable potential for EE savings within the DEP service area. The final report was prepared by Nexant, Inc. and was completed in December 2016. The results of the market potential study are suitable for integrated resource planning purposes and use in long-range system planning models. However, the study did not attempt to closely forecast short-term EE achievements from year to year. Therefore, the Base Case EE/DSM savings contained in this IRP were projected by blending DEP's five-year program planning forecast into the long-term achievable potential projections from the market potential study.

DEP prepared a Base Portfolio savings projection that was based on DEP's five-year program plan for 2018-22. For the period of 2023 through 2027, the Company employed an interpolation methodology to blend together the projection from DEP's program plan and the Market Potential Study Achievable Potential. For periods beyond 2027, the Base Portfolio assumed that the Company could achieve the annual savings projected in the Achievable Portfolio presented in Nexant's Market Potential Study.

DEP also prepared a High EE Portfolio savings projection based on the Enhanced Scenario contained in Nexant's Market Potential Study, which assumed the implementation of potential new technologies and programs not currently offered by DEP can encourage additional customer participation and savings.

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.

5. RENEWABLE ENERGY STRATEGY / FORECAST

The growth of renewable generation in the United States continues to outpace that of non-renewable generation. According to EIA, in 2017, including small-scale solar, 14.5 GW of wind and solar capacity were installed nationwide compared to 9.3 GW of natural gas. About 4 GW of natural gas was retired in 2017 and over 6 GW of coal was retired with no new coal-fired generation installed.[2]

North Carolina ranked second in the country in solar capacity added in 2017, and remains second behind only California in total solar capacity online. According to GTM Research, South Carolina also cracked the top 10 in 2018, adding nearly 400 MW in 2017. Duke Energy's compliance with the South Carolina Distributed Energy Resource Program (SC DER), the North Carolina Renewable Energy and Energy Efficiency Portfolio Standards (NC REPS), and the Public Utility Regulatory Policies Act (PURPA), as well as the availability of the Federal Investment Tax Credit (ITC) were key factors behind the high penetration of solar.

The interconnection queue has continued to grow, with the DEP and DEC combined solar queue representing approximately 12 GW. Key drivers to queue growth have been the implementation of South Carolina Act 236 (SC Act 236), upcoming procurement for HB 589 (described below), and North Carolina's historically favorable avoided cost rate and 15-year contract terms for qualifying facilities (QFs) under PURPA.

The implementation of North Carolina House Bill 589 (HB 589), which calls for the addition of 2,660 MW of competitively procured renewable resources over a 45-month period, is significant to the amount of solar projected to be operational during the planning horizon. Growing customer demand, the federal ITC, and declining installed solar costs make solar capacity the Company's primary renewable energy resource in the 2018 IRP. The following key assumptions regarding renewable energy were included in the 2018 IRP:

- Installed solar capacity increases in DEP from 2,758 MW in 2019 to 4,199 MW in 2033;
- Achievement of the SC Act 236 goal of 39 MW of solar capacity located in DEP;
- Compliance with NC REPS continues to be met through a combination of solar, other renewables, EE, and Renewable Energy Certificate (REC) purchases; and
- Implementation of HB 589 and continuing solar cost declines drive solar capacity growth above and beyond SC Act 236 requirements and NC REPS requirements.

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[2] All renewable energy GW/MW represent GW/MW-AC (alternating current) unless otherwise noted.

HB 589 Competitive Procurement of Renewable Energy (CPRE):

HB 589 establishes a competitive solicitation process, known as the Competitive Procurement of Renewable Energy (CPRE), which calls for the addition of 2,660 MW of competitively procured renewable resources across the Duke Energy Balancing Authority Areas over a 45-month period. On July 10, 2018, Duke issued a request for bids for the first tranche of CPRE, requesting 600 MW in DEC and 80 MW in DEP. South Carolina and North Carolina projects may submit proposals into CPRE.

The Companies expect to issue three "tranches" of requests for bids. Future tranches of CPRE may be affected by capacity referred to in this document as the "Transition MW." "Transition MW" represents the total capacity of renewable generation projects in the combined Duke Balancing Authority area that are (1) already connected; or (2) have entered into purchase power agreements (PPAs) and interconnection agreements (IAs) as of the end of the 45-month competitive procurement period, provided that they are not subject to curtailment or economic dispatch. The total CPRE target of 2,660 MW will vary based on the amount of Transition MW at the end of the 45-month period, which HB 589 expected to total 3,500 MW. If the aggregate capacity in the Transition MW exceeds 3,500 MW, the competitive procurement volume of 2,660 MW will be reduced by the excess amount; conversely, if the Transition falls short of 3,500 MW the Companies will conduct additional competitive procurement. The Company believes the Transition MW will easily total 3,500 MW and possibly exceed it by as much as 1,200 MW.

In preparation for the HB 589 competitive procurement process, the Company 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. In anticipation of future solar growth, DEP is positioning itself to properly integrate renewable resources to the grid regardless of ownership.

In addition to ensuring DEP has operational control over future solar associated with HB 589, 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.

Interconnection Queue:

Through the end of 2017, DEP had more than 2,000 MW of utility scale solar on its system, with over 600 MW interconnecting in 2017. When renewable resources were evaluated for the 2018 IRP, DEP reported another approximately 1,000 MW of third party solar under construction and more than 6,000 MW in the interconnection queue. Table I-1 contains interconnection queue information which provides details on the number of pending projects and pending capacity by state.

Projecting future solar connections from the interconnection queue presents a significant challenge due to the large number of project cancellations, ownership transfers, interconnection studies required, and the unknown outcome of which projects will be selected through the CPRE program.

NC REPS Compliance:

DEP remains 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 renewable and energy efficiency resources. DEP's long-term general compliance needs are expected to be met through a combination of renewable resources, including RECs obtained through the HB 589 competitive procurement process.

HB-589 Competitive Procurement and Utility-Owned Solar:

DEP continues to evaluate utility-owned solar additions to grow its renewables portfolio. DEP owns and operates four 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, NC placed in service in November 2015;
- Warsaw Solar Facility – 65MW, located in Duplin County, NC placed in service in December 2015;
- Fayetteville Solar Facility – 23MW, located in Bladen County, NC placed in service in December 2015; and
- Elm City Solar Facility – 40MW, located in Wilson County, NC placed in service in March 2016.

No more than 30% of the CPRE Program requirement may be satisfied through projects in which Duke Energy or its affiliates have an ownership interest at the time of bidding. DEP intends to bid into the first and future tranches of the CPRE and will also evaluate the potential for acquiring facilities where appropriate. HB 589 does not stipulate a limit for DEP's option to acquire projects from third parties that are specifically proposed in the CPRE RFP as acquisition projects, though any such project will not be procured unless determined to be among the most cost-effective projects submitted.

Additional Factors Impacting Future Solar Growth:

A number of factors impact the Company's forecasting of future solar growth. First, potential changes in the Company's avoided cost may impact the development of projects under PURPA and HB 589. Avoided cost forecasts are subject to variability due to changes in factors such as natural gas and coal commodity prices, system energy and demand requirements, the level and cost of generation ancillary service requirements and interconnection costs. PURPA requires utilities to purchase power from QFs at or below the utility's avoided cost rate. HB 589 requires that competitive bids are priced below the Utility's avoided cost rates, as approved by the NCUC, in order to be selected. Therefore, the cost of solar is a critical input for forecasting how much solar will materialize in the future.

Solar costs are also influenced by other variables. Panel prices have decreased at a significant rate and are expected to continue to decline. However, in January 2018, President Trump announced a tariff on solar modules and cells with a rate of 30% in year 1, declining 5% until the fourth and final year in which the tariff rate is 15%. Additional factors that could put upward pressure on solar costs include direct interconnection costs, as well as costs incurred to maintain the appropriate operational control of the facilities. Finally, as panel prices have decreased, there has been more interest in installing single-axis tracking (SAT) systems and/or systems with higher inverter load ratios (ILR) which change the hourly profile of solar output and increase expected capacity factors. DEP now models fixed tilt and SAT system hourly profiles with a range of ILR's as high as 1.6 (DC/AC ratio).

In summary, there is a great deal of uncertainty in both the future avoided cost applicable to solar and the expected price of solar installations in the years to come. As a result, the Company will continue to closely monitor and report on these changing factors in future IRP and competitive procurement filings.

HB 589 Customer Programs:

In addition to the CPRE program, HB 589 offers direct renewable energy procurement for major military installations, public universities, and other large customers, as well as a community solar program. These programs will complement the existing SC Act 236 Programs.

As part of HB 589, the renewable energy procurement program for large customers such as military installations and universities enables large customers to procure renewable energy attributes from new renewable energy resources. The program allows for up to 600 MW of total capacity, with set asides for military installations (100 MW of the 600 MW) and the University of North Carolina system (250 MW of the 600 MW). The 2018 IRP base case assumes all 600 MW of this program materialize, with the DEP/DEC split expected to be roughly equal. If all 600 MW are not utilized, the remainder will roll back to the competitive procurement, increasing its volume.

The community solar portion of HB 589 calls for up to 20 MW of shared solar in DEP. This program is similar to the SC Act 236 shared solar program, and allows customers who cannot or do not want to put solar on their property to take advantage of the economic and environmental benefits of solar by subscribing to the output of a centralized facility. The 2018 IRP Base Cases assume that all 20 MW of the HB 589 shared solar program materializes.

HB 589 also calls for a rebate program for rooftop solar. The rebate program opened in July and the program has already proven to spur greater interest in solar installations and therefore, more net metered customers in NC. Through May 2018, DEP has installed nearly the same capacity of rooftop solar as was installed in all of 2017. Enough customers were processed in the first two weeks of the rebate program to fill the 2018 allotment for Residential and Commercial customers.

SC Act 236:

Steady progress continues to be made with the first two tiers of the SC DER Program summarized below, completion of which would unlock the third tier:

- Tier I: 13 MW of solar capacity from facilities each >1 MW and < 10 MW in size.
- Tier II: 13 MW of behind-the-meter solar facilities for residential, commercial and industrial customers, each ≤1 MW, 25% of which must be ≤ 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 <10 MW in size. Upon completion of Tiers I and II (to occur no later than 2021), the Company may directly invest in additional solar generation to complete Tier III.

DEP has executed two PPAs to complete Tier I which will result in 15 MW, 5 MW of which are currently operational. Tier II incentives have resulted in growth in private solar in DEP, resulting in approximately 12 MW that are currently installed.

The Company launched its first Shared Solar program as part of Tier I. Duke Energy designed its initial SC Shared Solar program to have appeal to residential and commercial customers who rent or lease their premises, residential customers who reside in multifamily housing units or shaded housing or for whom the relatively high up-front costs of solar PV make net metering unattainable, and non-profits who cannot monetize the ITC.

Wind:

DEP considers wind a potential energy resource in the long term to support increased renewables portfolio diversity and long-term general compliance need. However, investing in wind inside of DEP's footprint may be challenging in the short term, primarily due to a lack of suitable sites, permitting challenges, and more modest capital cost declines relative to other renewable technologies like solar. Opportunities may exist to transmit wind energy into the Carolinas from out of state regions where wind is more cost-effective.

Summary of Expected Renewable Resource Capacity Additions:

The 2018 IRP incorporates the Base Case renewable capacity forecast below. This case includes renewable capacity components of the Transition MW of HB 589, such as capacity required for compliance with the SC DER Program, NC REPS, PURPA purchases and the additional three components of HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). This year's Base Case also includes additional projected solar growth beyond HB 589. While certain regions of DEP may become saturated with solar, it is the Company's belief that continued declines in the installation cost of solar and storage will enable solar and coupled "solar plus storage" systems to contribute to growing energy needs. The Company also believes supportive policies for solar and solar plus storage will continue to exist in SC and NC even beyond the HB 589 procurement horizon.

The Company anticipates a diverse portfolio including solar, biomass, hydro, wind, and other resources. Actual results could vary substantially for the reasons discussed previously, as well as other potential changes to legislative requirements, tax policies, technology costs, 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 is not at 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 that it may push the time of summer peak to a later hour if solar penetration levels continue to increase. However, solar is unlikely to have a similar impact on the morning winter peak due to little solar output in the morning hours. Solar capacity contribution to summer and winter peak demands is discussed more fully in Chapter 9.

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
2019	2758	266	3024	965	266	1231	2019	28	266	293
2020	3061	266	3327	1071	266	1337	2020	31	266	296
2021	3341	120	3461	1157	120	1278	2021	33	120	154
2022	3588	115	3703	1231	115	1346	2022	36	115	151
2023	3760	103	3862	1271	103	1374	2023	38	103	140
2024	3938	102	4041	1289	102	1391	2024	39	102	142
2025	4019	73	4092	1297	73	1370	2025	40	73	113
2026	4053	73	4125	1300	73	1373	2026	41	73	113
2027	4086	67	4153	1304	67	1371	2027	41	67	108
2028	4120	14	4134	1307	14	1321	2028	41	14	55
2029	4153	3	4156	1310	3	1313	2029	42	3	44
2030	4187	2	4188	1314	2	1315	2030	42	2	43
2031	4191	2	4192	1314	2	1316	2031	42	2	44
2032	4195	0	4195	1314	0	1314	2032	42	0	42
2033	4199	0	4199	1315	0	1315	2033	42	0	42

* Solar includes 0.5% per year degradation
** Capacity listed excludes REC-Only contracts

Given the significant volume and uncertainty around solar penetration, high and low solar portfolios were compared to the Base Case described above. The portfolios do not 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 renewable 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, and/or high ancillary costs which may drive down the economic viability of future incremental solar additions. These events may cause solar projections to fall short of the Base Case if the CPRE, renewable energy procurement for large customers, and/or the community solar programs of HB 589 do not materialize or are delayed. 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
2019	2774	266	3040	971	266	1237	2019	28	266	294
2020	3114	266	3380	1089	266	1355	2020	31	266	297
2021	3489	120	3610	1202	120	1322	2021	35	120	155
2022	3728	115	3843	1268	115	1383	2022	37	115	152
2023	3900	103	4003	1285	103	1388	2023	39	103	142
2024	4076	102	4178	1303	102	1405	2024	41	102	143
2025	4205	73	4278	1316	73	1389	2025	42	73	115
2026	4259	73	4332	1321	73	1394	2026	43	73	115
2027	4313	67	4380	1326	67	1393	2027	43	67	110
2028	4366	14	4380	1332	14	1345	2028	44	14	57
2029	4419	3	4422	1337	3	1340	2029	44	3	47
2030	4472	2	4474	1342	2	1344	2030	45	2	46
2031	4485	2	4487	1344	2	1345	2031	45	2	46
2032	4498	0	4498	1345	0	1345	2032	45	0	45
2033	4510	0	4510	1346	0	1346	2033	45	0	45

* Solar includes 0.5% per year degradation
** Capacity listed excludes REC-Only contracts

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
2019	2647	266	2913	926	266	1192	2019	26	266	292
2020	2976	266	3242	1042	266	1307	2020	30	266	296
2021	3255	120	3375	1131	120	1252	2021	33	120	153
2022	3397	115	3512	1174	115	1289	2022	34	115	149
2023	3463	103	3566	1194	103	1297	2023	35	103	137
2024	3516	102	3618	1210	102	1312	2024	35	102	138
2025	3536	73	3609	1216	73	1289	2025	35	73	109
2026	3572	73	3645	1227	73	1299	2026	36	73	108
2027	3608	67	3675	1238	67	1304	2027	36	67	103
2028	3644	14	3658	1248	14	1262	2028	36	14	50
2029	3680	3	3683	1259	3	1262	2029	37	3	39
2030	3716	2	3717	1267	2	1268	2030	37	2	39
2031	3712	2	3714	1266	2	1268	2031	37	2	39
2032	3709	0	3709	1266	0	1266	2032	37	0	37
2033	3705	0	3705	1266	0	1266	2033	37	0	37

* Solar includes 0.5% per year degradation

** Capacity listed excludes REC-Only contracts

6. INTEGRATED SYSTEMS AND OPERATIONS PLANNING (ISOP) AND BATTERY STORAGE

The Industry is Rapidly Changing:

In recent years, the electric utility industry has undergone extraordinary transformation that has directly resulted in an increasingly dynamic environment for which the Company must plan and operate. This transformation is driven by several key trends including rapidly changing technologies, evolving customer expectations and the progression towards a smarter grid. New technologies are being developed at an exponential rate, creating a multitude of new possibilities of assets to serve customers. Many Duke Energy customers have come to realize the benefits that technology can provide and are no longer inactive recipients of a simple commodity at the least possible cost. These customers are now expecting more choices and services to control their energy use and desire active interaction with their energy choices. Duke Energy Progress is committed to serving its customers in new and improved ways that recognize the increasing differences between its customers. To do so will make planning more complex. For example, the Company will need much better data on how its customers want to be served, and that data will not be easy to obtain. Providing safe, reliable, cleaner and affordable power, however, will always be at the heart of Duke Energy's foundation. Furthermore, the commitment to provide transparency to both customers and other stakeholders is of utmost importance, due to the belief that taking advantage of the collective knowledge of the parties will ultimately benefit all customers.

Implications for the IRP:

The Company, as well as others in the electric utility industry, are recognizing that the traditional methods of utility resource planning must be enhanced to keep pace with changes occurring in the industry. As a result, beginning this year, Duke Energy Progress will begin to adapt its IRP to adjust to this changed world, recognizing that this process will continue to evolve. The planning tools that have been used in the past are limited in their ability to value some aspects of the newer technologies. Historically, the Company has not been able to identify the locational value of distributed generation sources and are now developing models to do so, as well as more tightly link our distribution plans to the bulk power (generation and transmission) plans. DEP also recognizes the sub-hourly operational impacts of intermittency of some supply resources and is developing modeling capabilities needed to quantify these operational impacts. As the single entity responsible for the reliable operations of the system, DEP is required to address what it will take to operate its system under a wider variety of futures, which will directly result in the consideration of more scenarios. Also, with the accelerated pace of change, the Company must place a higher value on the flexibility of the resource plan to adapt to changing circumstances.

Changes reflected in this year's IRP:

Based on recent developments, the amount of renewables on the DEP system has increased to reflect HB 589 requirements and the expected renewable adoption is now forecasted to exceed the legislatively mandated limits. As a result, the need for real-time system regulation and balancing increases over time as more intermittent renewables are integrated into the system. While the models are not yet perfected, DEP can now make reasonable estimates for these real-time system impacts and those estimates have been included in the long-term planning models for the first time. DEP has also assumed the deployment of more grid-connected battery storage within the next few years which, if deployed appropriately, have the potential to provide benefits to the transmission and distribution system, as well as the bulk power system.

Changes to be Included in Future IRPs:

Duke Energy is further addressing these shifting trends through the Integrated System and Operations Planning (ISOP) effort. ISOP envisions the creation of a broader process by which all energy resources are evaluated fully and fairly valued on functional capability, irrespective of the resource location on the grid. ISOP strives to identify the appropriate tools and examine the performance of different asset portfolios across a variety of potential futures. ISOP has completed evaluations of the current planning practices and has identified future enhancements to be addressed in a systematic, disciplined manner to realize this future vision.

One key goal of ISOP is for the planning models to reasonably mimic the future operational realities to allow DEP to serve its customers with newer technologies. The introduction of balancing and regulating reserve requirements with respect to growing renewable generation in this IRP is an indication of this effort. Additionally, ISOP has a number of other workstreams addressing the identified future enhancements to the modeling tools, the need for granularity in location and time, as well as the approach for stacking functional benefits across the system. These future enhancements in planning are expected to be addressed over the next several years, as soon as the modeling tools, processes and data development will allow.

Duke Energy recognizes the substantial effort it will take to continue down this integrated planning path for years to come, and is committed to the development and delivery of these new methods. There are considerable risks and learning curves with a number of these new workstreams as many of the modeling tools and functionalities are currently in developmental stages throughout the industry. Given that some of the most promising emerging resource solutions, such as battery storage and leading-edge intelligent grid controls, are still in the early stages, Duke Energy is committed to understanding and capturing these capabilities. There will also be a heightened need to address data challenges such as the increased levels of granularity associated with automated systems and data storage requirements. Duke Energy is committed to addressing these and other potential risks. The Company recognizes that it is proceeding with the first few steps of an evolutionary journey. DEP looks forward to public feedback as the IRP process evolves, and is committed to openly considering all viewpoints and new data that will improve the ability to plan for and meet the needs of its customers

Battery Storage:

As introduced in the ISOP discussion, the Company is assessing the integration of battery storage technology into its portfolio of assets. Battery storage costs are expected to continue to decline, which may make this resource a viable option for grid support services, including frequency regulation, solar smoothing during periods with high incidences of intermittency, as well as the potential to provide overall energy and capacity value. Energy Storage can also provide value to the transmission and distribution (T&D) system by deferring or eliminating traditional upgrades and can be used to improve reliability and power quality to locations on the Company's distribution system. This approach results in stacked benefits which couples value streams from the Transmission, Distribution, and Generation systems. This unique evaluation process falls outside of the Company's traditional IRP process, which focuses primarily on meeting future generation needs reliably and at the lowest possible cost. This new approach to evaluating technologies that have generation, transmission and distribution value is being addressed through the ISOP enhancements, discussed above.

The Company will begin investing in multiple grid-connected storage systems dispersed throughout its South and North Carolina service territories that will be located on property owned by the Company or leased from its customers. These deployments will allow for a more complete evaluation of potential benefits to the distribution, transmission and generation system while also providing actual operations and maintenance cost impacts of batteries deployed at a significant scale. This will allow the Company to explore the nature of new offerings desired by customers and fill knowledge gaps, such as how the Company can best integrate battery storage into its daily operations. The Company will work with Generation, Transmission and Distribution departments in this evaluation process, utilizing the ISOP framework. The goal is to optimize the location to couple localized T&D system benefits with bulk system benefits, and to minimize cost and maximize benefits for its customers. The Company believes such investments are consistent with the direction of state policy in both SC and NC under the SC DER Program and NC HB 589, respectively. Additionally, the Company continues to participate in an energy storage study to assess the economic potential for NC customers, mandated by HB 589. Results of the study are expected in December 2018.

7. 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 SC Act 236, NC REPS, and HB 589. The remainder of the future generation needs can be met with a variety of potential supply side technologies.

For purposes of the 2018 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 duct firing, Combined Heat and Power (CHP), reciprocating engines, and nuclear units. In addition, Duke Energy Progress considered renewable technologies such as Wind, Solar PV, Landfill Gas and storage options such as Pumped Storage Hydro (PSH) and Lithium Ion Batteries in the screening analysis. Hybrids of the above technologies were also considered (i.e. solar steam augmentation and solar PV plus battery).

For the 2018 IRP screening analysis, the Company screened technology types within their own respective general categories of baseload, peaking/intermediate, renewable, and storage, with the goal of screening to pass the best alternatives from each of these four 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 on the DEP system. 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 (Winter 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 – 667 MW – 1x1x1 Advanced Combined Cycle (No Inlet Chiller and Fired)
- Base load – 1,339 MW – 2x2x1 Advanced Combined Cycle (No Inlet Chiller and Fired)
- Base load – 22 MW – Combined Heat & Power (Combustion Turbine)
- Base load – 9 MW – Combined Heat & Power (Reciprocating Engine)
- Base load – 600 MW – Small Modular Reactor (SMR)
- Peaking/Intermediate – 196 MW 4 x LM6000 Combustion Turbines (CTs)
- Peaking/Intermediate – 202 MW, 12 x Reciprocating Engine Plant
- Peaking/Intermediate – 574 MW 2 x G/H-Class Combustion Turbines (CTs)
- Peaking/Intermediate – 754 MW 2 x J-Class Combustion Turbines (CTs)
- Peaking/Intermediate – 919 MW 4 x 7FA.05 Combustion Turbines (CTs)
- Storage – 5 MW / 5 MWh Li-ion Battery
- Storage – 20 MW / 80 MWh Li-ion Battery
- Storage – 1,400 MW Pumped Storage Hydro (PSH)
- Renewable – 75 MW Wood Bubbling Fluidized Bed (BFB, biomass)
- Renewable – 5 MW Landfill Gas

Non-Dispatchable (Nameplate)

- Renewable – 150 MW Wind - On-Shore
- Renewable – 50 MW Solar PV, Fixed-tilt (FT)
- Renewable – 50 MW Solar PV, Single Axis Tracking (SAT)

8. 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.

2016 Resource Adequacy Study:

The Company retained Astrapé Consulting in 2016 to conduct an updated resource adequacy study.[3] The updated study was warranted to account for the extreme weather experienced in the service territory in recent winter periods, and the significant amount of solar capacity that has been added to the system and in the interconnection queue. Solar resources provide meaningful capacity benefits in the summer since peak demand typically occurs in afternoon hours when the sun is shining and solar resources are available. However, solar resources contribute very little capacity value to help meet winter peak demands that typically occur in early morning hours.

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[3] Astrapé Consulting is an energy consulting firm with expertise in resource adequacy and integrated resource planning. Astrapé also conducted resource adequacy studies for DEC and DEP in 2012.

Methodology:

The 2016 resource adequacy study incorporated the uncertainty of weather, economic load growth, unit availability, and the availability of transmission and generation capacity for emergency assistance. Astrapé 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.

Winter Capacity Planning:

In the past, loss of load risk was typically concentrated during the summer months and a summer reserve margin target provided adequate reserves in both the summer and winter periods. However, the incorporation of recent winter load data and the significant amount of solar penetration included in the 2016 study, shows that the majority of loss of load risk is now heavily concentrated during the winter period. The shift in seasonal LOLE is the result of greater winter load volatility, as well as the high penetration of solar resources and the associated capacity contribution to summer reserves compared to winter reserves. The seasonal shift of LOLE to the winter period also increases as greater amounts of solar capacity are added to the system. Thus, increasing solar penetrations shift the planning process to a winter focus. Winter load and resources now drive the timing need for new capacity additions and a winter planning reserve margin target is now needed to ensure that adequate resources are available throughout the year to meet customer demand.

Results:

Based on results of the 2016 resource adequacy assessment, the Company adopted a 17% minimum winter reserve margin target for scheduling new resource additions and incorporated this planning criterion beginning with the 2016 IRP.

Adequacy of Projected Reserves:

DEP's resource plan reflects winter reserve margins ranging from approximately 17% to 25%. Reserves projected in DEP's IRP meet the minimum planning reserve margin target and thus satisfy the one day in 10 years LOLE criterion. Projected reserve margins often exceed the minimum 17% winter target by 3% or more in years immediately following new resource additions. Reserve margins are projected to exceed the minimum 17% winter target by 3% or more in 2025 and 2027 due to the combined cycle capacity additions in those years. The projected reserve margin also exceeds the minimum target by about 3% in 2029 due to the addition of a block of CT capacity.

The IRP provides general guidance in the type and timing of resource additions. As previously noted, projected reserve margins will often be somewhat higher than the minimum target in years immediately following new generation additions since capacity is generally added in large blocks to take advantage of economies of scale. 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 the Company's IRP are appropriate for providing an economic and reliable power supply.

9. CAPACITY VALUE OF SOLAR

Solar Capacity Value Study Summary:

As DEP and DEC continue to add solar to their systems, understanding the reliability contribution of solar resources is critical for generation planning and projecting capacity needs as part of the Integrated Resource Plan. Conventional thermal resources are typically counted as 100% of net capability in reserve margin calculations for future generation planning since these resources are fully dispatchable resources when not on forced outage or planned maintenance. Due to the diurnal pattern and intermittent nature of solar resources, it is not reasonable to assume that these resources provide the same capacity value as a fully dispatchable resource. Peak loads for DEP and DEC in the winter occur in the early morning and late evening when the solar output is low, while peak loads in the summer occur across the afternoon and early evening which is more coincident with solar output. Solar output shapes and the timing of peak demand periods must be considered to determine the capacity value or reliability contribution of a solar resource compared to a fully dispatchable resource such as a combustion turbine.

Astrapé performed this solar capacity value study for the Companies using the Strategic Energy Risk Valuation Model (SERVM) which was the same model utilized for the 2016 Resource Adequacy Studies. Extensive work went into the development of fixed-tilt and single-axis-tracking solar profiles across a 13-location grid in South Carolina and North Carolina.

Astrapé calculated the incremental capacity value of solar across five solar penetration levels for each company. The table below shows the different penetration levels of renewable solar generation for both DEP and DEC. These levels are consistent with the Companies' estimates of penetration at the time of this analysis. Consistent with NC House Bill 589, solar additions were divided up into the categories of Existing Plus Transition and then an additional four tranches of solar that are expected over the next few years. However, note that the tranches discussed in this study reflect the Companies' total expected solar procurement which includes all utility scale requirements under NC HB 589 (CPRE, large customer programs and community solar). While the exact timing and amounts of transition and incremental solar additions may change over time, it is reasonable to assume the levels provided in the table below given the current procurement targets of the Companies.

Table 9-A: Simulated Solar Penetration Levels

	DEC Incremental MW	DEC Cumulative MW	DEP Incremental MW	DEP Cumulative MW
0 MW Level	–	–	–	–
Existing Plus Transition MW	840	840	2,950	2,950
Tranche 1	680	1,520	160	3,110
Tranche 2	780	2,300	180	3,290
Tranche 3	780	3,080	160	3,450
Tranche 4	420	3,500	135	3,585

Table 9-B below shows the seasonal LOLE weightings for the different increments of solar for DEP. As solar is added to the system, a higher percentage of the LOLE will occur in the winter because the output of solar in the summer during peak load hours, which occur in the afternoon and early evening, is naturally higher than the output during the winter peak load hours which occur early in the morning or late in the evening. In other words, when 1 MW of nameplate solar is added to the system, the 1 MW of solar reduces summer LOLE more than it reduces winter LOLE, thereby further shifting the seasonal weighting of LOLE more to the winter. This is apparent by examining the LOLE results in the table. The DEP no solar scenario has a seasonal LOLE weighting of approximately 85% winter and 15% summer. DEP has a significant level of Existing Plus Transition solar which pushes the seasonal winter LOLE weighting to greater than 99%. Thus, solar levels greater than Existing Plus Transition for DEP will have solar capacity values based solely on their capacity contribution in the winter.

Table 9-B: DEP Seasonal LOLE Percentage

	DEP Incremental Solar MW	DEP Cumulative Solar MW	DEP LOLE Summer %	DEP LOLE Winter %
0 MW Level	-	-	14.7%	85.3%
Existing Plus Transition MW	2,950	2,950	0.6%	99.4%
Tranche 1	160	3,110	0.5%	99.5%
Tranche 2	180	3,290	0.4%	99.6%
Tranche 3	160	3,450	0.3%	99.7%
Tranche 4	135	3,585	0.3%	99.7%

Table 9-C shows the solar capacity value results for DEP. The table illustrates the declining capacity value of solar as greater amounts of solar resources are added to the system. The first MW of solar in DEP provides only a 7% annual capacity value because of the high winter season LOLE weighting.[4] The Existing Plus Transition solar has an annual capacity value of less than 1%. The table also shows slightly greater capacity values for tracking versus fixed solar arrays.

[4] Capacity values represent the incremental capacity value of the next MW given the referenced solar penetration. The average capacity contribution for an entire block of solar resources can be estimated by averaging the incremental value for the first MW of the block and the incremental value for the first MW of the next block.

Table 9-C: DEP Capacity Value Results by Solar Penetration

Solar Capacity at Each Penetration Level (Incremental MW)	Solar Capacity at Each Penetration Level (Cumulative MW)	Penetration Level	Winter	Summer	Annual
0	0	DEP - 0 Solar	1.2%	35.4%	7.2%
2,950	2,950	DEP - 2950 Existing + Transition	0.6%	12.4%	0.6%
160	3,110	DEP - Tranche 1 – Fixed	0.3%	12.2%	0.3%
180	3,290	DEP - Tranche 2 – Fixed	0.3%	11.6%	0.3%
160	3,450	DEP - Tranche 3 – Fixed	0.2%	8.8%	0.3%
135	3,585	DEP - Tranche 4 – Fixed	0.2%	8.2%	0.3%
160	3,110	DEP - Tranche 1–Tracking	3.2%	22.3%	3.2%
180	3,290	DEP - Tranche 2–Tracking	3.1%	20.6%	3.1%
160	3,450	DEP - Tranche 3–Tracking	2.8%	16.2%	2.9%
135	3,585	DEP – Tranche 4–Tracking	2.7%	15.3%	2.8%

In summary, the winter LOLE to summer LOLE ratio drives the annual solar equivalent capacity values. Because the company has higher winter LOLE values in hours when solar is not available, the resulting equivalent annual solar capacity values are significantly reduced. As solar penetration increases, the capacity values decrease further since the firm load shed events are shifted even further into hours when there is less solar output. However, single-axis-tracking resources do bring some additional capacity value compared to fixed-tilt resources due to more output in morning and evening hours.

10. NUCLEAR AND SUBSEQUENT LICENSE RENEWAL (SLR)

Nuclear Assumptions in the 2018 IRP:

With respect to nuclear generation overall, the Company will continue to monitor and analyze key developments on factors impacting the potential need for, and viability of, future new baseload nuclear generation. Such factors include further developments on the Vogtle project and other new reactor projects worldwide, progress on existing unit relicensing efforts, nuclear technology developments, and changes in fuel prices and carbon policy.

Subsequent License Renewal (SLR) for Nuclear Power Plants:

DEP and DEC, collectively, provide approximately one half of all energy served in their SC and NC service territories from clean carbon-free nuclear generation. This highly reliable source of generation provides power around the clock every day of the year. While nuclear unit outages are needed for maintenance and refueling, outages are generally relatively short in duration and are spread across the nuclear fleet in months of lower power demand. In total, the fleet has a capacity factor, or utilization rate, of well over 90% with some units achieving 100% annual availability depending on refueling schedules. Nuclear generation is foundational to Duke's commitment to providing affordable, reliable electricity while also reducing the carbon footprint of its resource mix. Currently, all units within the fleet have operating licenses from the Nuclear Regulatory Commission (NRC) that allow the units to run 60 years from their original license date.

License Renewal is governed by Title 10 of the Code of Federal Regulations (10 CFR) Part 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants.* Currently NRC has approved applications to extend licenses to up to 60 years for 89 nuclear units across the country, with applications for four nuclear units currently under review.

SLR would cover a second license renewal period, for a total of as much as 80 years. The NRC has issued regulatory guidance documents, NUREG-2191 [Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report] and NUREG-2192 [Standard Review Plan for the Review of Subsequent License Renewal (SRP-SLR) Applications for Nuclear Power Plants], establishing formal regulatory guidance for SLR.

NextEra submitted the industry's first SLR application to the NRC on January 31, 2018 for its Turkey Point station. The SLR application was accepted by NRC as sufficient for review allowing the NRC to begin their comprehensive review of the application. The NRC review is expected to take 18 months not including the time needed to perform the sufficiency review.

On July 10, 2018, Exelon Corporation submitted an SLR application for its Peach Bottom plant. The NRC is currently performing the sufficiency review of the Peach Bottom SLR application with a decision expected 3Q2018. Dominion Energy announced it would pursue SLR for its Surry and North Anna plants targeting an SLR application submittal to the NRC in early-2019 for Surry and 2020 for North Anna.

Based on recent industry progress in SLR, including published NRC guidance, the NextEra and Exelon Corporation application submittals, and announcements from Dominion Energy, the Company's Base Cases assume SLR for existing nuclear generation to 80 years for planning purposes in this year's IRP. The Company will continue to monitor industry and NRC developments related to SLR.

The Company views all its existing nuclear fleet as excellent candidates for SLR based on current conditions and expected operating expenditures, regardless of future carbon constraints. Duke Energy intends to pursue SLR for all its nuclear plants that show benefit for the customer. Work continues on development of the Oconee Nuclear Station SLR.

11. COMBINED HEAT AND POWER

Combined Heat and Power (CHP) 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 gas-fired combustion turbine (CT) and heat recovery steam generator (HRSG) is more efficient than the conventional method of producing power and usable heat separately with a CT/generator and a stand-alone steam boiler.

Duke Energy is exploring and working with potential customers with continuous large thermal loads on a regulated CHP offer. The CHP asset is included as part of Duke Energy's IRP as a placeholder for future projects as described below. The steam sales revenue would be credited back to the revenue requirement of the projects to reduce the total cost of this resource. Along with the potential to be a cost-competitive generation resource, CHP would result in CO_2 emission reductions, and is an economic development opportunity for the state. In DEP, discussions with a potential steam host are currently underway.

Projections for CHP have been included in the following quantities in this IRP:

2021: 22 MW (winter)

As CHP development continues, future IRPs will incorporate additional CHP, as appropriate.
Additional technologies evaluated as part of this IRP are discussed in Chapter 7 and Appendix F.

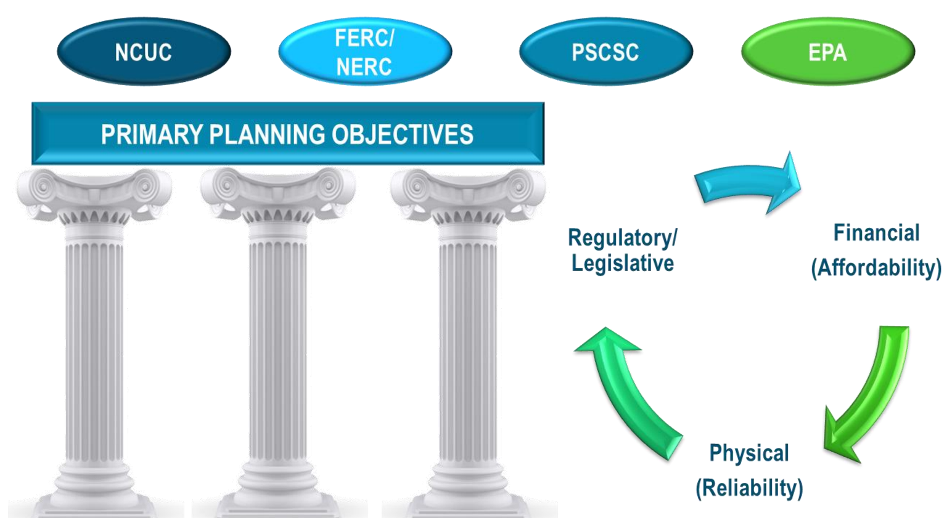
12. EVALUATION AND DEVELOPMENT OF THE RESOURCE PLAN

As described in Chapter 8, DEP continues to plan to winter planning reserve margin criteria in 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 Cases and five alternative portfolios as discussed later in this chapter and in Appendix A.

Three Pillars of the IRP:

The IRP process has evolved as the energy industry has changed. While the intent of the IRP remains to develop a 15-year plan that is reliable and economical to meet future customer demand, other factors also must be considered when selecting a plan.

Figure 12-A: Three Pillars of the IRP



There are three pillars which determine the primary planning objectives in the IRP. These pillars are as follows:

- Regulatory/Legislative
- Financial (Affordability)
- Physical (Reliability)

The Regulatory and Legislative pillar of the IRP process takes into consideration various policies set by state and federal entities. Such entities include PSCSC, NCUC, FERC, NERC, SERC, NRC, and EPA, along with various other state and federal regulatory entities. Each of these entities develops policies that have a direct bearing on the inputs, analysis and results of the IRP process. Examples of such policies include the SC DER program and NC HB 589, which set targets for the addition of renewable resources. Environmental legislation at the state and federal level can impact the cost and operations of existing resources as well as future assets. In addition, reliability and operational requirements imposed on the system also influence the IRP process.

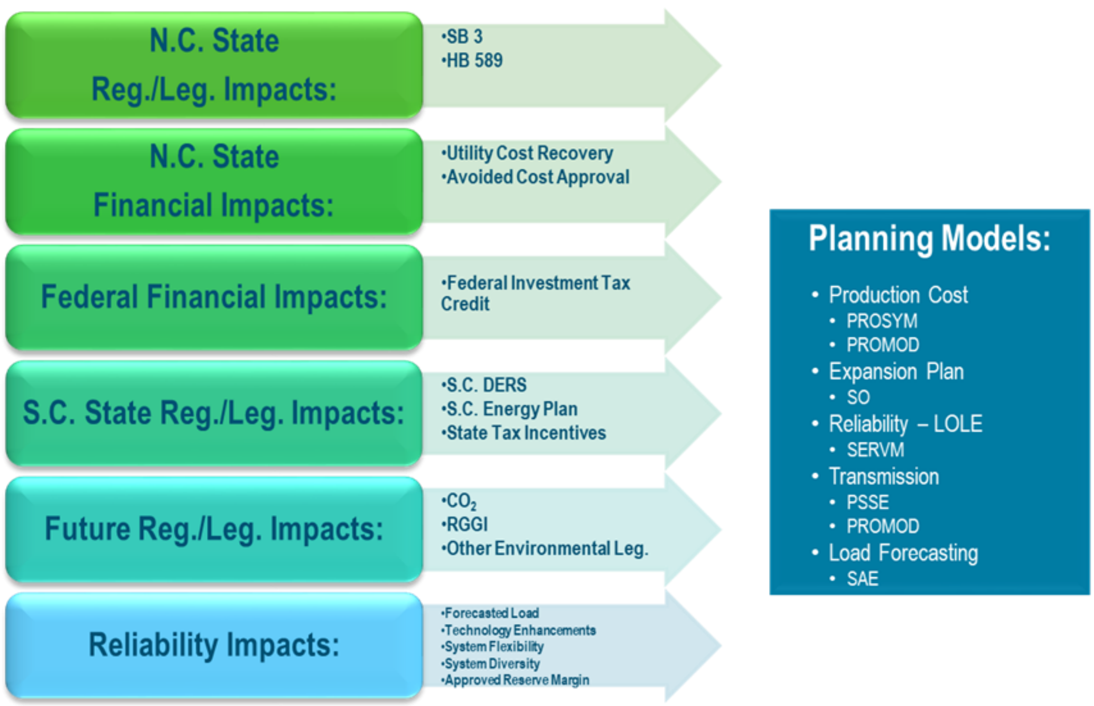
The Financial, or Affordability, pillar is another basic criterion for the IRP. The plan that is selected must be cost-effective for the customers of the Company. DEP's service territory, located in the southern United States, has climate conditions that require more combined electric heating and cooling per customer than any other region in the country. As such, DEP's customers require more electricity than customers from other regions, highlighting the need for affordable power. Changing customer preferences and usage patterns will continue to influence the load forecast incorporated in the Company's IRPs. Furthermore, as new technologies are developed and continue to evolve, the costs of these technologies are projected to decline. These downward impacts are contemplated in the planning process and changes to those projections will be closely monitored and captured in future IRPs.

Finally, Physical Reliability is the third pillar of the IRP process. Reliability of the system is vitally important to meeting the needs of today's customers as well as the future needs that comes with substantial customer growth projected in the region. DEP's customers expect energy to be provided to them when they need it both today and into the future. As discussed previously, the addition of new types of generation has impacted the operation of the system. As such, different ways of managing the system operations to ensure the Company reliably meets customer demand have been incorporated. The Company continues to plan to a reasonable 17% reserve margin, which helps to ensure that the reliability of the system is maintained.

Each of these pillars must be evaluated and balanced in the IRP in order to meet the intent of the process. The Company has adhered to the principles of these pillars in the development of this IRP and the portfolios evaluated as part of the IRP process.

Figure 12-B below graphically represents examples of how issues from each of the pillars may impact the IRP modeling process and subsequent portfolio development.

Figure 12-B: Impacts of Three Pillars on the IRP Modeling Process



IRP Analysis 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 Cases and additional portfolios is provided in Appendix A.

Data Inputs:

Refreshing input data is the initial step in the IRP development process. For the 2018 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 Forecast
- Renewable Resources and Cost Projections
- Fuel Costs Forecasts
- Technology Costs and Operating Characteristics
- Environmental Legislation and Regulation

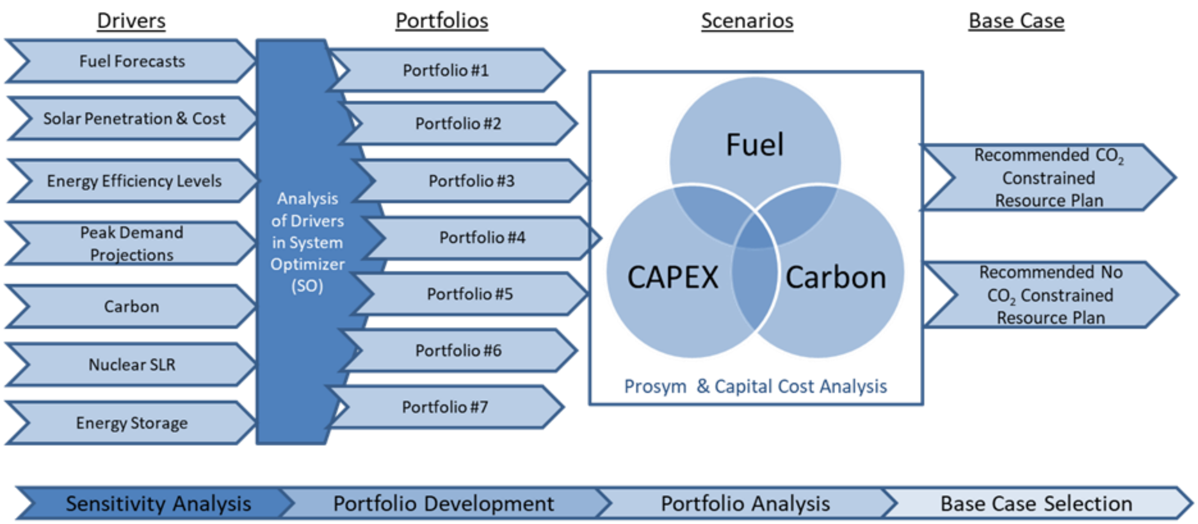
Generation Alternative Screening:

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 12-C: 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, System Optimizer (SO), 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 meets reliability targets and minimizes the PVRR to customers and is environmentally sound by complying with or exceeding, 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 under varying input assumptions. After this comprehensive analysis is completed, the Base Case portfolios are 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 2018 IRP, seven representative portfolios were identified through the Sensitivity Analysis and Portfolio Development steps. As described below, the portfolios range from diverse portfolios with varying fuel sources such as nuclear, solar, natural gas, and coal, to more technology concentrated resources such as CT Centric and CC Centric resources. Additionally, some portfolios increase the amount and adoption rate of renewables, EE, and energy storage.

<u>Portfolio 1 (Base CO_2 Future)</u>

This portfolio represents a balanced generation portfolio with CCs and CTs making up the generation mix with incremental solar additions just beyond the 15-year window. While CCs are the preferred initial generating options in both DEP and DEC, CTs make up the vast majority of additional resources at the end of the 15-year planning horizon. This portfolio also includes base EE and renewable assumptions, along with 1,000 MW of economically selected solar just beyond the planning horizon. Additionally, 140 MW of nameplate battery storage placeholders are included. These placeholders represent a limited amount of grid connected battery storage projects that have the potential to provide solutions for the transmission and distribution systems with the possibility of simultaneously providing benefits to the generation resource portfolio.

<u>Portfolio 2 (Base No CO_2 Future)</u>

Within the 15-year planning horizon, this portfolio is the same as Portfolio 1. Beyond the planning window, CT technology generally takes precedence over CC technology. No additional solar was selected in this portfolio. The Base No CO_2 portfolio also includes base EE and renewable assumptions, along with 140 MW of nameplate battery storage placeholders.

<u>Portfolio 3 (CT Centric)</u>

This portfolio is similar to Portfolio 2. However, the 2027 CC need is replaced with CT technology to increase the concentration of CTs in this portfolio. Like Portfolio 2, this portfolio includes base EE and renewable assumptions, and no additionally selected solar. The portfolio includes 140 MW of nameplate storage placeholders.

<u>Portfolio 4 (CC Centric – No Nuclear Future)</u>

This portfolio represents a future where all existing nuclear assets are retired at the end of their current extended license period, and those nuclear assets are primarily replaced with CCs rather than new nuclear generation. The CC Centric Portfolio converts the entire 2029

CT block to CC technology. This portfolio also includes base EE and renewable assumptions, along with 1,000 MW of economically selected solar just beyond the planning horizon. Additionally, 140 MW of nameplate battery storage placeholders are included.

<u>Portfolio 5 (High EE / High Renewables)</u>

This portfolio includes the High EE and High Renewable assumptions in DEP. Solar nameplate capacity increases at a more rapid pace, and the total MW of solar is 310 MW greater in the High Renewable case by 2033. This portfolio includes an additional 124 MW of EE by the end of the planning horizon. Finally, this case also includes 140 MW of nameplate battery storage placeholders.

<u>Portfolio 6 (CT Centric / High Renewables)</u>

Like Portfolio 3, Portfolio 6 includes a high concentration of CT generation in the 15-year planning horizon. However, this portfolio includes the High Renewable assumption which accelerates solar additions in DEP while increasing the total amount of solar by approximately 300 MW. Portfolio 6 includes Base EE assumptions along with a placeholder of 140 MW of nameplate battery storage. This portfolio is especially illustrative when evaluating additional energy storage added in Portfolio 7.

<u>Portfolio 7 (CT Centric with Battery Storage and High Renewables)</u>

This portfolio converts the first 460 MW block of CTs in Portfolio 6 to 575 MW (nameplate) of 4-hour Lithium-ion battery storage in 2029. The additional 575 MW of battery storage is assumed to only provide generation and energy transfer capability that is 100% controlled by the Company. As such, the battery storage installation is assumed to provide 460 MW of winter peak capacity. The total amount of nameplate battery storage in DEP in this case is 715 MW by 2029.

Portfolio Analysis & Base Case Selection:

The seven portfolios identified in the screening analysis were evaluated in more detail with an hourly production cost model under a matrix of nine carbon and fuel cost scenarios. Additionally, each of the portfolios were further studied under high and low capital cost scenarios to determine how changing capital costs impacted their relative value under the varying fuel and carbon scenarios. Table 12-A shows the matrix that each of the scenarios were tested under.

Table 12-A Scenarios for Portfolio Analysis

	No CO_2	Base CO_2	High CO_2
Low Fuel			
Base Fuel			
High Fuel			

Table 12-B details the results of the PVRR analysis under the varying carbon and fuel scenarios while Tables 12-C and 12-D provide the same results but under low capital cost and high capital cost futures respectively.

Table 12-B: Lowest PVRR (thru 2068) Portfolios Under Each Scenario (2018 dollars in Millions)

PVRR thru 2068 (2018 $M)	No CO_2	Base CO_2	High CO_2
Low Fuel	Portfolio 2 (-$132 M vs Port 3)	Portfolio 1 (-$84 M vs Port 2)	Portfolio 1 (-$409 M vs Port 2)
Base Fuel	Portfolio 2 (-$17 M vs Port 1)	Portfolio 1 (-$231 M vs Port 2)	Portfolio 1 (-$536 M vs Port 5)
High Fuel	Portfolio 1 (-$257 M vs Port 2)	Portfolio 1 (-$493 M vs Port 2)	Portfolio 1 (-$533 M vs Port 5)

Table 12-C: Lowest PVRR (thru 2068) Portfolios Under Each Scenario – Low Capital Cost Sensitivity (2018 dollars in Millions)

PVRR thru 2068 (2018 $M)	No CO_2	Base CO_2	High CO_2
Low Fuel	Portfolio 2 (-$6 M vs Port 1)	Portfolio 1 (-$260 M vs Port 2)	Portfolio 1 (-$586 M vs Port 5)
Base Fuel	Portfolio 1 (-$60 M vs Port 2)	Portfolio 1 (-$408 M vs Port 2)	Portfolio 1 (-$579 M vs Port 5)
High Fuel	Portfolio 1 (-$351 M vs Port 7)	Portfolio 1 (-$551 M vs Port 5)	Portfolio 1 (-$552 M vs Port 5)

Table 12-D: Lowest PVRR (thru 2068) Portfolios Under Each Scenario – High Capital Cost Sensitivity (2018 dollars in Millions)

PVRR thru 2068 (2018 $M)	No CO_2	Base CO_2	High CO_2
Low Fuel	Portfolio 2 (-$137 M vs Port 3)	Portfolio 2 (-$44 M vs Port 2)	Portfolio 1 (-$282 M vs Port 2)
Base Fuel	Portfolio 2 (-$144 M vs Port 1)	Portfolio 1 (-$104 M vs Port 2)	Portfolio 1 (-$409 M vs Port 2)
High Fuel	Portfolio 1 (-$129 M vs Port 2)	Portfolio 1 (-$366 M vs Port 2)	Portfolio 1 (-$448 M vs Port 5)

Carbon Constrained Base Case:

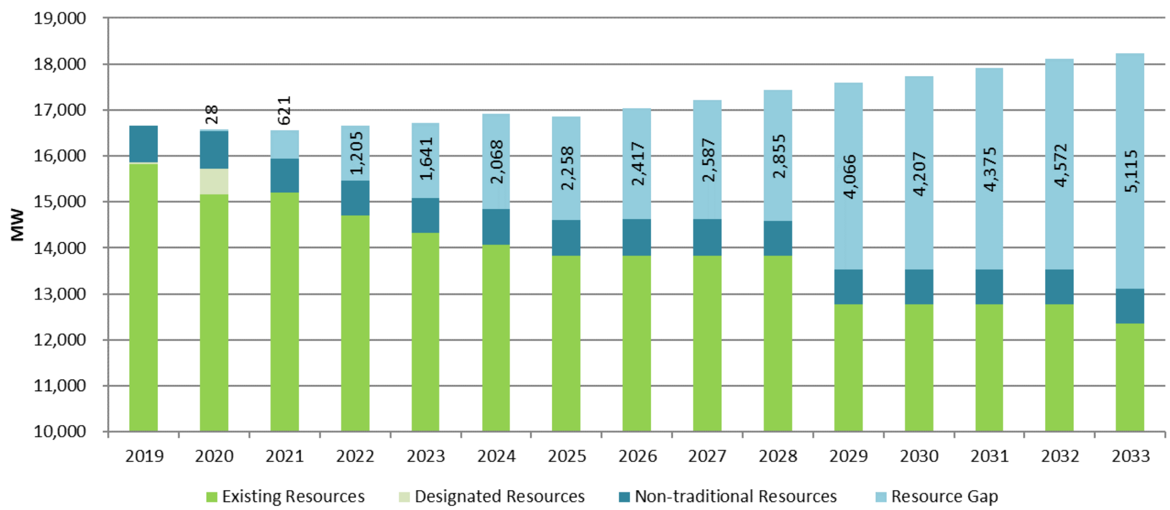
For planning purposes, Duke Energy considers a carbon constrained future and a no carbon future in the development of the Base Case portfolios. If a carbon constrained future is either delayed or is more restrictive than the base plan, or other variables such as fuel price and capital costs change significantly from the base assumptions, the selected carbon constrained portfolio should be adequately robust to still provide value in those futures. Another factor that is considered when selecting the base portfolio is the likelihood that the selected portfolio can be executed as shown. Under those considerations, the Company selected Portfolio 1 (Base CO_2 Future) as the base portfolio for planning assumptions.

Portfolio 1 includes a diverse compilation of resources including CCs, CTs, battery storage, and increasing amounts of EE/DSM and solar resources in conjunction with existing nuclear, natural gas, renewables and other assets already on the DEP system. This portfolio also enables the Company to lower carbon emissions under a range of future scenarios at a lower cost than most other scenarios.

Finally, the Carbon Constrained Base Case was developed utilizing consistent assumptions and analytic methods between DEP and DEC, where appropriate. This case does not consider 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 explores 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 shown in Figure 12-D illustrates the resource needs that are required for DEP to meet its load obligation inclusive of a required reserve margin. The existing generating resources, designated resource additions and EE resources do not meet the required load and reserve margin beginning in 2020. As a result, the resource plan analyses described above have determined the most robust plan to meet this resource gap.

Figure 12-D: DEP Carbon Constrained Base Case Load Resource Balance (Winter)



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

Year	2019	2020	2021	2022	2023	2024	2025	2026
Resource Need	0	28	621	1,205	1,641	2,068	2,258	2,417
Year	2027	2028	2029	2030	2031	2032	2033	
Resource Need	2,587	2,855	4,066	4,207	4,375	4,572	5,115	

Tables 12-E and 12-F present the Load, Capacity and Reserves (LCR) tables for the Carbon Constrained Base Case analysis that was completed for DEP's 2018 IRP.

Table 12-E: Carbon Constrained Load, Capacity and Reserves Table -Winter

Winter Projections of Load, Capacity, and Reserves
for Duke Energy Progress 2018 Annual Plan

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Load Forecast															
1 DEP System Winter Peak	14,036	14,060	14,062	14,168	14,243	14,429	14,553	14,724	14,886	15,090	15,232	15,367	15,524	15,704	15,811
2 Firm Sale	150	150	150	150	150	150	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(26)	(44)	(62)	(79)	(104)	(120)	(138)	(155)	(173)	(187)	(200)	(211)	(221)	(229)	(236)
4 Adjusted Duke System Peak	**14,161**	**14,166**	**14,151**	**14,239**	**14,289**	**14,458**	**14,415**	**14,568**	**14,713**	**14,903**	**15,032**	**15,155**	**15,303**	**15,475**	**15,575**
Existing and Designated Resources															
5 Generating Capacity	13,912	13,942	14,124	13,614	13,620	13,620	13,626	13,394	13,394	13,394	13,398	12,345	12,345	12,345	12,345
6 Designated Additions / Uprates	30	566	4	6	0	6	0	0	0	4	0	0	0	0	0
7 Retirements / Derates	0	(384)	(514)	0	0	0	(232)	0	0	0	(1,053)	0	0	0	0
8 Cumulative Generating Capacity	**13,942**	**14,124**	**13,614**	**13,620**	**13,620**	**13,626**	**13,394**	**13,394**	**13,394**	**13,398**	**12,345**	**12,345**	**12,345**	**12,345**	**12,345**
Purchase Contracts															
9 Cumulative Purchase Contracts	**2,013**	**1,703**	**1,646**	**1,140**	**738**	**480**	**480**	**479**	**476**	**470**	**466**	**465**	**465**	**463**	**35**
Non-Compliance Renewable Purchases	99	102	48	49	38	40	39	39	36	33	29	28	27	26	26
Non-Renewables Purchases	1,914	1,601	1,599	1,091	700	440	440	440	440	437	437	437	437	437	9
Undesignated Future Resources															
10 Nuclear															
11 Combined Cycle							1,338		1,338						
12 Combustion Turbine											1,840			460	460
13 Short-Term Market Purchases		30	590	590	430	430	(30)	(590)	(590)	(430)	(430)				
14 Solar															
Renewables															
15 Cumulative Renewables Capacity	194	194	106	102	102	102	74	74	72	22	15	16	16	16	16
16 Combined Heat & Power	0	0	22	0	0	0	0	0	0	0	0	0	0	0	0
17 Energy Storage	12	12	12	14	14	16	16	16	0	0	0	0	0	0	0
18 Cumulative Production Capacity	**16,161**	**16,075**	**16,045**	**16,144**	**16,187**	**16,381**	**17,445**	**16,870**	**17,613**	**17,131**	**17,477**	**17,477**	**17,477**	**17,935**	**17,967**
Demand Side Management (DSM)															
19 Cumulative DSM Capacity	**490**	**501**	**511**	**521**	**530**	**537**	**541**	**546**	**550**	**557**	**560**	**564**	**569**	**574**	**578**
20 Cumulative Capacity w/ DSM	**16,651**	**16,576**	**16,555**	**16,665**	**16,718**	**16,918**	**17,985**	**17,416**	**18,163**	**17,687**	**18,038**	**18,041**	**18,046**	**18,509**	**18,544**
Reserves w/ DSM															
21 Generating Reserves	2,491	2,410	2,405	2,426	2,428	2,460	3,571	2,848	3,450	2,784	3,006	2,886	2,743	3,034	2,969
22 % Reserve Margin	**17.6%**	**17.0%**	**17.0%**	**17.0%**	**17.0%**	**17.0%**	**24.8%**	**19.5%**	**23.4%**	**18.7%**	**20.0%**	**19.0%**	**17.9%**	**19.6%**	**19.1%**

Table 12-F: Carbon Constrained Load, Capacity and Reserves Table - Summer

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Progress 2018 Annual Plan

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Load Forecast															
1 DEP System Summer Peak	13,374	13,409	13,439	13,557	13,676	13,850	14,018	14,264	14,398	14,642	14,804	14,959	15,137	15,333	15,463
2 Firm Sale	150	150	150	150	150	150	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(58)	(87)	(115)	(141)	(166)	(193)	(222)	(250)	(280)	(306)	(332)	(354)	(375)	(392)	(409)
4 Adjusted Duke System Peak	**13,467**	**13,472**	**13,474**	**13,566**	**13,660**	**13,808**	**13,796**	**14,014**	**14,118**	**14,336**	**14,473**	**14,605**	**14,762**	**14,941**	**15,054**
Existing and Designated Resources															
5 Generating Capacity	12,728	12,732	12,852	12,477	12,477	12,481	12,481	12,305	12,305	12,307	12,307	11,260	11,260	11,260	11,260
6 Designated Additions / Uprates	4	498	4	0	4	0	0	0	2	0	0	0	0	0	0
7 Retirements / Derates	0	(378)	(379)	0	0	0	(176)	0	0	0	(1,047)	0	0	0	0
8 Cumulative Generating Capacity	**12,732**	**12,852**	**12,477**	**12,477**	**12,481**	**12,481**	**12,305**	**12,305**	**12,307**	**12,307**	**11,260**	**11,260**	**11,260**	**11,260**	**11,260**
Purchase Contracts															
9 Cumulative Purchase Contracts	**2,207**	**2,170**	**1,705**	**1,445**	**1,461**	**1,262**	**1,278**	**1,268**	**1,256**	**1,242**	**1,229**	**1,219**	**1,215**	**1,208**	**809**
Non-Compliance Renewable Purchases	611	719	741	818	835	856	871	862	850	838	825	816	811	805	800
Non-Renewables Purchases	1,596	1,451	964	626	626	406	406	406	406	403	403	403	403	403	9
Undesignated Future Resources															
10 Nuclear															
11 Combined Cycle							1,198		1,198						
12 Combustion Turbine											1,704			426	426
13 Short Term Market Purchases		30	590	590	430	430	(30)	(590)	(590)	(430)	(430)				
14 Solar															
Renewables															
15 Cumulative Renewables Capacity	620	618	537	528	539	535	499	511	521	482	488	499	504	509	514
16 Combined Heat & Power	0	0	16	0	0	0	0	0	0	0	0	0	0	0	0
17 Energy Storage	12	12	12	14	14	16	16	16	0	0	0	0	0	0	0
18 Cumulative Production Capacity	**15,571**	**15,694**	**15,391**	**15,726**	**16,202**	**16,445**	**17,432**	**16,861**	**17,469**	**16,986**	**17,205**	**17,207**	**17,208**	**17,633**	**17,665**
Demand Side Management (DSM)															
19 Cumulative DSM Capacity	**923**	**958**	**984**	**1,007**	**1,019**	**1,024**	**1,027**	**1,032**	**1,035**	**1,041**	**1,044**	**1,047**	**1,051**	**1,055**	**1,058**
20 Cumulative Capacity w/ DSM	**16,494**	**16,652**	**16,375**	**16,733**	**17,221**	**17,469**	**18,459**	**17,893**	**18,504**	**18,026**	**18,249**	**18,254**	**18,259**	**18,688**	**18,723**
Reserves w/ DSM															
21 Generating Reserves	3,027	3,180	2,901	3,167	3,561	3,662	4,663	3,879	4,385	3,690	3,776	3,650	3,496	3,747	3,669
22 % Reserve Margin	**22.5%**	**23.6%**	**21.5%**	**23.3%**	**26.1%**	**26.5%**	**33.8%**	**27.7%**	**31.1%**	**25.7%**	**26.1%**	**25.0%**	**23.7%**	**25.1%**	**24.4%**

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 new 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 July 1, 2018.

6. Designated Capacity Additions include:

   Planned nuclear uprates totaling 56 MW in the 2019 - 2028 timeframe.

   560 MW Asheville combined cycle addition in November 2019.

7. Planned Retirements include:

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

   514 MW Darlington CT Units 1-4, 6-8, 10 by December 2020.

   232 MW Blewett CT Units 1-4 and Weatherspoon CT units 1-4 in December 2024.

   1,053 MW Roxboro Units 1-2 in December 2028.

   Planning assumptions for nuclear stations assume subsequent license renewal at the end of the current license. 797 MW Robinson 2 is assumed to be relicensed to 2050 (current license expires in 2030).

   All retirement dates are subject to review on an ongoing basis. Dates used in the 2018 IRP are for planning purposes only, unless already planned for retirement.

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

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.

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 following 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 1,338 MW of combined cycle capacity online December 2024

    Addition of 1,338 MW of combined cycle capacity online December 2026.

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 1,840 MW of combustion turbine capacity online December 2028.

    Addition of 460 MW of combustion turbine capacity online December 2031.

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

Addition of 460 MW of combustion turbine capacity online December 2032.

13. Short-term market purchases needed to meet load and minimum planning reserve margin.

14. New solar resources economically selected to meet load and minimum planning reserve margin above the forecast in Section 5.

    No solar resources were economically selected in the Base Case.

15. Resources to comply with NC REPS, HB 589 and SC DERS. These resources include solar, landfill gas, poultry and swine resources. Solar resources reflect percentage of nameplate capacity contribution at the time of the winter and summer peak demands.

16. New 22 MW combined heat and power capacity included in 2021.

17. Addition of 113 MW of energy storage placeholders over the years 2019 through 2026 based on 80% contribution to peak assumption.

18. Sum of lines 8 through 17.

19. Cumulative Demand-Side Management programs including load control and DSDR.

20. Sum of lines 18 and 19.

21. The difference between lines 20 and 4.

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

    Line 21 divided by Line 4.

    Minimum target planning reserve margin is 17%.

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

Table 12-G: DEP Carbon Constrained Base Case

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

Year	Resource				MW			
2019	Nuclear Uprates	Solar	Energy Storage		30	190	12	
2020	Nuclear Uprates	Asheville CC	Solar	Energy Storage	6	560	303	12
2021	Nuclear Uprates	CHP	Solar	Energy Storage	4	22	280	12
2022	Nuclear Uprates	Solar	Energy Storage		6	247	14	
2023	Solar	Energy Storage			172	14		
2024	Nuclear Uprates	Energy Storage	Solar		6	16	179	
2025	New CC	Energy Storage	Solar		1,338	16	80	
2026	Energy Storage	Solar			16	34		
2027	New CC	Solar			1,338	34		
2028	Nuclear Uprates	Solar			4	34		
2029	New CT	Solar			1,840	33		
2030	Solar				33			
2031	Solar				4			
2032	New CT	Solar			460	4		
2033	New CT	Solar			460	4		

Notes: (1) Table includes both designated and undesignated capacity additions
(2) Incremental solar additions represent nameplate ratings
(3) Future additions of other renewables, EE and DSM not included
(4) Table does not include short term PPA purchases in 2020 through 2024

Additionally, a summary of the above table is represented below in Table 12-H.

Table 12-H: Summary of DEP Carbon Constrained Base Case Winter Resources

DEP Base Case Resources
Cumulative Winter Totals - 2019 - 2033

Nuclear	56
Solar	1,631
CC	3,236
CT	2,760
CHP	22
Energy Storage	113
Total	7,817

The following figures illustrate both the current and forecasted capacity for the DEP system, as projected by the Carbon Constrained Base Case. As demonstrated in Figure 12-E, the capacity mix for the DEP system changes with the passage of time. In 2033, the Carbon Constrained 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 Carbon Constrained Base Case resources depicted in Figure 13-E below reflect a significant amount of solar capacity with nameplate solar growing from 2,758 MW in 2019 to 4,199 MW by 2033. However, given that solar resources only contribute 1% or less of nameplate capacity at the time of the Company's winter peak, solar capacity contribution to winter peak only grows from 28 MW in 2019 to 42 MW by 2033.

Figure 12-E: Duke Energy Progress Capacity Over 15 Year Study Period – Carbon Constrained Base Case [5]

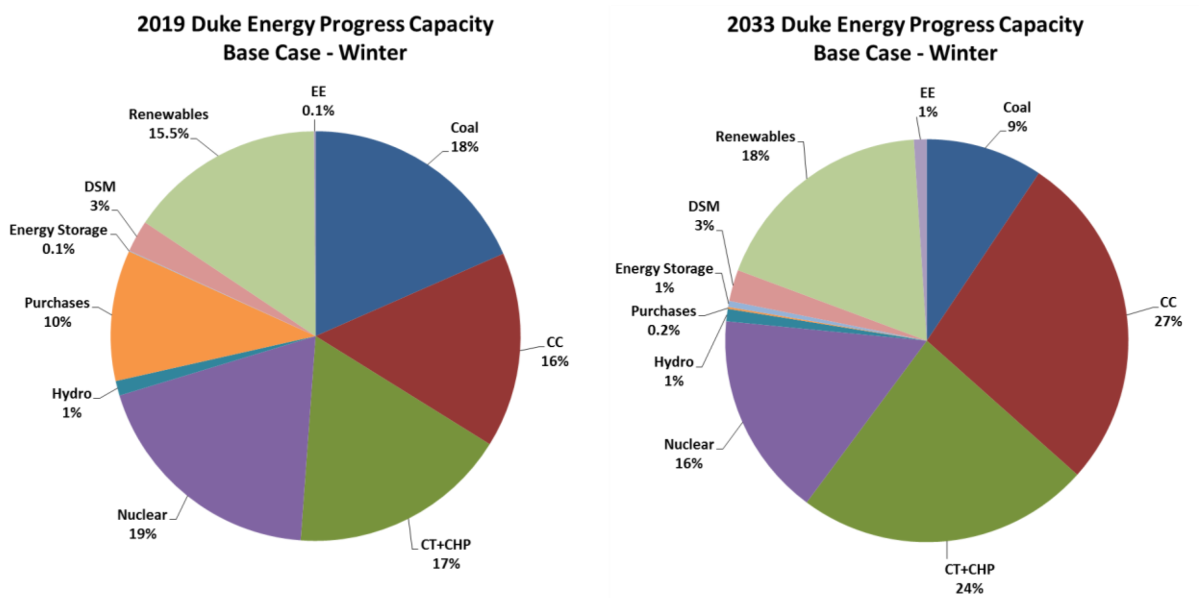
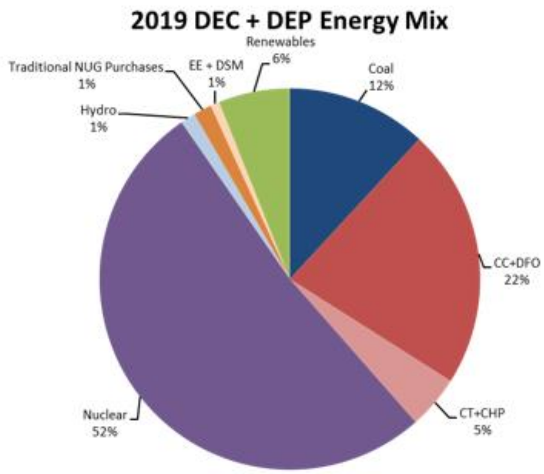
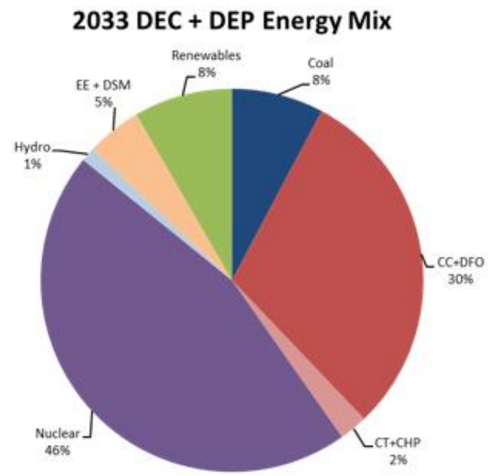


Figure 12-F represents the energy of both the DEP and DEC Carbon Constrained Base Cases over time. Due to the joint dispatch agreement (JDA), it is prudent to combine the energy of both utilities to develop a meaningful Carbon Constrained Base Case energy figure. From 2019 to 2033, the figure shows that 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.

[5] Capacity based on winter ratings (renewables based on nameplate).

Figure 12-F: DEP and DEC Energy Over 15 Year Study Period – Carbon Constrained Base Case





A detailed discussion of the assumptions, inputs and analytics used in the development of the Base Cases are contained in Appendix A. As previously noted, the further out in time planned additions or retirements are within the 2018 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.

No Carbon Base Case:

While Duke Energy presents a base resource plan that was developed under a carbon constrained future, the Company also provides a No Carbon (or No CO_2) Base Case expansion plan that reflects a future without CO_2 constraints. In DEP, this expansion plan is represented by Portfolio 2 (Base No CO_2 Future). As shown in Tables 12-I and 12-J below, there is no difference between the Carbon Constrained Base Case and the No Carbon Base Case over the 15-year planning horizon. However, beyond the 15-year window, CT technology generally takes precedence over CC technology. Because of the trend towards CT technology and the absence of incremental solar in the years just after the planning window, Portfolio 2 has a lower capital cost and a slightly lower PVRR than Portfolio 1 in the Base Fuel / No CO_2 scenario.

The tables below depict a tabular form of the resources required in the No Carbon Base Case.

Table 12-I: DEP No Carbon Base Case

Duke Energy Progress Resource Plan [1]
No CO_2 Case - Winter

Year	Resource				MW			
2019	Nuclear Uprates	Solar	Energy Storage		30	190	12	
2020	Nuclear Uprates	Asheville CC	Solar	Energy Storage	6	560	303	12
2021	Nuclear Uprates	CHP	Solar	Energy Storage	4	22	280	12
2022	Nuclear Uprates	Solar	Energy Storage		6	247	14	
2023	Solar	Energy Storage			172	14		
2024	Nuclear Uprates	Energy Storage	Solar		6	16	179	
2025	New CC	Energy Storage	Solar		1,338	16	80	
2026	Energy Storage	Solar			16	34		
2027	New CC	Solar			1,338	34		
2028	Nuclear Uprates	Solar			4	34		
2029	New CT	Solar			1,840	33		
2030	Solar				33			
2031	Solar				4			
2032	New CT	Solar			460	4		
2033	New CT	Solar			460	4		

Notes: (1) Table includes both designated and undesignated capacity additions
(2) Incremental solar additions represent nameplate ratings
(3) Future additions of other renewables, EE and DSM not included
(4) Table does not include short term PPA purchases in 2020 through 2024

Additionally, a summary of the above table is represented below in Table 12-J.

Table 12-J: Summary of DEP No Carbon Base Case Winter Resources

DEP No CO_2 Case Resources
Cumulative Winter Totals – 2019 - 2033

Nuclear	56
Solar	1,631
CC	3,236
CT	2,760
CHP	22
Energy Storage	113
Total	7,817

Joint Planning Case:

A Joint Planning Case that explores 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 12-K 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 12-K, the Joint Planning Case allows for the delay of a CC resource and several blocks of CT resources through the 15-year study period. Though not shown below, the ability to share capacity between DEP and DEC would also limit the amount of undesignated short-term market purchases identified in the 2020 to 2024 timeframe in the DEP IRP.

Table 12-K: DEP and DEC Joint Planning Case

DEC and DEP Combined Resource Plan [1] Base Case - Winter		
Year	**Resource**	**MW**
2019		
2020		
2021		
2022		
2023		
2024		
2025	New CC	1,338
2026		
2027	New CC	1,338
2028	New CC	1,338
2029	New CT	1,840
2030		
2031	New CC	1,338
2032	New CT	460
2033	New CT	920

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

Delay

Delay 460 MW

Delay 460 MW

Delay 460 MW Beyond Study Period

DEC and DEP Joint Planning Resource Plan [1] Base Case - Winter				
Year	**Resource**		**MW**	
2019				
2020				
2021				
2022				
2023				
2024				
2025	New CC		1,338	
2026				
2027	New CC		1,338	
2028				
2029	New CC	New CT	1,338	1,380
2030				
2031	New CC		1,338	
2032				
2033	New CT		1,380	

A comparison of both the DEP and DEC Combined Base Case and Joint Planning Base Case by resource type is represented below in Table 12-L.

Table 12-L: DEP and DEP Base Case and Joint Planning Case Comparison by Resource Type

DEC and DEP Combined Base Case Resources

Cumulative Winter Totals - 2019 - 2033

Nuclear	0
CC	5,352
CT	3,220
Total	8,572

DEC and DEP Joint Base Case Resources

Cumulative Winter Totals - 2019 - 2033

Nuclear	0
CC	5,352
CT	2,760
Total	8,112

13. SHORT-TERM ACTION PLAN

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

Continued Reliance on EE and DSM Resources:

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

- Continue to execute the Company's EE and DSM plan, which includes a diverse portfolio of EE and DSM programs spanning the residential, commercial, and industrial classes.

- Continue on-going collaborative work to develop and implement additional cost-effective EE and DSM products and services, such as: (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 the addition of significant renewable generation into its resource portfolio. Over the next five years, DEP is projecting to grow its renewable portfolio from 3,024 MW to 4,199 MW. Supporting policy such as SC Act 236, NC REPS, and NC HB 589 have all contributed to DEP's aggressive plans to grow its renewable resources. DEP is committed to meeting its targets for the SC DER Program, complying with NC REPS, and under HB 589, DEP and DEC are responsible for procuring renewable energy and capacity through a competitive procurement program. These activities will be done in a manner that allows the Companies to continue to reliably and cost-effectively serve customers' future energy needs. The Companies, under the competitive procurement program, are required to procure energy and capacity from renewable energy facilities in the aggregate amount of 2,660 MW through request for proposals. DEP and DEC plan to jointly implement the CPRE Program across the SC and NC service territories.

For further details, refer to Chapter 5.

Integration of Battery Storage:

The Company will begin investing in multiple grid connected storage systems dispersed throughout its North and South Carolina service territories that will be located on property owned by the Company or leased from its customers. These deployments will allow for a more complete evaluation of potential benefits to the distribution, transmission and generation system, while also providing actual operation and maintenance cost impacts of batteries deployed at a significant scale. Additionally, the Company continues to participate in an energy storage study to assess the economic potential for NC customers, mandated by HB 589. Results of the study are expected in December 2018.

Continue to Find Opportunities to Enhance Existing Clean Resources:

DEP is committed to continually looking for opportunities to improve and enhance its existing resources. DEP is expecting capacity uprates to its existing nuclear units, Brunswick and Harris, due to upcoming projects at those sites. The uprates total 56 MW from 2019 to 2028.

Addition of Clean Natural Gas Resources: [6]

- The Company continues to consider advanced technology combined cycle units as excellent options to meet future demand. The improving efficiency and reliability of CCs coupled with the continued trend of lower natural gas prices make this resource very attractive. As older units on the DEP system are retired, CC units continue to play an important role in the Company's future diverse portfolio.
    - A combined cycle unit (560 MW) is being constructed at the Asheville site and has an expected commercial operation date (COD) of November 2019.
    - Two Sutton LM6000 CT units (98 MW) were brought online in July of 2017.
    - One 22 MW block of Combined Heat and Power is considered in the 2018 IRP and included as a resource for meeting future generation needs. While no contracts have yet been signed for DEP, discussions with a potential steam host are currently underway. Future IRP processes will incorporate additional CHP as appropriate.

[6] Capacities represent winter ratings.

- Take actions to ensure the CC need in the winter of 2025 (expected COD in December 2024) is met. The 2016, 2017 and 2018 IRPs have indicated that this first need is best met with a combined cycle.

A summarization of the capacity resource changes for the Base Plans in the 2018 IRP is shown in Table 13-A below. Capacity retirements and resource additions are presented in the table 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 13-A DEP Short-Term Action Plan

Duke Energy Progress Short-Term Action Plan (1) (2)						
			Compliance Renewable Resources (Cumulative Nameplate MW)			
Year	Retirements	Additions (5)	Solar (3)	Biomass/Hydro	EE	DSM (4)
2019		30 MW Nuc Uprate 12 MW Energy Storage	2758	266	26	490
2020	384 MW Asheville 1-2	560 MW Asheville CC 6 MW Nuc Uprate 12 MW Energy Storage 30 MW Short-Term PPA	3061	266	44	501
2021	514 MW Darlington CT	4 MW Nuc Uprate 22 MW CHP 12 MW Energy Storage 590 MW Short-Term PPA	3341	120	62	511
2022		6 MW Nuc Uprate 14 MW Energy Storage 590 MW Short-Term PPA	3588	115	79	521
2023		14 MW Energy Storage 430 MW Short-Term PPA	3760	103	104	530

Notes:

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

(2) Dates represent when the project impacts the winter peak.

(3) Capacity is shown in nameplate ratings.

(4) Includes impacts of grid modernization.

(5) Energy Storage capacity represents 80% of nameplate.

Continue with Plan for Subsequent License Renewal of Existing Nuclear Units:

As discussed in Chapter 10, Duke Energy will continue to evaluate SLR for all its nuclear plants and is actively working on DEC's Oconee Nuclear Station SLR application to extend the licenses to 80 years. The remaining nuclear sites will do likewise where the cost/benefit balance proves acceptable.

Continued Development and Implementation of Capacity Value of Solar:

Conventional thermal resources are typically counted as 100% of net capability in reserve margin calculations for future generation planning since these resources are fully dispatchable resources when not on forced outage or planned maintenance. Due to the diurnal pattern and intermittent nature of solar energy resources, it is not reasonable to assume that these resources provide the same capacity credit as a fully dispatchable resource. An outside consultant calculated the capacity value of incremental solar additions for DEP and DEC for use in the resource planning process.

Continued Transition Toward Integrated Systems and Operations Planning:

As explained in Chapter 6, the traditional methods of utility resource planning are continuing to evolve. DEP is committed to moving toward an integrated planning process to meet the changing needs of planning in the future. The traditional methods of utility resource planning must be enhanced to address shifting trends through an Integrated System and Operations Planning (ISOP) effort.

In the 2018 IRP, DEP has begun to adapt its IRP to adjust to this changed world, recognizing that this process will continue to evolve. One key goal of ISOP is for the planning models to reasonably mimic the future operational realities to allow DEP to serve its customers with newer technologies. These enhancements in planning are expected to be addressed over the next several years, as soon as the modeling tools, processes and data development will allow.

Continued Focus on Environmental Compliance:

- Retire older coal generation.
    - As of December 2013, all of DEP's older, un-scrubbed coal units have been retired.
    - DEP has retired approximately 1,700 MW of older coal units in total since 2011.
    - Asheville Units 1 and 2 (384 MW) are expected to retire in November of 2019.

- Retire older CT generation.
    - As of May 2018, DEP has retired approximately 520 MW of older CT generation. The most recent retirements include:
        1. Sutton Units 1, 2A and 2B (76 MW) were retired in March and July of 2017.
        2. Darlington Unit 9 (65 MW) was retired in June of 2017 and Darlington Unit 5 (66 MW) was retired in May of 2018.
    - The Company continues to evaluate the condition and economic viability of the older CTs, resulting in expected future retirements.
        1. Darlington Units 1-4, 6-8 and 10 (514 MW) are expected to retire by December 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).

Wholesale:

- Continue to pursue existing and potential opportunities for wholesale power sales agreements within the Duke Energy balancing authority area.
- Over the next five years, DEP has approximately 1,200 MW of purchased power contracts that expire under the current contract terms. The Company plans to engage the marketplace to determine the feasibility of extending existing contracts or replacing them with other purchased power arrangements to economically meet customer demand.

Regulatory:

- Continue to monitor energy-related statutory and regulatory activities.
- Continue to examine the benefits of joint capacity planning and pursue appropriate regulatory actions.

DEP Request for Proposal (RFP) Activity:

Duke Energy Progress Capacity and Energy Market Solicitation

DEP has identified a near term need for approximately 2,000 MW of firm dispatchable peaking/intermediate capacity and energy resources resulting from existing traditional purchase power contract expirations. To meet this need, DEP is seeking proposal extensions from existing purchase power contract suppliers and new capacity proposals from similar operationally capable existing generation facilities or systems with firm transmission deliverability into DEP. Successfully selected proposals are expected to be multi-year peaking/intermediate negotiated contracts with terms up to five years in duration beginning in year 2020 that meet industry standards for commercial availability and dispatchability requirements. The capacity and energy market solicitation was released on August 27, 2018 and closed on September 24, 2018. Analysis is underway with expectations of contract completion by the first quarter of 2019.

Duke Energy Carolinas/Progress Swine Waste Fueled RFP – North Carolina

DEP and DEC released a Request for Proposals soliciting proposals for swine waste fueled biogas, the supply of electric power fueled by swine waste, or swine RECs (renewable energy certificates). Swine biogas projects must be sited in the state of North Carolina, Renewable Energy Facility proposals must be from swine projects sited within the NC/SC Duke Energy retail/wholesale service territory, and North Carolina qualifying in-state and out-of-state REC-Only proposals (electric swine RECs). This RFP solicited up to 750,000 MMBtu (million British thermal units), or the equivalent in MWh (megawatt hours) which is approximately 110,000 MWh from project developers. RECs secured under this RFP will be used for compliance with the swine waste set aside under REPS. Proposal structure allowed for this RFP was for Renewable Natural Gas Contracts or Purchase Power Agreements with terms of up to 20 years. RFP released December 15, 2017 and closed on January 29, 2018. Seven responses were received to the RFP, proposals have been evaluated, and have executed contracts with two of the projects. In addition, DEP/DEC is working with three other bids from the RFP while the respondents further develop their projects before moving forward.

Competitive Procurement of Renewable Energy (CPRE)

Pursuant to N.C. Gen. Stat. § 62-110.8, DEP has initiated the first RFP solicitation under the Competitive Procurement of Renewable Energy Program. This initial RFP solicitation was released on July 10, 2018 and closed on October 9, 2018.

DUKE ENERGY PROGRESS

APPENDICES

APPENDICES:

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 Cases for the 2018 IRP. The selection of these plans considers takes into account the cost to customers, resource diversity, reliability and the long-term carbon intensity of the system.

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

A. Overview of Analytical Process

The analytical process consists of four steps:

1. Assess resource needs
2. Identify and screen resource options for further consideration
3. Develop portfolio configurations
4. Perform portfolio analysis 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.
- 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 resource needs to meet energy and peak demands in the future. The following assumptions impacted the 2018 resource plan:

- Peak Demand and Energy Growth - The growth in winter customer peak demand after the impact of energy efficiency averaged 0.6% from 2019 through 2033.[7] The forecasted compound annual growth rate for energy is 0.5% after the impacts of energy efficiency programs are included.
- Generation / Purchase Power
    - Undesignated short-term purchased power agreements (PPAs) totaling 2,070 MW from December 2019 through December 2023 aid in meeting reserve requirements over that time period. These PPAs were assumed to have 5-year contract lives, and therefore, the initial PPAs begin rolling off in December 2024.
    - Completion of the 560 MW Asheville CC in November 2019
    - Nuclear uprates totaling 52 MW between 2019 and 2024 at Brunswick and Harris Nuclear plants
- Retirements
    - Retirement of 384 MW of coal generation at Asheville Steam Station in November 2019
    - Retirement of 514 MW of CT generation (Units 1-4, 6-8, 10) at the Darlington Plant in December 2020
    - Retirement of 232 MW of CT generation at the Weatherspoon and Blewett Plants in December 2024
    - Retirement of 1,053 MW of coal generation at the Roxboro Steam Plant (Units 1&2) in December 2028
- Purchase Power Contract Expirations
    - Nearly 1,500 MW of purchase power contracts expire between January 2019 and January 2024
- Reserve Margin - A 17% minimum winter planning reserve margin for the planning horizon

[7] This growth rate does not match the growth provided in the load forecasting sections. This number includes a 150 MW firm sale through 2024.

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, renewable, and energy storage). Supply-side options were 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:

- Base load – 600 MW – Small Modular Reactor (SMR)
- Base load – 1,339 MW – 2x2x1 Advanced Combined Cycle (No Inlet Chiller and Fired)
- Base load – 22 MW – Combined Heat & Power (Combustion Turbine)
- Peaking/Intermediate – 460 MW – 2 x 7FA.05 CTs
    - (Based upon the cost to construct 4 units, available for brownfield sites only)
- Peaking/Intermediate – 919 MW 4 x 7FA.05 Combustion Turbines (CTs)
- Renewable – 50 MW Solar PV, Fixed-tilt (FT)
- Renewable – 50 MW Solar PV, Single Axis Tracking (SAT)
- Storage – Grid Tied 20 MW / 80 MWh Li-ion Battery

Energy Efficiency and Demand-Side Management:

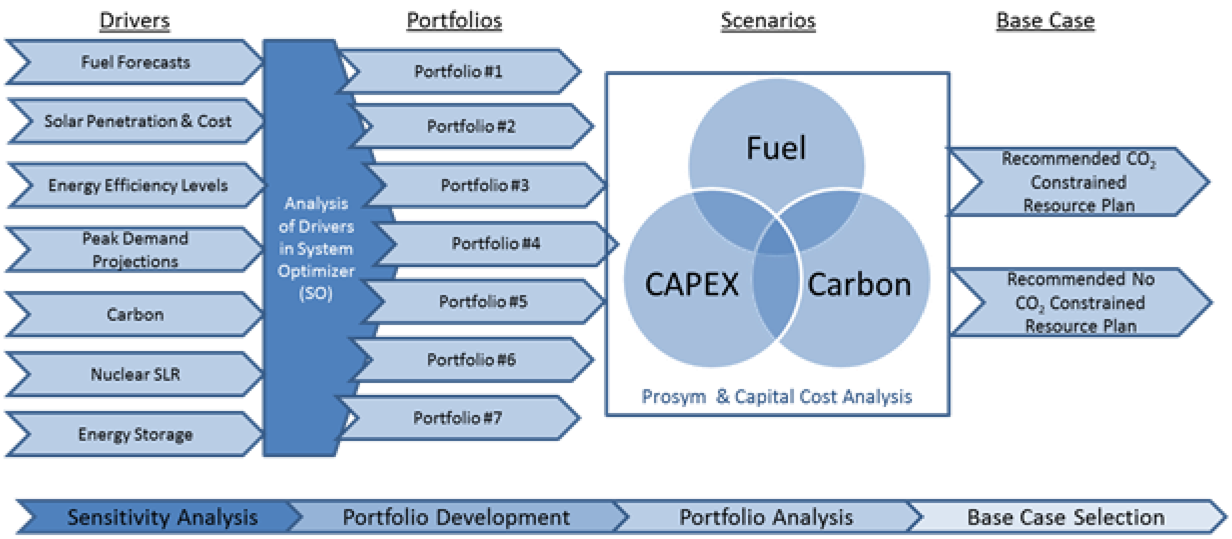
EE and DSM programs continue to be an important part of Duke Energy Progress' system mix. The Company considered both EE and DSM programs in the IRP analysis. As described in Appendix D, EE and DSM measures are compared to generation alternatives to identify cost-effective EE and DSM programs.

In the Base Case, the Company modeled the program costs associated with EE and DSM based on a combination of both internal company expectations and projections based on information from the 2016 market potential study. In the DEP and DEC Merger Settlement Agreement, the Company agreed to aspire to a more aggressive implementation of EE throughout the planning horizon. The impacts of this goal were incorporated in one of the portfolios evaluated. The program costs used for this analysis leveraged the Company's internal projections for the first five years and in the longer term, utilized the updated market potential study data incorporating the impacts of customer participation rates over the range of potential programs.

3. Develop Portfolio Configurations

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

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



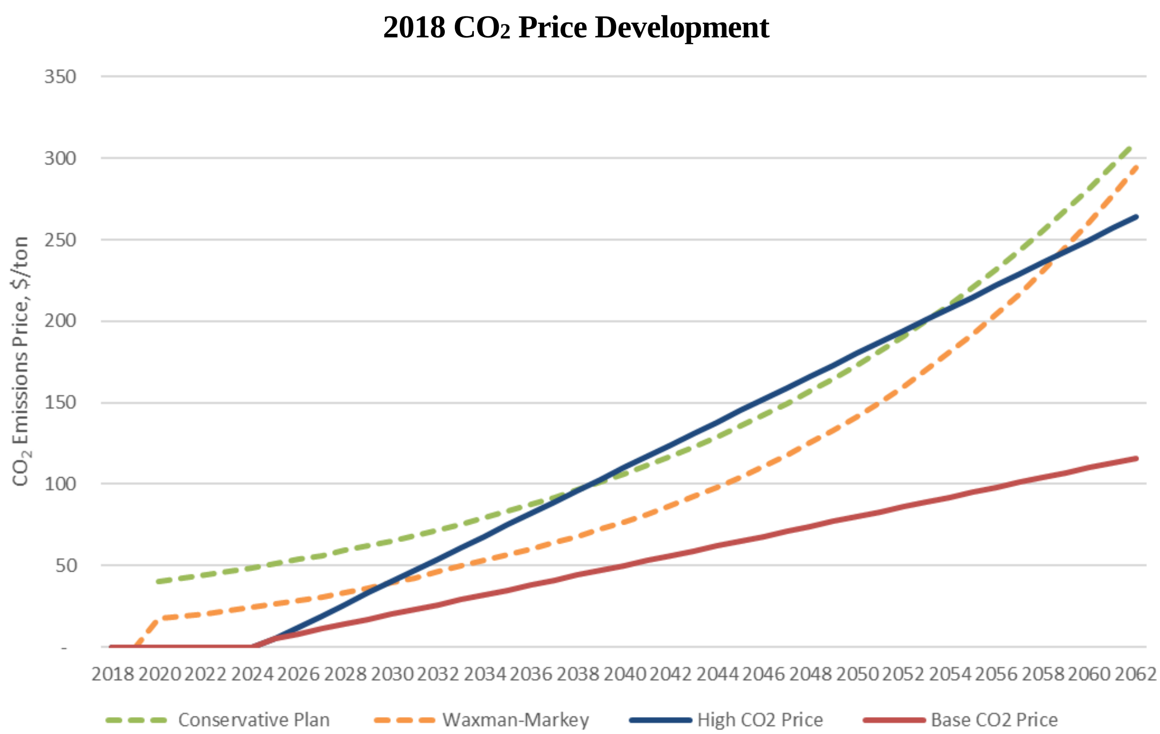
The Company conducted a sensitivity analysis of various drivers using the simulation modeling software, *System Optimizer* (SO). The expansion plans produced by SO were compared and seven portfolios that encompass the impact of the range of input sensitivities were identified. The seven portfolios were then analyzed in multiple scenarios in the hourly production cost model, PROSYM, to determine the optimum base case. An overview of the base planning assumptions and sensitivities considered in both SO and PROSYM are outlined below:

- Impact of potential carbon constraints
  - ➢ In the current legislative / regulatory environment, predicting future carbon constraints is becoming increasingly difficult. In October 2017, the EPA began the formal process to change EPA rules and repeal the previous administration's Clean Power Plan (CPP). With the CPP likely repealed in the next year to two years, the Company developed an internal CO_2 allowance price, or "Base CO_2 Price," which would lead to a 40% CO_2 reduction from a 2005 baseline by 2030, a 50% reduction by 2040, and a 60% reduction by 2050 for the Company's regulated utilities (Duke Energy Indiana (DEI), Duke Energy Kentucky (DEK), Duke Energy Florida (DEF), DEP, and DEC). The "Base CO_2 Price" falls between the expected CPP price on the low end, and the previously proposed Waxman/Markey legislation on the high end. Additionally, the Company

developed a "High CO_2 Price" that was based on the Waxman-Markey legislation and the recently proposed "Conservative Plan". The "High CO_2 Price" [8] would support a CO_2 reduction of 80% by 2050. Figure A-2 presents a view of the carbon prices used in the analysis, along with the Conservative Plan and Waxman-Markey legislation prices.

- Base CO_2 Price – Incorporated an intrastate CO_2 tax starting at $5/ton in 2025 and escalating at $3/ton annually that was applied to all carbon emissions.
- High CO_2 Price – Incorporated an intrastate CO_2 tax starting at $5/ton in 2025 and escalating at $7/ton annually that was applied to all carbon emissions.

Figure A-2: Comparison of CO_2 Prices and Other CO_2 Reference Prices



[8] https://www.clcouncil.org/media/TheConservativeCaseforCarbonDividends.pdf

- ***Retirements:***

  - Coal assets – For this IRP, the depreciation book life was used as a placeholder for future retirement dates for coal assets. Based on this assumption, 1,053 MW of coal generation were retired at the Roxboro Steam Plant (Units 1&2) in December 2028. Additionally, per the Mountain Energy Act (NC Senate Bill 716) 384 MW of coal generation at Asheville Steam Station are required to retire by January 31, 2020. However, for planning purposes, the Asheville Steam Station is assumed retired when the Asheville CC enters service in November 2019.

  - CT assets - For this IRP, the depreciation book life was used as a placeholder for future retirement dates for CT assets. Based on this assumption, 514 MW of CT generation (Units 1-4, 6-8, 10) at the Darlington Plant were retired in December 2020. Additionally, 164 MW of CT generation at the Weatherspoon Plant and 68 MW of CT generation at the Blewett Plant were assumed retired in December 2024.

- ***Nuclear assets:***

  - Robinson Nuclear Plant is the oldest DEP nuclear power reactor. Its current operating license has been extended to 60 years and expires in 2030. NextEra's Turkey Point Station and Exelon Corporation's Peach Bottom plant have each submitted a Subsequent License Renewal (SLR) application to the Nuclear Regulatory Commission (NRC). Additionally, Dominion Energy has announced its intention to pursue SLRs for its Surry and North Anna plants. The Company views all of its existing nuclear fleet as excellent candidates for license extensions based on current condition and expected operation expenditures regardless of future carbon constraints. Based on recent NRC guidance for SLR, the NextEra and Exelon Corporation application submittals, and the announcement from Dominion Energy, the Company's base case assumes SLR for all existing nuclear generation, including Robinson Nuclear Station, from 60 to 80 years for planning purposes in this year's IRP.

    - A sensitivity was performed assuming SLRs were not pursued for any of the Company's nuclear assets.

  - SMR technology was "screened out" in the Technology Screening phase of the analysis as discussed in Appendix F. However, given the severity of the "High

CO_2 Price" sensitivity, and the need for zero-emitting, load following resources (ZELFRs), additional nuclear generation in the form of SMRs was allowed to be selected.

- ***Coal and natural gas fuel prices:***

  - Short-term pricing:
    - Natural Gas based on market prices from 2018 through 2028 transitioning to 100% fundamental by 2033.

    - Coal based on market observations through 2022 transitioning to 100% fundamental by 2028.

  - Long-term pricing: Based on the Company's fundamental fuel price projections.

    - High Fuel Price Sensitivity – A high fuel price sensitivity was developed where the short-term, or market, natural gas price was increased based on statistical analysis that produced a +1 Standard Deviation (Std) from the base market price. The average cumulative probability of the +1 Std was 90% (i.e. in 90% of the cases, the average price will be lower than this scenario). The long-term pricing component was increased based on the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2018 report which provided a "Low Resource and Technology" curve.

    - Low Fuel Price Sensitivity - A low fuel price sensitivity was developed where the short-term, or market, natural gas price was decreased based on statistical analysis that produced a -1 Std from the base market price. The average cumulative probability of the -1 Std was 6.7% (i.e. in 6.7% of the cases, the average price will be lower than this scenario). The long-term pricing component was increased based on the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2018 report which provided a "High Resource and Technology" curve.

- ***Capital Cost Sensitivities:***

  - As discussed in Appendix F, most technologies include specific Technology Forecast Factors which were sourced from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2017 which provides costs projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS) utilized by the EIA for the AEO. More nascent technologies, such as battery storage and, to a lesser extent, PV solar, have relatively steep projected cost declines over time compared to more established technologies such as CCs and CTs. The capital cost sensitivities conducted were as follows:

    - Low Capital Cost – Technology forecast factors were doubled thereby increasing the cost declines of all technologies over time.

    - High Capital Cost – Technology forecast factors were reduced by half, thereby decreasing the rate of cost decline of all technologies over time.

  - Solar – The base case includes renewable capacity components of the Transition MW of HB 589 such as capacity required for compliance with the SC DER Program, NC REPS, PURPA renewable purchases, legacy Green Source Rider program, and the additional three components of HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). The base case also includes additional projected solar growth beyond HB 589. Below is an overview of the solar base planning assumptions and the sensitivities performed:

    - Base – Solar facility costs continue to decrease over the next decade with a 30% Federal Investment Tax Credit (ITC) through 2019, 26% ITC in 2020, 22% ITC in 2021 and 10% ITC thereafter. Additional solar beyond compliance was allowed to be selected if economical.

    - 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 were reduced by 10%.

    - Higher Solar Penetration – Given the significant volume uncertainty around solar penetration, a high solar penetration scenario was performed to account for a number of potential factors that could increase solar additions over the planning horizon. These factors include events such as high carbon prices, lower solar capital costs, economical solar plus storage, continuation of renewable subsidies, and/or stronger renewable energy mandates.

- EE and Renewables – Two different options were evaluated with regards to the amount of EE and Renewables.

  - Base EE and Base Renewables

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

    - Base renewables correspond to the resources needed to meet components of the Transition MW of HB 589 such as capacity required for compliance with the SC DER Program, NC REPS, PURPA renewable purchases, legacy Green Source Rider program, and the additional three components of HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). Base renewables also includes additional projected solar growth beyond HB 589.

  - High EE and High Renewables

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

    - High EE – Established as part of the Progress Energy-Duke Energy Carolinas Merger Settlement Agreement. The cumulative EE achievements since 2009 are counted toward the cumulative settlement agreement impacts. By 2033, the high EE case accounts for an additional 124 MW of winter peak demand reduction versus the base EE case.

    - High Renewables –Added 310 MW of additional solar to the base NC and SC renewable planning assumptions by 2033 versus the base renewable case.

  - While not explicitly evaluated, the impacts of a Low EE future on the expansion, are similar to the impacts of the "high load" sensitivity that was evaluated in SO and that is discussed later in this section.

- ***Energy Storage:***

  - 140 MW of 4-hour Lithium ion batteries are included in the base case as placeholders for future assets to provide operational experience on the DEP system. These placeholders represent a limited amount of grid connected battery storage projects that have the potential to provide solutions for the transmission and distribution systems with the possibility of simultaneously providing benefits to the generation portfolio. As discussed in various sections throughout this document, the extent to which 4-hour battery storage can provide generation deferral benefits is still being evaluated, particularly when a single battery storage installment is expected provide multiple services in addition to generation and energy benefits. Additionally, the benefits of battery storage are most realized when the asset is grid-tied and the Company has real-time control of when the battery storage is dispatched to, or charged from, the system.

  The deployment of utility scale battery storage over the next decade will provide valuable real-world experience for optimizing and assessing the benefits of battery storage. Given the uncertainties in future battery deployments and the ability to fully contribute to generation deferral, the Base Case assumes that the 140 MW of placeholder battery storage provides 112 MW (or 80% of nameplate capacity)[9] towards meeting winter peak demand. These assumptions are likely to change as the Company gains experience operating utility-scale battery storage technologies. An additional battery storage sensitivity was also considered:

    - A battery storage sensitivity was also included in which a 575 MW 4-hour Lithium ion battery replaced a 460 MW CT block in a high renewable future.

- High and Low Load – The annual average load growth rate before impacts of EE from 2020 through 2033 was increased from 0.8% to 1.5% in the high load sensitivity and the annual average growth rate was reduced from 0.8% to 0.2% in the low load sensitivity.

[9] EPRI's "Technical Update: Evaluating the Capacity Value of Energy Storage (E. Lannoye & E. Ela, December 2017)" provides several methodologies for calculating capacity value of Energy Storage. The results range from ~40% to 100% of nameplate capacity as potential capacity value. For the purposes of the 2018 IRP, 80% was selected for planning purposes.

- 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.

Sensitivity Analysis Results:

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

Initial Resource Needs – The first resource need after executing on the 2,070 MW of undesignated short-term power purchases, occurs in December of 2024 in all cases. The high EE and low load sensitivities would have the impact of reducing the undesignated short-term power purchase requirements, but the first need for new generation would still occur in December 2024. The type of resource selected is consistently a CC regardless of fuel and carbon assumptions.

- Joint Planning Case - The first three resource needs are CCs, two in DEP, in 2024/2025 and 2026/2027, and one in DEC in 2027/2028. When joint capacity planning, the DEP CCs are not delayed, but the DEC CC is delayed one year to 2028/2029.

Renewable Generation – The timing of incremental solar beyond the capacity included in the base case was dependent on the CO_2 and fuel price assumptions as shown in Table A-1 below. It must be noted that incremental solar additions in DEP are only credited with a maximum of 1% contribution to winter peak capacity, and therefore, these incremental solar additions are only providing energy value and essentially no capacity value.

Table A-1: First Year of Incremental Solar Additions in DEP

	No CO_2	Base CO_2	High CO_2
Low Fuel	Not Selected	2052	2035
Base Fuel	Not Selected	2038	2031
High Fuel	2034	2030	2028

Additionally, in the case where solar prices were reduced by 10%, the first year of incremental solar additions accelerated from 2038 to 2035 in the Base CO_2 / Base Fuel case.

New Nuclear Selection – New nuclear additions, in the form of SMRs, were selected in the SO analysis in all High CO_2 cases, as well as, in the Base CO_2 / High Fuel case. As shown in Table A-2 below, the timing of new nuclear selection in the High CO_2 cases is dependent on the fuel price assumptions.

Table A-2: First Year of New Nuclear Additions

	No CO_2	Base CO_2	High CO_2
Low Fuel	Not Selected	Not Selected	2051
Base Fuel	Not Selected	Not Selected	2040
High Fuel	Not Selected	2040	2033

In the No SLR scenario for existing nuclear units, the timing for new nuclear generation accelerated from 2040 to 2036 in the High CO_2 / Base Fuel case. As continues to be the case, in order to meet potentially stringent CO_2 emission regulations, new nuclear generation will likely be needed. The timing of new nuclear generation is highly dependent on fuel price projections, as well as, subsequent license renewal of the existing nuclear generation fleet.

High EE and High Renewables – Within the 15-year planning horizon, the impact from High EE, in combination with High Renewables, was to delay the need for CT generation in 2029 and 2032 by one year each due to the reduction in winter peak demand net of EE impacts.

Gas Firing Technology Options – The number of CCs selected over the planning horizon varied with the fuel and CO_2 assumptions as shown in Table A-3 below, but in all cases, other than the CT Centric portfolio, the first two generation needs in 2025 and 2027 are met by CC technology.

Table A-3: Number of CCs Selected in 15-Year Planning Horizon

	No CO_2	Base CO_2	High CO_2
Low Fuel	2	2	2
Base Fuel	2	2	3
High Fuel	2	3	3

Portfolio Development:

Using insights gleaned from the sensitivity analysis, seven portfolios were developed. These portfolios were developed to assess the relative value of various generating technologies including CCs, CTs, Renewables, and Nuclear, as well as, energy storage under multiple scenarios. A description of the seven portfolios follows:

Portfolio 1 (Base CO_2 Future)

This portfolio represents a balanced generation portfolio with CCs and CTs making up the generation mix with incremental solar additions just beyond the 15-year window. While CCs are the preferred initial generating options in both DEP and DEC, CTs make up the vast majority of additional resources at the end of the 15-year planning horizon. This portfolio also includes base EE and renewable assumptions, along with 1,000 MW of economically selected solar just beyond the planning horizon. Additionally, 140 MW of nameplate battery storage placeholders are included. These placeholders represent a limited amount of grid connected battery storage projects that have the potential to provide solutions for the transmission and distribution systems with the possibility of simultaneously providing benefits to the generation resource portfolio.

Portfolio 2 (Base No CO_2 Future)

Within the 15-year planning horizon, this portfolio is the same as Portfolio 1. Beyond the planning window, CT technology generally takes precedence over CC technology. No additional solar was selected in this portfolio. The Base No CO_2 portfolio also includes base EE and renewable assumptions, along with 140 MW of nameplate battery storage placeholders.

Portfolio 3 (CT Centric)

This portfolio is similar to Portfolio 2. However, the 2027 CC need is replaced with CT technology to increase the concentration of CTs in this portfolio. Like Portfolio 2, this portfolio includes base EE and renewable assumptions, and no additionally selected solar. The portfolio includes 140 MW of nameplate storage placeholders.

Portfolio 4 (CC Centric – No Nuclear Future)

This portfolio represents a future where all existing nuclear assets are retired at the end of their current extended license period, and those nuclear assets are primarily replaced with CCs rather than new nuclear generation. The CC Centric Portfolio converts the entire 2029 CT block to CC technology. This portfolio also includes base EE and renewable assumptions, along with 1,000 MW of economically selected solar just beyond the planning horizon. Additionally, 140 MW of nameplate battery storage placeholders are included.

Portfolio 5 (High EE / High Renewables)

This portfolio includes the High EE and High Renewable assumptions in DEP. Solar nameplate capacity increases at a more rapid pace, and the total MW of solar is 310 MW greater in the High Renewable case by 2033. This portfolio includes an additional 124 MW of EE by the end of the planning horizon. Finally, this case also includes 140 MW of nameplate battery storage placeholders.

Portfolio 6 (CT Centric / High Renewables)

Like Portfolio 3, Portfolio 6 includes a high concentration of CT generation in the 15-year planning horizon. However, this portfolio includes the High Renewable assumption which accelerates solar additions in DEP while increasing the total amount of solar by approximately 300 MW. Portfolio 6 includes Base EE assumptions along with 140 MW of nameplate battery storage. This portfolio is especially illustrative when evaluating additional energy storage added in Portfolio 7.

Portfolio 7 (CT Centric with Battery Storage and High Renewables)

This portfolio converts the first 460 MW block of CTs in Portfolio 6 to 575 MW (nameplate) of 4-hour Lithium-ion battery storage in 2029. The additional 575 MW of battery storage is assumed to only provide generation and energy transfer capability that is 100% controlled by the Company. As such, the battery storage installation is assumed to provide 460 MW of winter peak capacity. The total amount of nameplate battery storage in DEP in this case is 715 MW by 2029.

An overview of the resource needs of each portfolio are shown in Table A-4 below.

Table A-4: Portfolio Summary for Duke Energy Progress[1,2]

	Portfolio 1 (Base CO_2 Future)	**Portfolio 2 (No CO_2 Future)**	**Portfolio 3 (CT Centric)**	**Portfolio 4 (CC Centric)**	**Portfolio 5 (High EE / High Renewables)**	**Portfolio 6 (CT Centric / High Renewables)**	**Portfolio 7 (CT Centric / High Renewables w/ Battery Storage)**
2024	Total Solar = 4061 Total Storage = 101 EE = 120	Total Solar = 4061 Total Storage = 101 EE = 120	Total Solar = 4061 Total Storage = 101 EE = 120	Total Solar = 4061 Total Storage = 101 EE = 120	Total Solar = 4187 Total Storage = 101 EE = 191	Total Solar = 4187 Total Storage = 101 EE = 120	Total Solar = 4187 Total Storage = 101 EE = 120
2025	CC = 1338 Total Solar = 4161 Total Storage = 121 EE = 138	CC = 1338 Total Solar = 4161 Total Storage = 121 EE = 138	CC = 1338 Total Solar = 4161 Total Storage = 121 EE = 138	CC = 1338 Total Solar = 4161 Total Storage = 121 EE = 138	CC = 1338 Total Solar = 4337 Total Storage = 121 EE = 220	CC = 1338 Total Solar = 4337 Total Storage = 121 EE = 138	CC = 1338 Total Solar = 4337 Total Storage = 121 EE = 138
2026	Total Solar = 4215 Total Storage = 141 EE = 155	Total Solar = 4215 Total Storage = 141 EE = 155	Total Solar = 4215 Total Storage = 141 EE = 155	Total Solar = 4215 Total Storage = 141 EE = 155	Total Solar = 4412 Total Storage = 141 EE = 246	Total Solar = 4412 Total Storage = 141 EE = 155	Total Solar = 4412 Total Storage = 141 EE = 155
2027	CC = 1338 Total Solar = 4269 Total Storage = 141 EE = 173	CC = 1338 Total Solar = 4269 Total Storage = 141 EE = 173	CT = 1380 Total Solar = 4269 Total Storage = 141 EE = 173	CC = 1338 Total Solar = 4269 Total Storage = 141 EE = 173	CC = 1338 Total Solar = 4487 Total Storage = 141 EE = 269	CT = 1380 Total Solar = 4487 Total Storage = 141 EE = 173	CT = 1380 Total Solar = 4487 Total Storage = 141 EE = 173
2028	Total Solar = 4323 Total Storage = 141 EE = 187	Total Solar = 4323 Total Storage = 141 EE = 187	Total Solar = 4323 Total Storage = 141 EE = 187	Total Solar = 4323 Total Storage = 141 EE = 187	Total Solar = 4562 Total Storage = 141 EE = 288	Total Solar = 4562 Total Storage = 141 EE = 187	Total Solar = 4562 Total Storage = 141 EE = 187
2029	CT = 1840 Total Solar = 4377 Total Storage = 141 EE = 200	CT = 1840 Total Solar = 4377 Total Storage = 141 EE = 200	CT = 1840 Total Solar = 4377 Total Storage = 141 EE = 200	CC = 1338 CT = 460 Total Solar = 4377 Total Storage = 141 EE = 200	CT = 1380 Total Solar = 4637 Total Storage = 141 EE = 307	CT = 1840 Total Solar = 4637 Total Storage = 141 EE = 200	CT = 1380 Total Solar = 4637 Total Storage = 716 EE = 200
2030	Total Solar = 4431 Total Storage = 141 EE = 211	Total Solar = 4431 Total Storage = 141 EE = 211	Total Solar = 4431 Total Storage = 141 EE = 211	Total Solar = 4431 Total Storage = 141 EE = 211	CT = 460 Total Solar = 4712 Total Storage = 141 EE = 323	Total Solar = 4712 Total Storage = 141 EE = 211	Total Solar = 4712 Total Storage = 716 EE = 211
2031	Total Solar = 4456 Total Storage = 141 EE = 221	Total Solar = 4456 Total Storage = 141 EE = 221	Total Solar = 4456 Total Storage = 141 EE = 221	CT = 920 Total Solar = 4456 Total Storage = 141 EE = 221	Total Solar = 4747 Total Storage = 141 EE = 336	Total Solar = 4747 Total Storage = 141 EE = 221	Total Solar = 4747 Total Storage = 716 EE = 221
2032	CT = 460 Total Solar = 4481 Total Storage = 141 EE = 229	CT = 460 Total Solar = 4481 Total Storage = 141 EE = 229	CT = 460 Total Solar = 4481 Total Storage = 141 EE = 229	CT = 460 Total Solar = 4481 Total Storage = 141 EE = 229	Total Solar = 4782 Total Storage = 141 EE = 349	CT = 460 Total Solar = 4782 Total Storage = 141 EE = 229	CT = 460 Total Solar = 4782 Total Storage = 716 EE = 229
2033	CT = 460 Total Solar = 4506 Total Storage = 141 EE = 236	CT = 460 Total Solar = 4506 Total Storage = 141 EE = 236	CT = 460 Total Solar = 4506 Total Storage = 141 EE = 236	CT = 460 Total Solar = 4506 Total Storage = 141 EE = 236	CT = 920 Total Solar = 4817 Total Storage = 141 EE = 360	CT = 460 Total Solar = 4817 Total Storage = 141 EE = 236	CT = 460 Total Solar = 4817 Total Storage = 716 EE = 236
Total	CC = 2676 CT = 2760 Total Solar = 4506 Total Storage = 141 EE = 236	CC = 2676 CT = 2760 Total Solar = 4506 Total Storage = 141 EE = 236	CC = 1338 CT = 4140 Total Solar = 4506 Total Storage = 141 EE = 236	CC = 4014 CT = 2300 Total Solar = 4506 Total Storage = 141 EE = 236	CC = 2676 CT = 2760 Total Solar = 4817 Total Storage = 141 EE = 360	CC = 1338 CT = 4140 Total Solar = 4817 Total Storage = 141 EE = 236	CC = 1338 CT = 3680 Total Solar = 4817 Total Storage = 716 EE = 236

[1] EE represents the cumulative new energy efficiency additions each year. [2]Solar does not include 0.5% annual degradation.

4. Perform Portfolio Analysis

Each of the seven portfolios identified in the screening analysis were evaluated in more detail with an hourly production cost model (PROSYM) under future fuel price and CO_2 scenarios to determine the robustness of each portfolio under varying fuel and carbon futures. The run matrix for the nine scenarios is summarized in Table A-5 below.

Table A-5: PROSYM Run Matrix for Portfolio Analysis

	No CO_2	Base CO_2	High CO_2
Low Fuel			
Base Fuel			
High Fuel			

The PROSYM model provided the system production costs for each portfolio under the scenarios shown above. The model included DEP's non-firm energy purchases and sales associated with the Joint Dispatch Agreement (JDA) with DEC, and as such, the model optimized both DEP and DEC and provided total system (DEP + DEC) production costs. The PROSYM results were separated to reflect system production costs that were solely attributed to DEP to account for the impacts of the JDA. The DEP specific system production costs were then added to the DEP specific capital costs for each portfolio to develop the total Present Value of Revenue Requirements (PVRR) for each portfolio under the given fuel price and CO_2 conditions.

The seven portfolios were ranked in each of the nine fuel and carbon scenarios, and the portfolio with the lowest PVRR in each of the nine scenarios was identified.

Additionally, high and low capital cost sensitivities were conducted to determine if varying future price projections for each technology would impact the results of the scenario analysis.

PVRR Results:

Table A-6 below reflects the portfolio that performed best (i.e. lowest PVRR) under each scenario, as well as, the delta PVRR to the next lowest portfolio (Port).

Table A-6: Lowest PVRR (thru 2068) Portfolios Under Each Scenario (2018 dollars in Millions)

PVRR thru 2068 (2018 $M)	No CO_2	Base CO_2	High CO_2
Low Fuel	Portfolio 2 (-$132 M vs Port 3)	Portfolio 1 (-$84 M vs Port 2)	Portfolio 1 (-$409 M vs Port 2)
Base Fuel	Portfolio 2 (-$17 M vs Port 1)	Portfolio 1 (-$231 M vs Port 2)	Portfolio 1 (-$536 M vs Port 2)
High Fuel	Portfolio 1 (-$257 M vs Port 2)	Portfolio 1 (-$493 M vs Port 2)	Portfolio 1 (-$533 M vs Port 5)

The following table summarizes the total PVRR for each portfolio in the scenarios above versus Portfolio 1.

Table A-7: Total PVRR (thru 2068) Comparison of All Portfolios vs Portfolio 1 (2018 dollars in Millions)

	Portfolio 2 (Base No CO_2 Future)	Portfolio 3 (CT Centric)	Portfolio 4 (CC Centric)	Portfolio 5 (High EE / High Renew)	Portfolio 6 (CT Centric / High Renew)	Portfolio 7 (CT Centric / High Renew w/ Batt Storage)
Base Fuel / Base CO_2	$231	$798	$8,116	$565	$1,119	$702
Base Fuel / High CO_2	$536	$1,486	$10,839	$560	$1,682	$1,060
Base Fuel / No CO_2	($17)	$264	$5,784	$583	$667	$483
High Fuel / BaseCO_2	$493	$1,226	$10,871	$532	$1,427	$847
High Fuel / High CO_2	$759	$1,885	$13,602	$533	$1,977	$1,143
High Fuel / No CO_2	$257	$667	$8,586	$553	$979	$606
Low Fuel / Base CO_2	$84	$503	$6,515	$598	$876	$656
Low Fuel / High CO_2	$409	$1,177	$9,301	$574	$1,430	$984
Low Fuel / No CO_2	($183)	($51)	$4,182	$595	$447	$384

In addition to the sensitivities conducted above, capital cost sensitivities were also conducted. In the low capital cost sensitivity, technology specific forecast factors were decreased (i.e. greater cost declines in technology costs over time). In the high capital cost sensitivity, technology specific forecast factors were increased (i.e. lower cost declines in technology costs over time). One example of the impact of these cost sensitivities, is the impact on project costs of 4-hour Lithium ion battery storage. In the base case, battery storage costs are projected to drop by nearly 40% by 2025 in real terms. In the low and high capital cost sensitivities, battery storage costs are projected to drop by slightly over 60% and slightly over 20% respectively, by 2025. The results on the lowest PVRR portfolios due to these capital costs sensitivities are shown in Tables A-8 and A-9.

Table A-8: Lowest PVRR (thru 2068) Portfolios Under Each Scenario – Low Capital Cost Sensitivity (2018 dollars in Millions)

PVRR thru 2068 (2018 $M)	No CO_2	Base CO_2	High CO_2
Low Fuel	Portfolio 2 (-$6 M vs Port 1)	Portfolio 1 (-$260 M vs Port 2)	Portfolio 1 (-$586 M vs Port 5)
Base Fuel	Portfolio 1 (-$60 M vs Port 2)	Portfolio 1 (-$408 M vs Port 2)	Portfolio 1 (-$579 M vs Port 5)
High Fuel	Portfolio 1 (-$351 M vs Port 7)	Portfolio 1 (-$551 M vs Port 5)	Portfolio 1 (-$552 M vs Port 5)

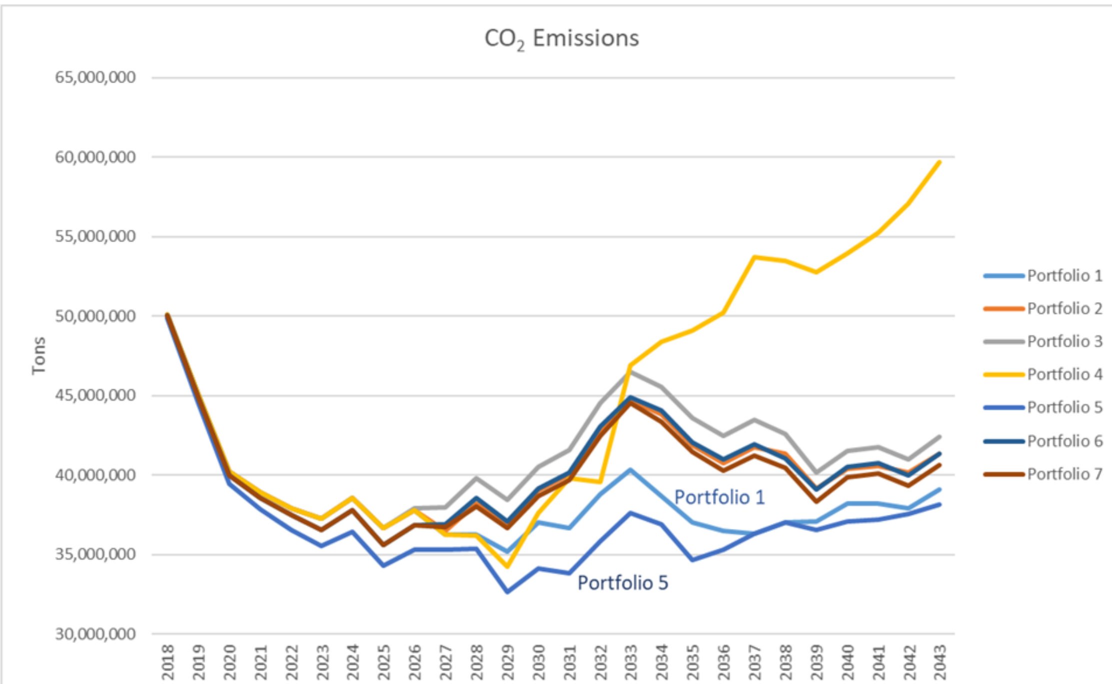
Table A-9: Lowest PVRR (thru 2068) Portfolios Under Each Scenario – High Capital Cost Sensitivity (2018 dollars in Millions)

PVRR thru 2068 (2018 $M)	No CO_2	Base CO_2	High CO_2
Low Fuel	Portfolio 2 (-$137 M vs Port 3)	Portfolio 2 (-$44 M vs Port 2)	Portfolio 1 (-$282 M vs Port 2)
Base Fuel	Portfolio 2 (-$144 M vs Port 1)	Portfolio 1 (-$104 M vs Port 2)	Portfolio 1 (-$409 M vs Port 2)
High Fuel	Portfolio 1 (-$129 M vs Port 2)	Portfolio 1 (-$366 M vs Port 2)	Portfolio 1 (-$448 M vs Port 5)

CO_2 Emissions:

Over the next 15 years, and beyond, Portfolio 1 provides significant CO_2 emission reductions as shown in Figure A-3 below. Only Portfolio 5 (High EE / High Renewables) provides similar or increased carbon reductions over the life of the plan. Additionally, if existing nuclear generation was not extended in DEP, or was not replaced with new nuclear generation, CO_2 emissions would rise significantly as each nuclear plant was retired as shown in Portfolio 4 (Yellow).

Figure A-3: DEP + DEC Carbon Emissions Summary – All Portfolios



Conclusions:

Base CO_2 Portfolio Selection:

For planning purposes, Duke Energy considers both a carbon constrained future and a non-carbon constrained future in the development of the base case portfolios. As the base planning assumption. If a carbon constrained future is either delayed or is more restrictive than the base plan, or other variables such as fuel price and capital costs change significantly from the base assumptions, the selected carbon constrained portfolio should be adequately robust to still provide value in those futures. Another factor that is considered when selecting the base portfolio is the likelihood that the selected portfolio can be executed as shown. Under those considerations, the Company selected Portfolio 1 (Base CO_2 Future) as the base portfolio for planning assumptions.

Portfolio 1 includes a diverse compilation of resources including CCs, CTs, battery storage, and increasing amounts of EE/DSM and solar resources in conjunction with existing nuclear, natural gas, renewables and other assets already on the DEP system. This portfolio also enables the Company to lower carbon emissions under a range of future scenarios at a lower cost than most other scenarios.

Finally, the Carbon Constrained Base Case was developed utilizing consistent assumptions and analytic methods between DEP and DEC, where appropriate. This case does not consider 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 explores the potential for DEP and DEC to share firm capacity was also developed.

No CO_2 Portfolio Selection:

While Duke Energy presents a base resource plan that was developed under a carbon constrained future, the Company also provides a No Carbon Base Case expansion plan that reflects a future without CO_2 constraints. In DEP, this expansion plan is represented by Portfolio 2 (Base No CO_2 Future). There is no difference between the Carbon Constrained Base Case and the No Carbon Base Case over the 15-year planning horizon. However, beyond the 15-year window, CT technology generally takes precedence over CC technology. Because of the trend towards CT technology and the absence of incremental solar in the years just after the planning window, Portfolio 2 has a lower capital cost and a slightly lower PVRR than Portfolio 1 in the Base Fuel / No CO_2 scenario.

Other Findings:

Based on the analysis discussed above, other observations regarding the future of nuclear, solar and battery storage assets on the system can be made.

- **Existing nuclear assets**
  - Portfolio 4 (CC Centric) represents a future where licenses for existing nuclear assets are allowed to expire and those nuclear assets are mainly replaced with CC technology. This portfolio increases capital costs versus the base portfolio as nuclear assets are retired and replaced with CCs, and, the system production cost penalty of replacing nuclear assets that provide nearly 50% of the Company's energy at almost zero fuel cost and zero CO_2 emissions, with CC technology is severe. While retiring existing nuclear assets may provide more value if new nuclear technology such as SMRs become more established at lower costs, current projections show that maintaining the option to continue operating the Company's existing nuclear fleet provides value for the Company and its customers.
- **Renewables**
  - The level of solar generation in DEP is significant and increasing. Increasing solar generation on the DEP system is likely to cause additional operational issues and costs as more conventional generating assets are required to provide additional ancillary services to manage the intermittency of solar generation. The addition of incremental solar and EE in Portfolio 5 caused a PVRR increase of at least $500M in all cases. Even in a CT Centric future, where there is a greater concentration of energy limited resources, the addition of solar led to an increase in PVRR in all scenarios.
- **Battery Storage**
  - Portfolio 7 (CT Centric / High Renewables / Battery Storage) was developed off Portfolio 6 (CT Centric / High Renewables). In Portfolio 7, a 460 MW block of CT generation in the winter of 2028/2029 was converted to 575 MW of battery storage. While the total cost of Portfolio 7 was significantly higher than Portfolio 1, the addition of battery storage improved the PVRR versus Portfolio 6 by as much as $800M in a high fuel / high CO_2 scenario. While this case shows potential cost savings associated with battery storage, it is important to consider several factors including:

- Based on the provided cost curves, battery storage costs are projected to decline 50% by 2028.

- The value shown in this scenario is for incremental battery storage added to a portfolio that already includes 140 MW of 4-hour battery storage in DEP. As with all assets, whether CCs, CTs, solar, or nuclear, there is a point of diminishing returns as more storage is added to the system. It is unclear from this analysis, where battery storage falls on that value curve. As a point of reference, a similar analysis was conducted in the DEC IRP, and in that case, adding battery storage to the system created a cost increase. At least two potential reasons for this difference are 1) DEC already includes 2,400 MW of storage in the form of pumped hydro storage, and 2) DEC has overall less MW of solar which could be limiting the benefits of additional storage in DEC.

- The battery storage in this case is a grid tied asset that can be charged with system energy. It is likely that the battery's value would diminish if it were only allowed to charge with solar energy. In that case, the battery would lose the value of being charged with off-peak energy that is generated when solar is not available.

- The model assumes the Company has real-time control of the battery to maximize the battery's value. Without real-time control, the value of the battery on the DEP system is limited.

- While these results suggest that battery storage may have value as a generation deferral and energy arbitrage asset, it is possible that the value of battery storage may be even greater under other applications such as distribution or transmission asset deferral. Additionally, and as discussed elsewhere in this document, the value of battery storage for generation deferral, energy arbitrage, and/or ancillary services may be diminished if the battery is also providing support for voltage control, distribution asset deferral, or emergency back-up power as part of other use cases.

To better understand the true value of battery storage in DEP, it is important for the Company to operate utility storage on its system to properly evaluate the abilities and value of battery storage.

Value of Joint Planning:

To demonstrate the value of sharing capacity with DEC, a Joint Planning Case was developed to examine the impact of joint capacity planning on the resource plans. The impacts were determined by comparing how the combined Base Cases of 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. Table A-10 shows the base expansion plans (Portfolio 1 for both DEP and DEC) through 2033, if separately planned, compared to the Joint Planning Case. The total of the two combined resource requirements is then compared to the amount of resources needed if DEP and DEC could jointly plan for capacity. Years where the Joint Planning Case differs from the individual Utility cases are highlighted.

Table A-10: Comparison of Carbon Constrained Base Case Portfolio to Joint Planning Case

	DEC Portfolio 1 (Base CO_2)	DEP Portfolio 1 (Base CO_2)	1 BA (Base CO_2)
2024	Total Solar = 2834 Total Storage = 100 EE = 248	Total Solar = 4061 Total Storage = 101 EE = 120	Total Solar = 6895 Total Storage = 201 EE = 368
2025	Total Solar = 2939 Total Storage = 125 EE = 284	CC = 1338 Total Solar = 4161 Total Storage = 121 EE = 138	CC = 1338 Total Solar = 7100 Total Storage = 246 EE = 422
2026	Total Solar = 3065 Total Storage = 150 EE = 318	Total Solar = 4215 Total Storage = 141 EE = 155	Total Solar = 7280 Total Storage = 291 EE = 473
2027	Total Solar = 3191 Total Storage = 150 EE = 350	CC = 1338 Total Solar = 4269 Total Storage = 141 EE = 173	CC = 1338 Total Solar = 7460 Total Storage = 291 EE = 522
2028	**CC = 1338** Total Solar = 3317 Total Storage = 150 EE = 370	Total Solar = 4323 Total Storage = 141 EE = 187	Total Solar = 7640 Total Storage = 291 EE = 557
2029	Total Solar = 3443 Total Storage = 150 EE = 383	**CT = 1840** Total Solar = 4377 Total Storage = 141 EE = 200	CC = 1338 CT = 1380 Total Solar = 7820 Total Storage = 291 EE = 583
2030	Total Solar = 3569 Total Storage = 150 EE = 390	Total Solar = 4431 Total Storage = 141 EE = 211	Total Solar = 8000 Total Storage = 291 EE = 601
2031	CC = 1338 Total Solar = 3594 Total Storage = 150 EE = 392	Total Solar = 4456 Total Storage = 141 EE = 221	CC = 1338 Total Solar = 8050 Total Storage = 291 EE = 613
2032	Total Solar = 3619 Total Storage = 150 EE = 394	**CT = 460** Total Solar = 4481 Total Storage = 141 EE = 229	Total Solar = 8100 Total Storage = 291 EE = 623
2033	CT = 460 Total Solar = 3644 Total Storage = 150 EE = 398	CT = 460 Total Solar = 4506 Total Storage = 141 EE = 236	CT = 1380 Total Solar = 8150 Total Storage = 291 EE = 634
Total	CC = 2676 CT = 460 Total Solar = 3644 Total Storage = 150 EE = 398	CC = 2676 CT = 2760 Total Solar = 4506 Total Storage = 141 EE = 236	CC = 5352 CT = 2760 Total Solar = 8150 Total Storage = 291 EE = 634

A comparison of the DEP and DEC Combined Base Case resource requirements to the Joint Planning Scenario requirements illustrates the ability to defer a CC and CT resource in the late 2020s. 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 20.3% and 19.5%, respectively, from the first resource need in 2020 through 2033. The lower reserve margin in the Joint Planning Case indicates that DEC and DEP more efficiently and economically meet capacity needs when planning for capacity jointly. This is reflected in a capital PVRR savings of $250 million for the Joint Planning Case as compared to the Combined Base Case. Though not included in the Joint Planning Case analysis, the ability to share capacity between DEP and DEC would also limit the amount of undesignated short-term market purchases identified in the 2020 to 2024 timeframe in DEP.

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. Following procurement of the undesignated short-term market purchases in 2020 through the winter of 2023/2024, the first undesignated resource need is in December of 2024 to meet the minimum reserve margin requirement in the winter of 2024/2025. The results of this analysis show that this need is best met with CC generation.

2. The ability to jointly plan capacity with DEC provides customer savings by allowing for the deferral of new generation resources over the 15-year planning horizon.

3. Nuclear generation, whether relicensing or new build, is essential for continuing to lower CO_2 emissions on the system.

Battery storage may provide value in DEP as intermittent energy resources increase on the system. However, since the value is highly dependent on continued steep cost declines of the technology, and the specific use case of the battery, it is prudent to continue monitoring battery storage costs while testing their capabilities on the DEP system.

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.

The tables below list the Duke Energy Progress' plants in service in South Carolina (SC) and North Carolina (NC) with plant statistics, and the system's total generating capability.

Existing Generating Units and Ratings [1, 3]
All Generating Unit Ratings are as of July 1, 2018 unless otherwise noted.

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	668	Semora, NC	Coal	Intermediate
Roxboro	3	698	694	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	160	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	50	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	2	64	48	Hartsville, SC	Oil	Peaking
Darlington	3	63	50	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	4	66	48	Hartsville, SC	Oil	Peaking
Darlington	6	62	43	Hartsville, SC	Oil	Peaking
Darlington	7	65	47	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	8	66	44	Hartsville, SC	Oil	Peaking
Darlington	10	65	49	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	189	157	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	2	187	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	187	145	Hamlet, NC	Natural Gas/Oil	Peaking
Sutton	4	49	39	Wilmington, NC	Natural Gas/Oil	Peaking
Sutton	5	49	39	Wilmington, NC	Natural Gas/Oil	Peaking
Wayne	1/10	192	177	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	2/11	192	174	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	3/12	193	173	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	4/13	191	170	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	5/14	195	163	Goldsboro, NC	Oil/Natural Gas	Peaking
Weatherspoon	1	41	31	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	2	41	31	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	3	41	32	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	4	41	30	Lumberton, NC	Natural Gas/Oil	Peaking
Total NC		2,597	2,203			
Total SC		780	613			
Total CT		3,377	2,816			

Combined Cycle						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Lee	CT1A	225	170	Goldsboro, NC	Natural Gas/Oil	Base
Lee	CT1B	227	170	Goldsboro, NC	Natural Gas/Oil	Base
Lee	CT1C	228	170	Goldsboro, NC	Natural Gas/Oil	Base
Lee	ST1	379	378	Goldsboro, NC	Natural Gas/Oil	Base
Smith [4]	CT7	189	154	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT8	189	153	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	ST4	175	169	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT9	216	174	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT10	216	175	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	ST5	248	248	Hamlet, NC	Natural Gas/Oil	Base
Sutton	CT1A	224	170	Wilmington, NC	Natural Gas/Oil	Base
Sutton	CT1B	224	171	Wilmington, NC	Natural Gas/Oil	Base
Sutton	ST1	271	266	Wilmington, NC	Natural Gas/Oil	Base
Total CC		3,011	2,568			

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	980	932	New Hill, NC	Uranium	Base
Robinson	2	797	741	Hartsville, SC	Uranium	Base
Total NC		2,908	2,802			
Total SC		797	741			
Total Nuclear		3,705	3,543			

Solar						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
NC Solar		7.1	62.0	NC	Solar	Intermittent

Total Generation Capability		
	Winter Capacity (MW)	**Summer Capacity (MW)**
TOTAL DEP SYSTEM - N.C.	12,342	11,406
TOTAL DEP SYSTEM - S.C.	1,577	1,354
TOTAL DEP SYSTEM	13,919	12,760

Note 1: Ratings reflect compliance with NERC reliability standards.

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.

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

Note 5: Solar capacity ratings reflect contribution to winter and summer peak values.

Planned Uprates			
Unit	**Completion Date**	**Winter MW**	**Summer MW**
Brunswick 1 [1]	Spring 2020	4	2
Brunswick 2 [1]	Spring 2019	6	4
Brunswick 2 [1]	Spring 2023	6	4
Brunswick 2 [1]	Spring 2027	4	2
Brunswick 2 [1]	Spring 2021	6	4
Harris 1[1]	Spring 2018	30	30

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 5	Hartsville, SC	66	51	Combustion Turbine	5/31/2018
Darlington 9	Hartsville, SC	65	50	Combustion Turbine	6/30/17
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
Sutton GT1	Wilmington, NC	12	11	Combustion Turbine	3/1/2017
Sutton GTA	Wilmington, NC	31	23	Combustion Turbine	7/8/2017
Sutton GTB	Wilmington, NC	33	25	Combustion Turbine	7/8/2017
Total		2,154 MW	1,972 MW		

Planning Assumptions – Unit Retirements [a, b]					
Unit & Plant Name	**Location**	**Winter Capacity (MW)**	**Summer Capacity (MW)**	**Fuel Type**	**Expected Retirement**
Asheville 1	Arden, N.C.	192	189	Coal	11/2019
Asheville 2	Arden, N.C.	192	189	Coal	11/2019
Mayo 1	Roxboro, N.C.	746	727	Coal	12/2035
Roxboro 1	Semora, N.C.	380	379	Coal	12/2028
Roxboro 2	Semora, N.C.	673	665	Coal	12/2028
Roxboro 3	Semora, N.C.	698	691	Coal	12/2033
Roxboro 4	Semora, N.C.	711	698	Coal	12/2033
Darlington 1	Hartsville, S.C.	63	52	Natural Gas/Oil	12/2020
Darlington 2	Hartsville, S.C.	64	48	Oil	12/2020
Darlington 3	Hartsville, S.C.	63	52	Natural Gas/Oil	12/2020
Darlington 4	Hartsville, S.C.	66	50	Oil	12/2020
Darlington 6	Hartsville, S.C.	62	45	Oil	12/2020
Darlington 7	Hartsville, S.C.	65	51	Natural Gas/Oil	12/2020
Darlington 8	Hartsville, S.C.	66	48	Oil	12/2020
Darlington 10	Hartsville, S.C.	65	51	Oil	12/2020
Blewett 1	Lilesville, N.C.	17	13	Oil	12/2024
Blewett 2	Lilesville, N.C.	17	13	Oil	12/2024
Blewett 3	Lilesville, N.C.	65	13	Oil	12/2024
Blewett 4	Lilesville, N.C.	66	13	Oil	12/2024
Weatherspoon 1	Lumberton, N.C.	41	32	Natural Gas/Oil	12/2024
Weatherspoon 2	Lumberton, N.C.	41	32	Natural Gas/Oil	12/2024
Weatherspoon 3	Lumberton, N.C.	41	33	Natural Gas/Oil	12/2024
Weatherspoon 4	Lumberton, N.C.	41	31	Natural Gas/Oil	12/2024
Total		4,435	4,115		

Note a: Retirement assumptions are for planning purposes only; retirement dates are based on the depreciation study approved as part of the most recent DEP rate case.

Note b: For planning purposes, the 2018 IRP Base Case assumes subsequent license renewal for existing nuclear facilities beginning at end of current operating licenses.

Planning Assumptions – Unit Additions					
Unit & Plant Name	**Location**	**Winter Capacity (MW)**	**Summer Capacity (MW)**	**Fuel Type**	**Expected Commercial Date**
Asheville CC	Arden, N.C.	560	495	Natural Gas	11/2019

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	April 2015	2055
Tillery #1-4 [1]	Mr. Gilead, NC	04/30/08	April 2015	2055
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 for the Blewett and Tillery Plants was received in April 2015. The license extension was granted for 40 years.

APPENDIX C: ELECTRIC LOAD FORECAST

Methodology:

The Duke Energy Progress Spring 2018 load forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2019 – 2033 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.

The economic projections used in the Spring 2018 Forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of South and North Carolina.

Moody's Analytics supplies the Company with economic and demographic projections, which are used in the energy and demand models. Preliminary analysis of Moody's historical projections versus actuals resulted in smaller variances and minimum bias during normal economic periods. However, the likelihood of greater forecast variance and forecast bias increases during unique disruptive economic periods like the Great Recession. The Load Forecasting team will continue to monitor Moody's forecast error going forward.

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

The Residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electricity prices 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 average annual growth rate of residential in the Spring 2018 forecast, including the impacts of Utility Energy Efficiency programs (UEE), rooftop solar and electric vehicles from 2019-2033 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 energy sales are expected to grow 0.6% per year over the forecast horizon.

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 0.2% per year over the forecast horizon.

Weather impacts are incorporated into the models by using Heating Degree Days with a base temperature of 59 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. 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.

Forecast Enhancements:

In 2013, The Company began using the statistically adjusted end use (SAE) projections to forecast sales and peaks. The end use models provide a better platform to recognize trends in equipment appliance saturation and changes to efficiencies, and how those trends interact with heating, cooling, and "other" or non-weather-related sales. The appliance saturation and efficiency trends are developed by ITRON using data from 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. In conjunction with peer utilities and ITRON, the company continually looks for refinements to its modeling procedures to make better use of the forecasting tools, and develop more reliable forecasts.

Each time the forecast is updated, the most currently available historical and projected data is used. The current 2018 forecast utilizes:

- Moody's Analytics January 2018 base and consensus economic projections.
- End use equipment and appliance indexes reflect the 2017 update of ITRON's end-use data, which is consistent with the Energy Information Administration's 2017 Annual Energy Outlook
- A calculation of normal weather using the period 1987-2016

As instructed by the North Carolina Utilities Commission after review of the 2016 IRP, the Company continues to research the weather sensitivity of summer and winter peaks, hourly shaping of sales and load research data. As a result of the study, several improvements were identified and incorporated into the current forecast, as follows:

- **Retail Peak Weather Normalization**
    - The peak weather Rank/Sort process was updated using the ITRON forecasting software rank/sort functionality. For purposes of projecting peaks, a seasonal rank/sort approach was used to capture historical weather patterns that may have occurred outside of the normal peak month.
    - The peak model was updated to capture the actual historical average daily temperature on the day of peak. Previous models selected the coldest average daily temperature during the month of peak.

- **Load History –** Conducted a detailed review of historical loads, and the definitions of the loads in order to better align historical results with future projections.

- **Wholesale Assumptions -** The wholesale forecast process was better integrated with the retail forecast process. Additional reporting detail was provided for wholesale history and wholesale customer classes, resulting in an improved load shape.

After completing the study, it was determined that historical winter peaks were coming in well above forecasted peaks. Several process improvements above addressed that issue, raising the winter peaks in the 2018 Spring Forecast compared to the 2017 Spring Forecast.

Assumptions:

Below are the projected average annual growth rates of several key drivers from DEP's Spring 2018 Forecast.

	2019-2033
Real Income	2.3%
Manufacturing Industrial Production Index (IPI)	1.1%
Population	1.3%

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.

Utility Energy Efficiency:

Utility Energy Efficiency Programs continue to have a large impact in the acceleration of the adoption of energy efficiency. When including the impacts of UEE on energy and peaks, careful attention must be paid to avoid the double counting of UEE efficiencies with the naturally occurring efficiencies included in the SAE modeling approach. To ensure there is not a double counting of these efficiencies, the forecast "rolls off" the UEE savings at the conclusion of its measure life. For example, if the accelerated benefit of a residential UEE program is expected to have occurred seven years before the energy reduction program would have been otherwise adopted, then the UEE effects after year seven are subtracted ("rolled off") from the total cumulative UEE. With the SAE model's 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 on sales:

Table C-1: UEE Program Life Process (MWh)

	A	B	C	D	E	F	G
Year	Forecast Before UEE	Historical UEE Roll Off	Forecast With Historical Roll Off	Forecasted UEE Incremental Roll on	Forecasted UEE Incremental Roll Off	UEE to Subtract From Forecast	Forecast After UEE
2019	64,378	8	64,386	(348)	-	(348)	64,038
2020	64,173	38	64,212	(543)	0	(543)	63,669
2021	64,243	97	64,340	(728)	0	(728)	63,613
2022	64,104	193	64,297	(905)	2	(903)	63,393
2023	64,558	325	64,884	(1,080)	5	(1,075)	63,809
2024	65,390	478	65,868	(1,256)	10	(1,246)	64,622
2025	65,963	631	66,594	(1,431)	16	(1,416)	65,178
2026	65,956	769	66,725	(1,607)	26	(1,581)	65,145
2027	66,593	875	67,468	(1,782)	41	(1,742)	65,726
2028	67,530	944	68,473	(1,958)	78	(1,880)	66,593
2029	68,096	985	69,081	(2,134)	133	(2,001)	67,080
2030	68,654	1,003	69,657	(2,311)	202	(2,109)	67,548
2031	69,300	1,009	70,309	(2,488)	288	(2,201)	68,108
2032	70,060	1,009	71,069	(2,668)	386	(2,282)	68,787
2033	70,461	1,009	71,470	(2,848)	503	(2,345)	69,125

Wholesale:

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

Customer Growth:

Tables C-2 and C-3 show the history and projections for DEP customers.

Table C-2: Retail Customers (Annual Average in Thousands)

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2008	1,195	216	4	2	1,417
2009	1,207	215	5	2	1,429
2010	1,216	216	5	2	1,439
2011	1,221	217	4	2	1,445
2012	1,231	219	4	2	1,457
2013	1,242	222	4	2	1,470
2014	1,257	223	4	2	1,486
2015	1,275	226	4	2	1,507
2016	1,292	229	4	2	1,527
2017	1,310	232	4	1	1,547
Avg. Annual Growth Rate	1.0%	0.8%	-0.3%	-4.4%	1.0%

Table C-3: Retail Customers (Annual Average in Thousands)

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2019	1,345	237	4	1	1,588
2020	1,361	240	4	1	1,607
2021	1,376	243	4	1	1,625
2022	1,392	246	4	1	1,643
2023	1,406	248	4	1	1,660
2024	1,420	251	4	1	1,676
2025	1,433	253	4	1	1,692
2026	1,445	256	4	1	1,706
2027	1,457	258	4	1	1,720
2028	1,469	261	4	1	1,735
2029	1,480	263	4	1	1,748
2030	1,492	265	4	1	1,762
2031	1,503	268	4	1	1,776
2032	1,514	270	4	1	1,789
2033	1,526	272	4	1	1,789
Avg. Annual Growth Rate	0.8%	0.9%	-1.0%	-0.2%	0.8%

Electricity Sales:

Table C-4 shows the actual historical GWh sales. As a note, the values in Table C-2 are not weather adjusted Sales.

Table C-4: Electricity Sales (GWh)

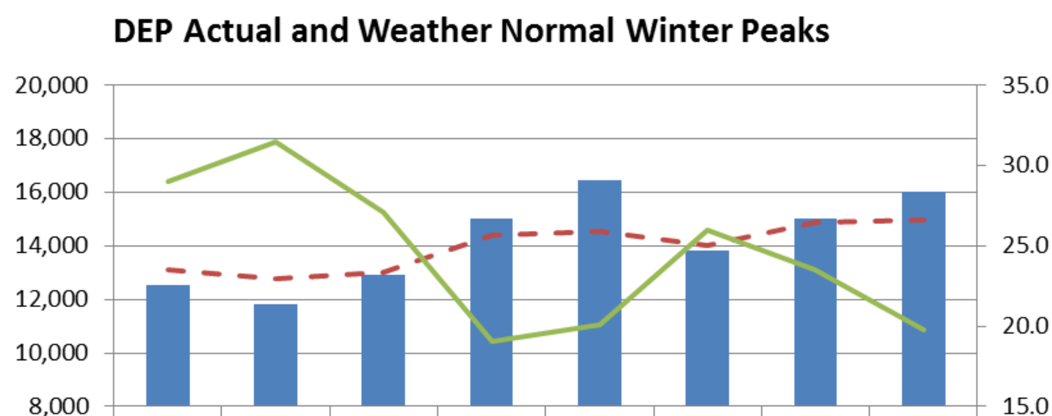
Year	Residential GWh	Commercial GWh	Industrial GWh	Military & Other GWh	Retail GWh	Wholesale GWh	Total System GWh
2008	17,200	14,033	11,883	1,438	44,553	12,656	57,209
2009	17,000	13,940	11,216	1,467	43,622	12,868	56,489
2010	17,117	13,639	10,375	1,497	42,628	12,772	55,400
2011	19,108	14,184	10,677	1,574	45,544	12,772	58,316
2012	17,764	13,709	10,573	1,591	43,637	12,267	55,903
2013	16,663	13,581	10,508	1,602	42,355	12,676	55,031
2014	18,201	13,887	10,321	1,614	44,023	13,578	57,601
2015	17,954	14,039	10,288	1,597	43,876	15,782	59,658
2016	17,686	14,082	10,274	1,563	43,606	18,676	62,282
2017	17,228	13,903	10,391	1,531	43,053	18,242	61,295
Avg. Annual Growth Rate	0.0%	-0.1%	-1.5%	0.7%	-0.4%	4.1%	0.8%

Note: The wholesale values in Table C-4 exclude NCEMPA sales for all years before 2015, and is only partially included in 2015.

System Peaks:

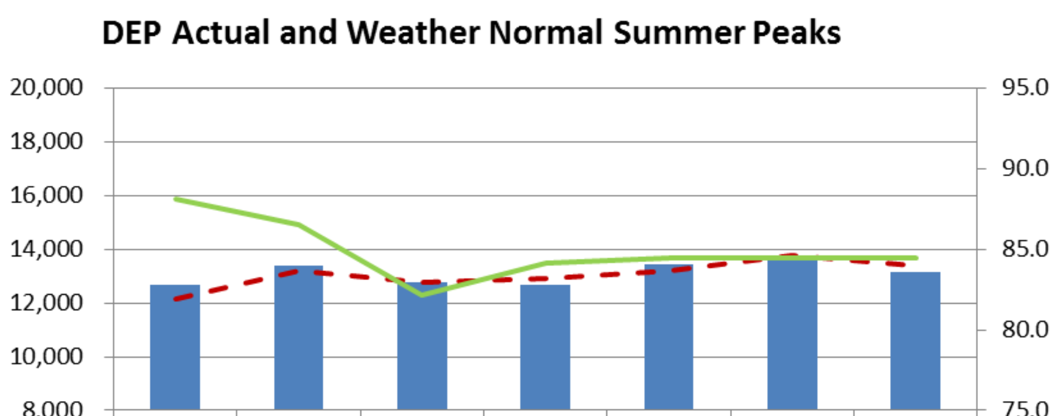
Table C-5 and C-6 shows the historical actual and weather normalized peaks for the system:

Table C-5: Winter Peaks



	2011	2012	2013	2014	2015	2016	2017	2018
Actual	12,522	11,826	12,897	14,993	16,429	13,801	15,020	16,016
WN Peak	13,107	12,760	12,994	14,374	14,519	14,026	14,857	14,967
Temp	29.0	31.5	27.1	19.1	20.1	26.0	23.5	19.8

Table C-6: Summer Peaks



	2011	2012	2013	2014	2015	2016	2017
Actual	12,686	13,405	12,785	12,663	13,415	13,578	13,143
WN Peak	12,146	13,198	12,757	12,922	13,206	13,777	13,375
Temp	88.1	86.5	82.2	84.1	84.5	84.5	84.4

Forecast Results:

A tabulation of the Company's sales and peak forecasts are shown as tables below:

- Table C-7: Forecasted energy sales by class (Including the impacts of UEE, rooftop solar, and electric vehicles)
- Table C-8: Summary of the load forecast without UEE programs and excluding any impacts from demand reduction programs
- Table C-9: Summary of the load forecast with UEE programs and excluding any impacts from demand reduction programs

These projections are at generation and include Wholesale.

Load duration curves, with and without UEE programs are shown as Figures 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 2019 to 2033.

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

Table C-7: Forecasted Energy Sales by Class

Year	Residential GWh	Commercial GWh	Industrial GWh	Other GWh	Retail GWh
2019	18,016	14,007	10,511	1,532	44,065
2020	18,236	14,073	10,591	1,524	44,425
2021	18,395	14,073	10,476	1,516	44,459
2022	18,638	14,120	10,433	1,507	44,697
2023	18,905	14,173	10,307	1,499	44,884
2024	19,234	14,303	10,388	1,490	45,416
2025	19,444	14,387	10,445	1,488	45,764
2026	19,686	14,515	10,514	1,483	46,197
2027	19,907	14,635	10,528	1,478	46,548
2028	20,176	14,813	10,661	1,475	47,125
2029	20,327	14,916	10,701	1,471	47,415
2030	20,532	15,003	10,700	1,465	47,700
2031	20,742	15,102	10,764	1,462	48,070
2032	21,015	15,236	10,819	1,458	48,528
2033	21,178	15,292	10,769	1,452	48,692
Avg. Annual Growth Rate	1.1%	0.6%	0.2%	-0.4%	0.7%

Note: Values are at meter

Table C-8: Summary of Load Forecast (without UEE programs and excluding any impacts from demand reduction programs)

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2019	13,374	14,036	64,386
2020	13,409	14,060	64,212
2021	13,439	14,062	64,340
2022	13,557	14,168	64,297
2023	13,676	14,243	64,884
2024	13,850	14,429	65,868
2025	14,018	14,553	66,594
2026	14,264	14,724	66,725
2027	14,398	14,886	67,468
2028	14,642	15,090	68,473
2029	14,804	15,232	69,081
2030	14,959	15,367	69,657
2031	15,137	15,524	70,309
2032	15,333	15,704	71,069
2033	15,463	15,811	71,470
Avg. Annual Growth Rate	1.0%	0.8%	0.7%

Note: Values are at generation level

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

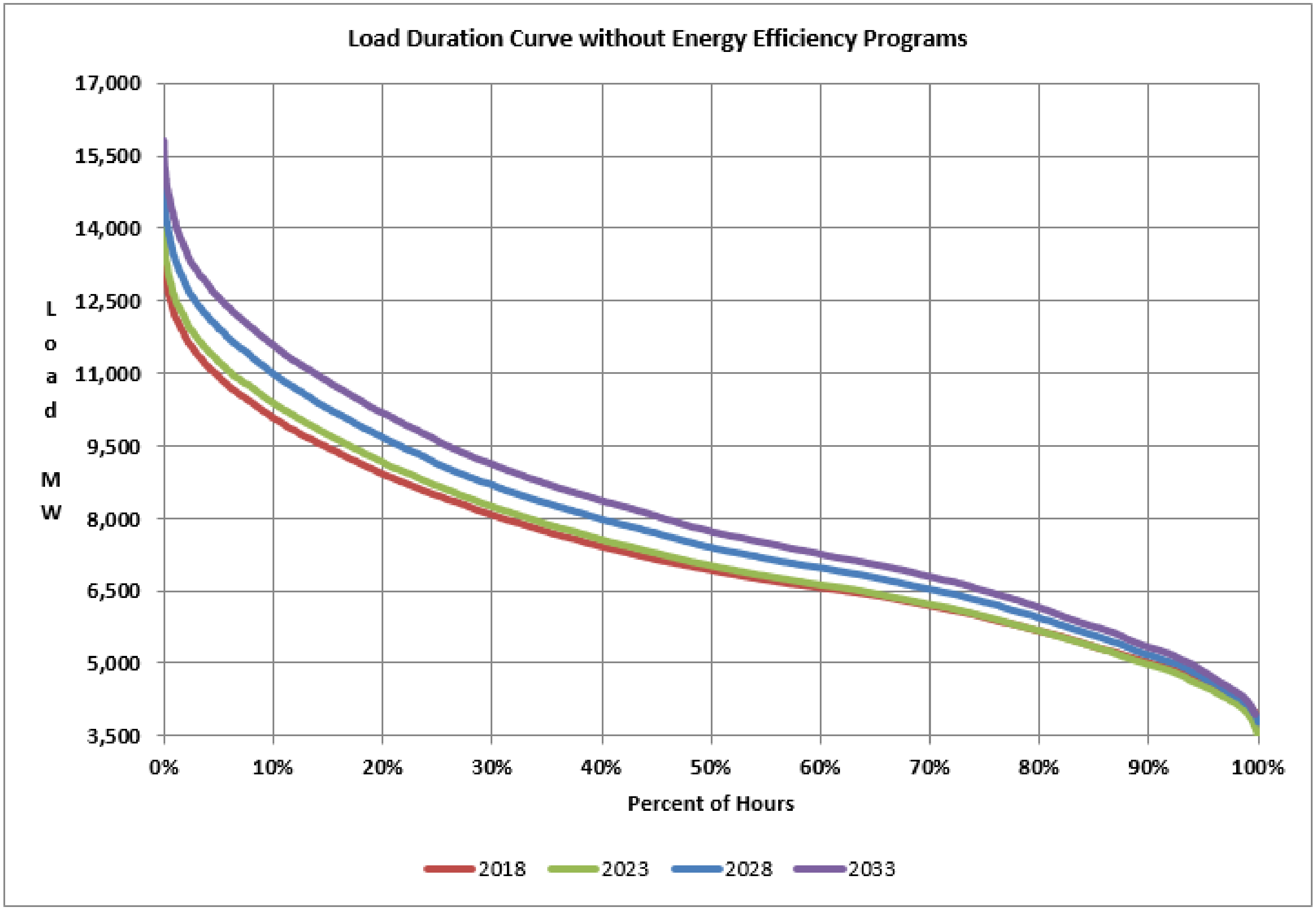
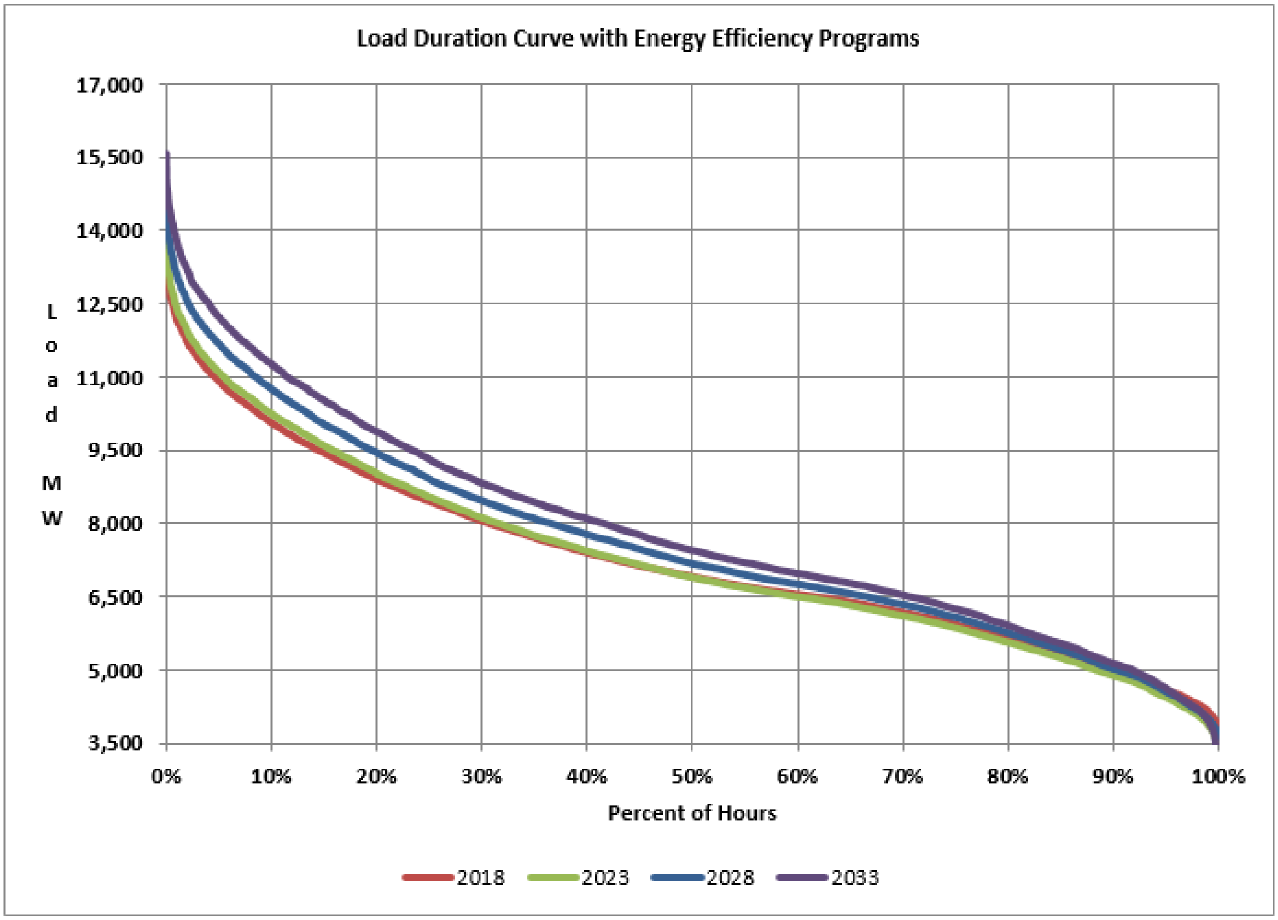


Table C-9: Summary of Load Forecast (with UEE programs and excluding any impacts from demand reduction programs)

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2019	13,317	14,011	64,038
2020	13,322	14,016	63,669
2021	13,324	14,001	63,613
2022	13,416	14,089	63,393
2023	13,510	14,139	63,809
2024	13,658	14,308	64,622
2025	13,796	14,415	65,178
2026	14,014	14,568	65,145
2027	14,118	14,713	65,726
2028	14,336	14,903	66,593
2029	14,473	15,032	67,080
2030	14,605	15,155	67,548
2031	14,762	15,303	68,108
2032	14,941	15,475	68,787
2033	15,054	15,575	69,125
Avg. Annual Growth Rate	0.8%	0.7%	0.5%

Note: Values are at generation level

Figure C-2: Load Duration Curve with Energy Efficiency Programs and 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 (DSM) and energy efficiency (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 EE Programs:

- Energy Efficiency Education
- Multi-Family Energy Efficiency
- My Home Energy Report
- Neighborhood Energy Saver (Low-Income)
- Residential Energy Assessments
- Residential New Construction
- Residential Smart $aver® Energy Efficiency
- Save Energy and Water Kit

Non-Residential EE Programs:

- Non-Residential Smart $aver® Energy Efficiency Products and Assessment
- Non-Residential Smart $aver® Performance Incentive
- Small Business Energy Saver

Combined Residential/Non-Residential EE Programs:

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

Residential DSM Programs:

- EnergyWise[SM] Home

Non-Residential DSM Programs:

- CIG Demand Response Automation
- EnergyWise[SM] for Business

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 2017 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 the 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:

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 is a live

[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.

theatrical production focused on concepts such as energy, renewable fuels and energy efficiency performed by two professional actors.

Following the performance, students are encouraged to complete a home energy survey with their family to receive an Energy Efficiency Starter Kit. The kit contains specific energy efficiency measures to reduce home energy consumption and is available at no cost to student households at participating schools. Teachers receive supportive educational material for classroom and student take home assignments. The workbooks, assignments and activities meet state curriculum requirements.

Energy Efficiency Education			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2017	29,049	8,439	3,572

Multi-Family Energy Efficiency Program:

The Multi-Family Energy Efficiency Program provides energy efficient lighting and water measures to reduce energy usage in eligible multi-family properties. The Program allows Duke Energy Progress to target multi-family apartment complexes with an alternative delivery channel. The measures are installed in permanent fixtures by the program administrator or the property management staff. The program offers LEDs including A-Line, Globes and Candelabra bulbs and energy efficient water measures such as bath and kitchen faucet aerators, water saving showerheads and pipe wrap.

Multi-Family Energy Efficiency			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2017	885,774	48,814	6,042

My Home Energy Report Program:

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

The program includes an interactive online portal that allows customers to further engage and learn more about their energy use and opportunities to reduce usage. Electronic versions of the My Home Energy Report are sent to customers enrolled on the portal. In addition, all MyHER customers with an email address on file with the Company receive an electronic version of their report monthly.

My Home Energy Report			
	Number of	Gross Savings (at plant)	
Capability as of:	Participants	MWh Energy	Peak kW
December 31, 2017	795,734	117,852	19,964

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.

Neighborhood Energy Saver			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	37,278	18,479	2,648

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 and 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.

Residential Energy Assessments			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	65,704	9,590	1,602

Residential New Construction Program:

The Residential New Construction Program provides incentives for new single family and multi-family residential dwellings (projects of three stories and less) that fall within the 2012 North Carolina Residential Building Code to meet or exceed the 2012 North Carolina Energy Conservation Code High Efficiency Residential Option (HERO). If a builder or developer constructing to the HERO standard elects to participate, the Program offers the homebuyer an incentive guaranteeing the heating and cooling consumption of the dwelling's total annual energy costs. Additionally, the Program incents the installation of high-efficiency heating ventilating and air conditioning (HVAC) and heat pump water heating (HPWH) equipment in new single family, manufactured, and multi-family residential housing units.

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 costlier to install at a later time.

Residential New Construction			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	15,498,975	42,889	17,187

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

Residential Smart $aver® EE Program (formerly known as the Home Energy Improvement Program):

The Residential Smart $aver® EE Program offers DEP customers a variety of energy conservation measures designed to increase energy efficiency in existing residential dwellings. The Program utilizes a network of participating contractors to encourage the installation of: (1) high efficiency central air conditioning (AC) and heat pump systems with optional add on measures such as Quality Installation and Smart Thermostats, (2) attic insulation and sealing, (3) heat pump water heaters, and (4) high efficiency variable speed pool pumps.

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. A referral channel provides free, trusted referrals to customers seeking reliable, qualified contractors for their energy saving home improvement needs.

This program previously offered HVAC Audits and Room ACs, however, those measures were removed due to no longer being cost-effective.

The tables below show actual program performance for all current and past program measures.

Residential Smart $aver® EE			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	160,600	67,315	39,696

Save Energy and Water 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, shower heads, kitchen aerators and pipe insulation tape. The program has a website in place that customers can access to learn more about the program or watch videos produced to aid in the installation of the kit measures.

Save Energy and Water Kit			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	789,000	45,710	15,301

Non-Residential EE Programs:

Non-Residential Smart $aver Energy Efficient Products and Assessment Program *(formerly known as the Energy Efficiency for Business Program)*

The Non-Residential Smart $aver Energy Efficient Products and Assessment 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 Prescriptive 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 the Prescriptive portion of the program, all Custom measure incentives require pre-approval prior to the project implementation.

- *Energy Assessments and Design Assistance*: Incentives are available to assist customers with energy studies such as energy audits, retro commissioning, and system-specific energy audits for existing buildings and with design assistance such as energy modeling for new construction. Customers may use a contracted Duke Energy vendor to perform the work or they may select their own vendor. Additionally, the Program assists customers who identify measures that may qualify for Smart $aver Incentives with their applications. Pre-approval is required.

Non-Residential Smart $aver® Energy Efficient Products and Assessment			
		Gross Savings (at plant)	
Cumulative as of:	**Number of Participants***	**MWh Energy**	**Peak kW**
December 31, 2017	73,365,213	569,826	102,244

* Note: Participants have different units of measure.

Non-Residential Smart $aver Performance Incentive Program:

The Non-Residential Smart $aver® Performance Incentive Program offers financial assistance to qualifying commercial, industrial and institutional customers to enhance their ability to adopt and install cost-effective electrical energy efficiency projects. The Program encourages the installation of new high efficiency equipment in new and existing nonresidential establishments as well as efficiency-related repair activities designed to maintain or enhance efficiency levels in currently installed equipment. Incentive payments are provided to offset a portion of the higher cost of energy efficient installations that are not eligible under the Smart $aver® EE Products and Assessment program. The Program requires pre-approval prior to project initiation.

The types of projects covered by the Program include projects with some combination of unknown building conditions or system constraints, or uncertain operating, occupancy, or production schedules. The intent of the Program is to broaden participation in non-residential efficiency programs by being able to provide incentives for projects that previously were deemed too unpredictable to calculate an acceptably accurate savings amount, and therefore ineligible for incentives. This Program provides a platform to understand new technologies better. Only projects that demonstrate that they clearly reduce electrical consumption and/or demand are eligible for incentives.

The key difference between this program and the custom component of the Non-Residential Smart $aver Energy® Efficient Products and Assessment program is that Performance Incentive participants get paid based on actual measure performance, and involves the following two step process.

- Incentive #1: For the portion of savings that are expected to be achieved with a high degree of confidence, an initial incentive is paid once the installation is complete.
- Incentive #2: After actual performance is measured and verified, the performance-based part of the incentive is paid. The amount of the payout is tied directly to the savings achieved by the measures.

Non-Residential Smart $aver® Performance Incentive			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants*	MWh Energy	Peak kW
December 31, 2017	1	440	59

Small Business Energy Saver Program

The Small Business Energy Saver Program reduces energy usage through the direct installation of energy efficiency measures within qualifying 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 180 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. The customer makes the final determination of which measures will be installed after receiving the results of the energy assessment. The Company-authorized vendor schedules the installation of the energy efficiency measures at a convenient time for the customer, and electrical subcontractors perform the work.

Small Business Energy Saver			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	126,301,579	191,477	37,247

Note: Participants have different units of measure.

Combined Residential/Non-Residential Customer:

Energy Efficient Lighting Program:

The Energy Efficient Lighting Program partners with lighting manufacturers and retailers across North and South Carolina to provide marked-down prices at the register to DEP customers purchasing energy efficient lighting products. Starting in 2017, the Program removed CFLs and only offers LEDs and energy-efficient fixtures.

As the program enters its eighth year, the DEP Energy Efficient Lighting Program will continue to encourage customers to adopt energy efficient lighting through incentives on a wide range of energy efficient 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			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2017	29,776,479	1,636,739	255,409

Distribution System Demand Response Program (DSDR):

Duke Energy Progress' Distribution System Demand Response (DSDR) program manages the application and operation of voltage regulators (the Volt) and capacitors (the VAR) on the Duke Energy Progress distribution system. In general, the program 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.

Distribution System Demand Response			
		Gross Savings (at plant)	
Cumulative as of:	Number of Participants	MWh Energy	Summer MW Capability
December 31, 2017	NA	35,519	212

Since DEP's last biennial resource plan was filed on September 2, 2016, there have been 35 voltage control activations through June 30, 2018. The following table shows the date, starting and ending time, and duration for all voltage control activations from July 2016 through June 2018.

Voltage Control Activations			
Date	Start Time	End Time	Duration (H:MM)
7/5/2016	14:00	14:13	0:13
7/26/2016	15:30	19:11	3:41
7/27/2016	15:30	19:15	3:45
7/28/2016	15:30	19:00	3:30
8/19/2016	17:53	18:01	0:08
8/24/2016	13:42	14:00	0:18
11/22/2016	6:00	8:30	2:30
12/21/2016	9:00	10:00	1:00
1/8/2017	6:30	9:46	3:16
1/9/2017	6:30	9:37	3:07
3/16/2017	6:00	8:30	2:30
5/4/2017	13:00	14:30	1:30
5/12/2017	13:00	14:00	1:00
8/18/2017	16:00	19:00	3:00
10/9/2017	16:30	19:30	3:00
10/11/2017	16:00	20:00	4:00

Voltage Control Activations			
Date	**Start Time**	**End Time**	**Duration (H:MM)**
10/12/2017	16:00	20:00	4:00
10/23/2017	18:00	21:00	3:00
1/1/2018	19:00	22:00	3:00
1/2/2018	5:00	10:30	5:30
1/2/2018	19:00	22:00	3:00
1/3/2018	5:00	9:00	4:00
1/3/2018	19:00	22:00	3:00
1/4/2018	5:00	9:00	4:00
1/4/2018	19:00	22:00	3:00
1/5/2018	5:00	10:00	5:00
1/5/2018	19:00	22:00	3:00
1/6/2018	5:00	10:00	5:00
1/7/2018	5:00	10:00	5:00
1/14/2018	6:00	10:00	4:00
1/15/2018	5:00	9:00	4:00
1/16/2018	5:00	9:00	4:00
1/17/2018	18:00	22:00	4:00
1/18/2018	5:00	9:00	4:00
3/9/2018	5:30	8:30	3:00
3/13/2018	6:00	8:30	2:30
3/15/2018	6:00	8:30	2:30
3/22/2018	6:00	8:20	2:20
6/18/2018	16:30	20:00	3:30
6/19/2018	16:30	20:00	3:30
6/20/2018	16:30	20:00	3:30

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.

EnergyWise[SM] Home			
Cumulative as of:	**Number of Participants***	**2017 Capability (MW@Gen)**	
		Summer	**Winter**
December 31, 2017	179,409	347	13.1

* 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, 2016 through December 31, 2017.

EnergyWise[SM] Home Program Activations				
Date	**Start Time**	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
7/24/2016	4:00 pm	6:00 pm	120	115
7/24/2016	6:00 pm	7:00 pm	60	1
9/8/2016	3:00 pm	6:00 pm	180	141
1/9/2017	6:30 am	9:30 am	180	11.6
8/21/2017	2:00 pm	3:30 pm	90	120.5

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.

CIG Demand Response Automation Statistics			
	Number of	MW Capability	
Cumulative as of:	Participants	Summer	Winter
December 31, 2017	71	22.8	13.2

The table below shows information for each CIG Demand Response Automation Program non-test control event from July 1, 2016 through December 31, 2017.

CIG Demand Response Automation – Curtailable Option				
Date	Start Time	End Time	Duration (Minutes)	MW Load Reduction
7/8/2016	1:00 pm	7:00 pm	360	21.6
7/26/2016	1:00 pm	7:00 pm	360	17.5
7/13/2017	1:00 pm	7:00 pm	360	18.9
7/21/2017	1:00 pm	7:00 pm	360	21.1
8/18/2017	1:00 pm	7:00 pm	360	23.4

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.

EnergyWise^{SM} for Business				
Cumulative as of:	Participants*	MW Capability		MWh Energy Savings (at plant)
		Summer	Winter	
December 31, 2017	2,302	3.4	0.6	1,400

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

The following table shows EnergyWise^{SM} for Business program activations that were not for testing purposes from July 1, 2016 through December 31, 2017.

EnergyWise^{SM} for Business Program Activations				
Date	Start Time	End Time	Duration (Minutes)	MW Load Reduction
7/8/2016	3:30 pm	6:00 pm	150	0.3
7/14/2016	3:00 pm	6:00 pm	180	0.3
7/27/2016	3:00 pm	6:00 pm	180	0.3
6/14/2017	3:00 pm	6:00 pm	180	2.6
7/13/2017	3:00 pm	6:00 pm	180	2.6
7/21/2017	3:00 pm	6:00 pm	180	2.6
8/17/2017	3:30 pm	6:00 pm	150	2.6
8/22/2017	3:00 pm	6:00 pm	180	2.6

Discontinued Demand-Side Management and Energy Efficiency Programs:

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

- **Appliance Recycling** – The Appliance Recycling Program promoted the removal and responsible disposal of operating refrigerators and freezers from DEP residential customers. The Program recycled approximately 95% of the material from the harvested appliances.

The implementation vendor for this program abruptly discontinued operations in November 2015 and the program was subsequently closed. The table below presents the final actual program accomplishments.

Residential Appliance Recycling			
	Number of	Gross Savings (at plant)	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2017	48,022	51,127	6,098

- **Business Energy Report Pilot** – The Business Energy Report Pilot consisted of a periodic comparative usage report that compares a customer's energy use to their peer groups. Comparative groups were 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 received targeted energy efficiency tips in their report informing them of actionable ideas to reduce their energy consumption.

  With the cost effectiveness of the program declining below the allowable threshold, the program was terminated in 2017. Due to the program having a one-year measures life, there are no ongoing savings associated with the program.

- **CIG Demand Response Automation – Generator Option** – 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. 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 led DEP to close the program option and revise the rider to include only the incentive structure associated with the former Curtailable Option. The NCUC approved terminating this program measure effective September 2016, in response to the changes in EPA regulations.

DSM/EE Programs Prior to NC Senate Bill 3:

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. There were no curtailable rate activations during the period from July 1, 2016 through December 31, 2017.

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.

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 2017, 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	Summer Capacity (MW)	Winter Capacity (MW)	Annual Energy (MWH)	Participants	Activations Since Last Biennial Report
Energy Efficiency Programs[11]	EE	466	N/A	NA	NA	NA
Real Time Pricing (RTP)	DSM	53	62	NA	105	NA
Commercial & Industrial TOU	DSM	10.9	10.9	NA	30,749	NA
Residential TOU	DSM	6.2	6.2	NA	28,011	NA
Curtailable Rates	DSM	284	241	NA	61	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.

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

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 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:

Forecast Methodology:

In 2016, DEP commissioned a new EE market potential study to obtain new estimates of the technical, economic and achievable potential for EE savings within the DEP service area. The final reports (one for South Carolina and one for North Carolina) were prepared by Nexant Inc. and issued on December 19, 2016.

The Nexant 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.

The Nexant market potential study (MPS) included projections of energy efficiency impacts over a 25-year period for a Base and Enhanced Scenario, which were used in conjunction with expected EE savings from DEP's five-year program plan to develop the Base Case and High Case EE savings forecasts, respectively, for this IRP. The Base Case EE savings forecast represents a merging of the projected near-term savings from DEP's five-year plan (2018-2022) with the long-term savings from the Nexant MPS (2028-onward). Savings during the five-year period (2023-2027) between the two sets of projections represents a merging of the two forecasts to ensure a smooth transition. The High Case EE savings forecast was developed by applying the difference between the Nexant Enhanced and Base Scenarios for all years to the final DEP Base Case forecast. Additionally, the cumulative savings projections for both the Base and High Case EE forecasts 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, a process defined as "rolloff".

The table below provides the projected MWh load impacts for both the Base Case and High Case forecasts of all DEP EE programs implemented since 2008 on a Net of Free Riders basis. The

Company assumes total EE savings will continue to grow on an annual basis throughout the planning, 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 2008 through the end of 2017, which accounts for approximately an additional 2,117 gigawatt-hour (GWh) of net energy savings.

The following forecast is presented without the effects of "rolloff":

Projected MWh Impacts of EE Programs

Base Case

	Annual MWh Load Reduction - Net	
Year	Including measures added in 2018 and beyond	Including measures added since 2008
2008-17		2,116,891
2018	230,996	2,347,887
2019	422,130	2,539,021
2020	605,468	2,722,359
2021	777,345	2,894,236
2022	945,787	3,062,678
2023	1,114,230	3,231,121
2024	1,282,674	3,399,565
2025	1,451,119	3,568,010
2026	1,619,565	3,736,456
2027	1,788,012	3,904,903
2028	1,956,460	4,073,351
2029	2,125,763	4,242,654
2030	2,295,309	4,412,200
2031	2,466,556	4,583,447
2032	2,639,409	4,756,301
2033	2,812,935	4,929,826

The MWh totals included in the table 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.

Projected MWh Impacts of EE Programs
High Case

Year	Annual MWh Load Reduction - Net	
	Including measures added in 2018 and beyond	Including measures added since 2008
2008-17		2,116,891
2018	322,259	2,439,151
2019	609,785	2,726,676
2020	892,927	3,009,818
2021	1,170,540	3,287,431
2022	1,450,117	3,567,008
2023	1,733,062	3,849,953
2024	2,016,724	4,133,615
2025	2,296,783	4,413,674
2026	2,572,161	4,689,052
2027	2,842,447	4,959,338
2028	3,108,222	5,225,113
2029	3,368,994	5,485,885
2030	3,627,734	5,744,626
2031	3,887,228	6,004,119
2032	4,147,898	6,264,789
2033	4,409,638	6,526,529

The MWh totals included in the table 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 projected summer and winter peak MW load impacts of all current and projected DEP DSM programs.

Projected MW Load Impacts of DSM Programs

Year	Summer Peak MW Reduction					
	EnergyWise Home	CIG Demand Response	DSDR	Large Load Curtailable	EnergyWise for Business	Total Summer Peak
2018	367	27	211	284	5	894
2019	383	32	213	287	9	923
2020	400	39	215	290	14	958
2021	411	46	215	292	19	984
2022	417	54	217	295	24	1,007
2023	417	57	218	298	29	1,019
2024	418	57	221	300	29	1,024
2025	418	57	224	300	29	1,027
2026	419	57	228	300	29	1,032
2027	419	57	231	300	29	1,035
2028	420	57	236	300	29	1,041
2029	420	57	238	300	29	1,044
2030	421	57	241	300	29	1,047
2031	421	57	244	300	29	1,051
2032	422	57	248	300	29	1,055
2033	422	57	250	300	29	1,058

Note: For DSM programs, Gross and Net are the same.

Projected MW Load Impacts of DSM Programs

	Winter Peak MW Reduction					
Year	EnergyWise Home	CIG Demand Response	DSDR	Large Load Curtailable	EnergyWise for Business	Total Winter Peak
2018	13	11	211	241	1	478
2019	15	15	213	246	1	490
2020	16	19	215	249	2	501
2021	18	23	215	251	3	511
2022	19	27	217	254	4	521
2023	20	31	218	256	5	530
2024	21	31	221	259	5	537
2025	23	31	224	259	5	541
2026	24	31	228	259	5	546
2027	25	31	231	259	5	550
2028	26	31	236	259	5	557
2029	28	31	238	259	5	560
2030	29	31	241	259	5	564
2031	30	31	244	259	5	569
2032	31	31	248	259	5	574
2033	33	31	250	259	5	578

Note: For DSM programs, Gross and Net are the same.

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.

Programs Evaluated but Rejected:

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

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.

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 energy audits.

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.

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.

APPENDIX E: FUEL SUPPLY

Duke Energy Progress' current fuel usage consists of a mix of coal, natural gas and uranium. Oil is used for peaking generation and natural gas continues to play an increasing role in the fuel mix due to lower pricing and the addition of a significant amount of combined cycle generation. A brief overview and issues pertaining to each fuel type are discussed below.

Natural Gas:

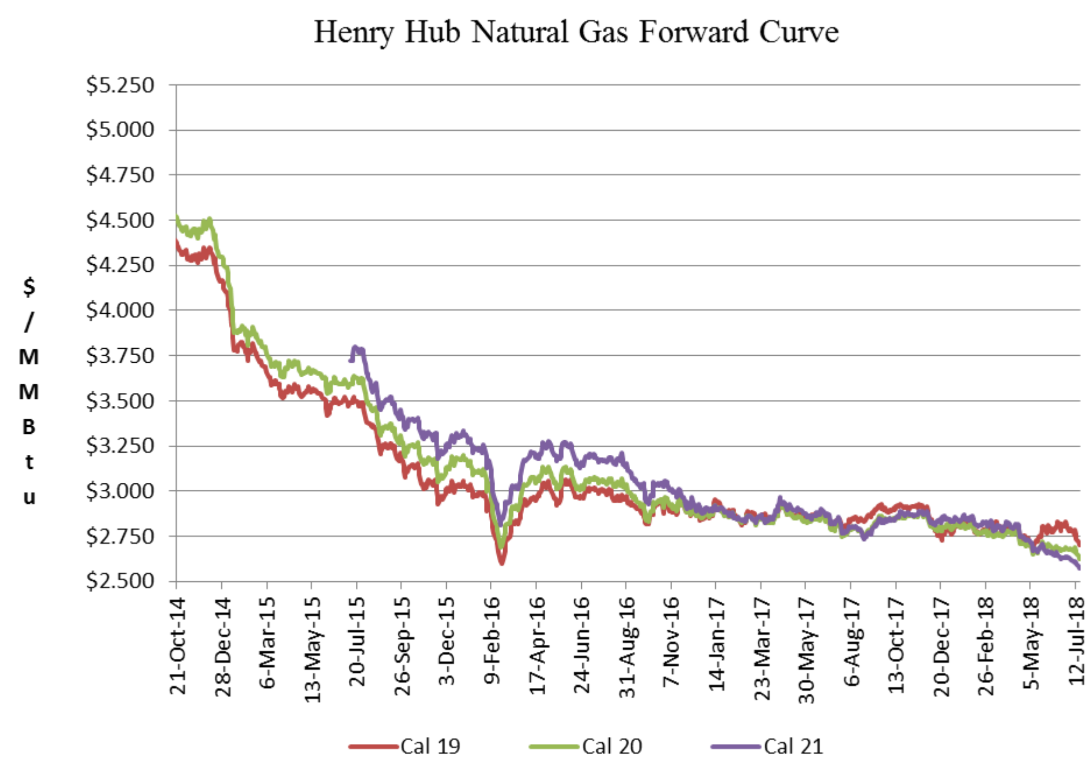
During 2017 NYMEX Henry Hub natural gas prices averaged approximately $3.10 per million BTU (MMBtu) and U.S. lower-48 net dry production averaged approximately 73 billion cubic feet per day (BCF/day). Natural gas spot prices at the Henry Hub averaged approximately $3.71 per MMBtu in January 2018. Henry Hub spot pricing decreased throughout the remaining winter months and averaged $2.65 per MMBtu at the end of March 2018 The lower short-term spot prices in February and March 2018 were driven by both fundamental supply and demand factors.

Average daily U.S. net dry production levels of approximately 76.7 BCF/day in the first quarter of 2018 were 5.4BCF/day higher than the comparable period in 2017. Storage ended the winter withdrawal season at approximately 1.4 trillion cubic feet (TCF) as of March 31, 2018. Lower-48 U.S. overall demand in the first quarter of 2018 was higher than normal due to the cold winter weather which raised residential heating needs and resulted in gas storage withdrawals through late April 2018.

Summer 2018 spot natural gas prices have decreased from the end of January 2018 prices that were in the low $3.60's per MMBtu. The Henry Hub spot price settled in a range between approximately $2.74 to $2.90 per MMBtu in mid-July 2018. Working gas in storage remains below the 5-year average and storage balances from a year ago, however, market prices have declined over the last few months with expectations of continued record supply of dry gas production approaching 81.3 Bcf/d forecasted by the latest July 2018 EIA short term gas outlook. Observed average NYMEX Henry Hub prices for the winter period November 2018 through March 2019 have decreased to approximately $2.90 per MMBtu from the prices observed in late March 2018. Although predicting actual storage balances at the end of the typical injection season is not possible, current projections are roughly 3.4 to 3.5 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 2018 increasing 2.4 Bcf/d from 2017 levels, due primarily to increases in electric power usage. Per the EIA's short-term energy outlook released on July 10, 2018, this year also reflects higher residential and commercial demand because the first quarter of 2018 was colder than the first quarter of 2017. EIA expects the share of U.S. total utility-scale electricity generation from natural gas-fired power plants to rise from 32% in 2017 to 34% in 2018 and 35% in 2019. As a result, coal's forecast share of electricity generation falls from 30% in 2017 to 28% in 2018 and to 27% in 2019. The EIA estimates that total natural gas production will average 81.3Bcf/d in 2018, which will establish a new record. EIA also expects natural gas production will rise an additional 3.1 Bcf/d in 2019 to 84.5 Bcf/d. 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 20, 2018, the U.S. Natural Gas rig count was at 187. This is flat from last year at the same time and up from all time low rig count of 81 in August of 2016.

In addition to the trends in shorter term natural gas spot price levels for 2018, in late February 2018, the observed forward market prices for the periods of 2019 through 2021 averaged approximately $2.77 per MMBtu. During this period, the forward price curve is relatively flat reflecting an expectation of balanced supply and demand fundamentals. Prices have decreased in the last few months to approximately $2.64 per MMBtu as of late July 2018. This is illustrated in the figure below.



Looking forward, the forward 5 and 10-year observable market curves are at $2.61 and $2.73 per MMBtu, respectively, as of the July 20, 2018 close. In addition, as of the close of business on July 21, 2018, the one (1), three (3) and five (5) years strips were all approximately $2.63 per MMBtu. As illustrated with these price levels and relationships, the forward NYMEX Henry Hub price curve is extremely flat with the periods of 2020 and 2021 currently trading at discounts to 2019 prices. The gas market is expected to remain relatively stable due to an improving economic picture which may allow supply and demand to further come into balance. Demand for natural gas from the power sector for 2018 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 through the 2020 timeframe. The long-term fundamental gas price outlook continues to be little changed from the 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 97% of net natural gas production today, which has increased from approximately 38% in 2014. As noted earlier, per the Short-Term EIA outlook dated July 10, 2018, the EIA expects dry gas production to average 81.3 Bcf/d by the end of 2018 and rise by an additional 3.1 Bcf/d in 2019 to 84.5 Bcf/d. The United States was a net exporter of natural gas in the first quarter of 2018, with net exports averaging 0.5 Bcf/d. Rising LNG exports and pipeline exports have contributed to a shift from being a net importer of natural gas to an exporter. According to the EIA forecast, the US should have a total liquefaction capacity of 9.6 Bcf/d by the end of 2020.

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 forward natural gas prices have continued to decline and there has been 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.

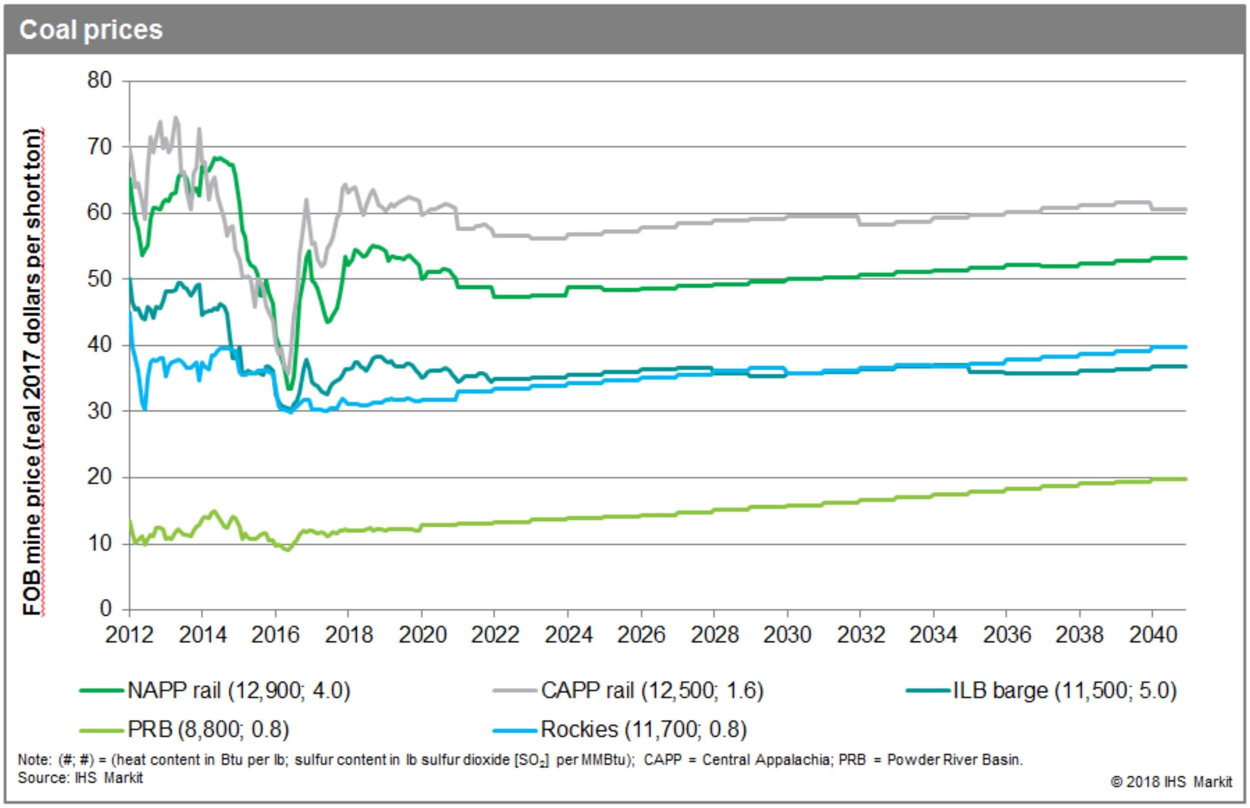
In order to ensure adequate natural gas supplies, transportation and storage, the company has gas procurement strategies that include periodic RFPs, market solicitations, and short-term market engagement activities to procure a reliable, flexible, diverse, and competitively priced natural gas supply and transportation portfolio that supports DEP's CC and CT 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 as 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:

The main determinants for power sector coal demand are electricity demand growth and non-coal electric generation, namely nuclear, gas, hydro and renewables. With electricity demand growth remaining very low, continued steady nuclear and hydro generation, and increasing gas-fired and renewable generation, coal-fired generation continues to be the marginal fuel experiencing declines. According to the EIA, electric power sector demand has been steadily dropping and accounted for 665 million tons (86%) of total demand for coal in 2017. Additionally, projections show continued strong supply and low prices for natural gas which continues to result in reduced, but more volatile, coal burns. Increasing renewable generation, particularly in North Carolina, is also contributing to increased volatility for coal generation.

Coal markets continue to be impacted by a number of factors, including: (1) uncertainty around proposed, imposed, and stayed U.S. Environmental Protection Agency (EPA) regulations for power plants; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices, which has reduced overall coal demand; (3) continued changes in global market demand for both steam and metallurgical coal; (4) uncertainty surrounding regulations for mining operations; and (5) tightening supply as bankruptcies, consolidations and company reorganizations have allowed coal suppliers to restructure and settle into new, lower on-going production levels.

According to IHS Markit, future coal prices for the CAPP, NAPP and ILB coals are expected to be in a steady downward trend until 2022 when they flatten and begin to modestly and steadily rise. Future pricing for Western coals are expected to be steadily rising for the next 20 years.



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 fundamental outlook anticipates the eventual implementation of carbon legislation in some form beginning in 2022 which makes coal capacity less desirable, resulting in a long-term decline in power generation from coal. IHS Markit expects 34 GW of coal plant retirements from 2017 to 2020 – with 16.6 GW in 2018 alone, followed by 44 GW from 2021 to 2025, and 23 GW from 2026 to 2030.

One bright spot is that coal exports are at historically high levels (low 100 million tons range) which has provided some support for coal producers, but margins have been eroded by increased ocean freight costs and more volatile index pricing. IHS Markit expects US exports to remain strong, and there is additional potential upside if supply does truly tighten. A key to US export growth is low-cost but high-sulfur coal. Certain key markets (primarily India and Europe) have become accustomed to the high sulfur, and the low production costs for efficient long-wall production of these types of coals enables it to compete very well. In addition to the upside from India, Turkey now appears likely to increase the maximum sulfur allowed in its coal plants. This is bullish for NAPP and ILB exports.

The Company continues to maintain a comprehensive coal procurement strategy that has proven successful over the years in limiting average annual fuel price changes while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost-effective manner. Aspects of this procurement strategy include having an appropriate mix of contract and spot purchases for coal, staggering coal contract expirations which thereby limit exposure to market price changes, diversifying coal sourcing as economics warrant, as well as working with coal suppliers to incorporate additional flexibility into their supply contracts. In response to the unpredictable and volatile nature of the demand for coal, the Company has implemented more frequent procurement practices. However, coal inventory levels have dropped and recent experience has shown that producers and transporters of coal are experiencing significant challenges with responding to 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.

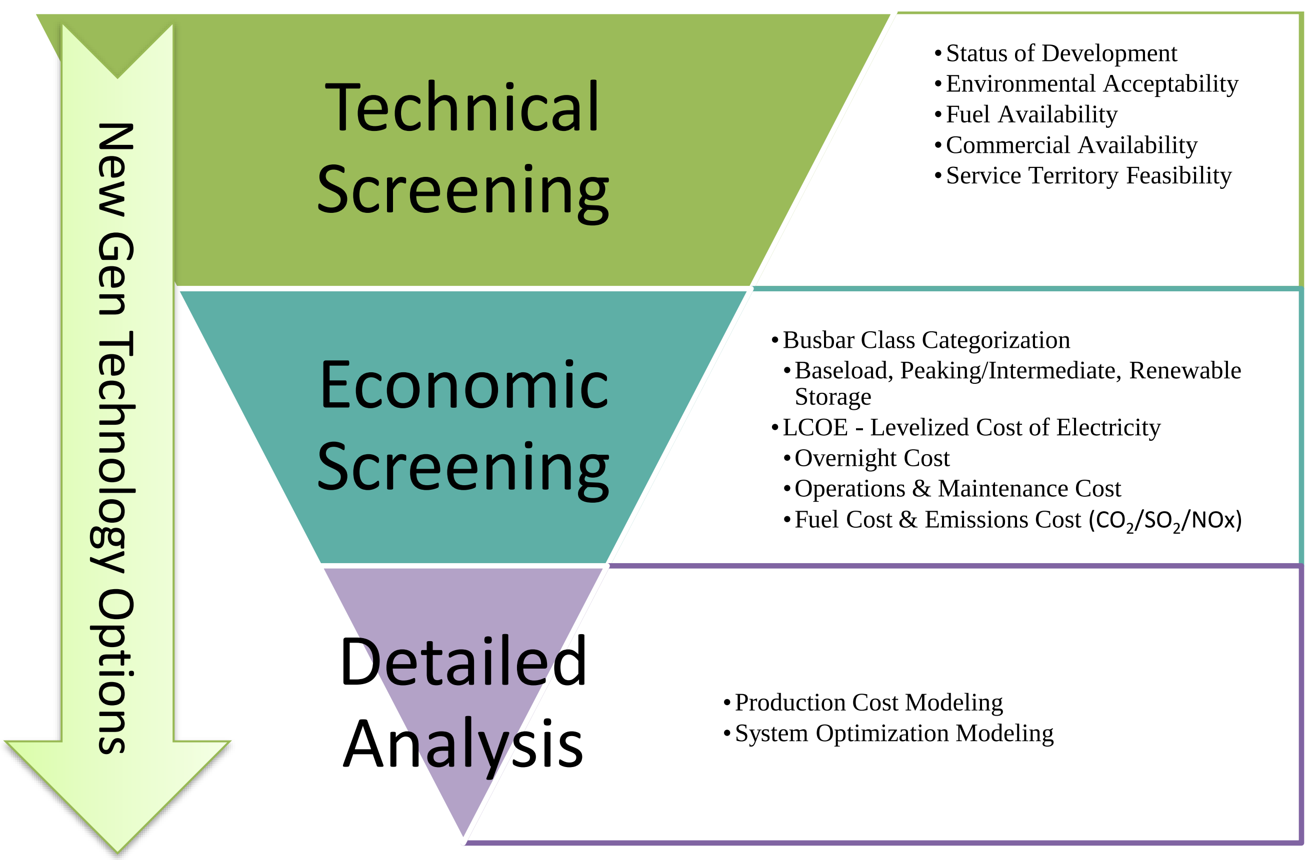
As fuel with a low cost basis is used and lower-priced legacy contracts are replaced with contracts at higher market prices, nuclear fuel expense is expected to increase in the future. Although the costs of certain components of nuclear fuel are expected to increase in future years, nuclear fuel costs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

Figure F-1: New Generation Technologies Screening Process

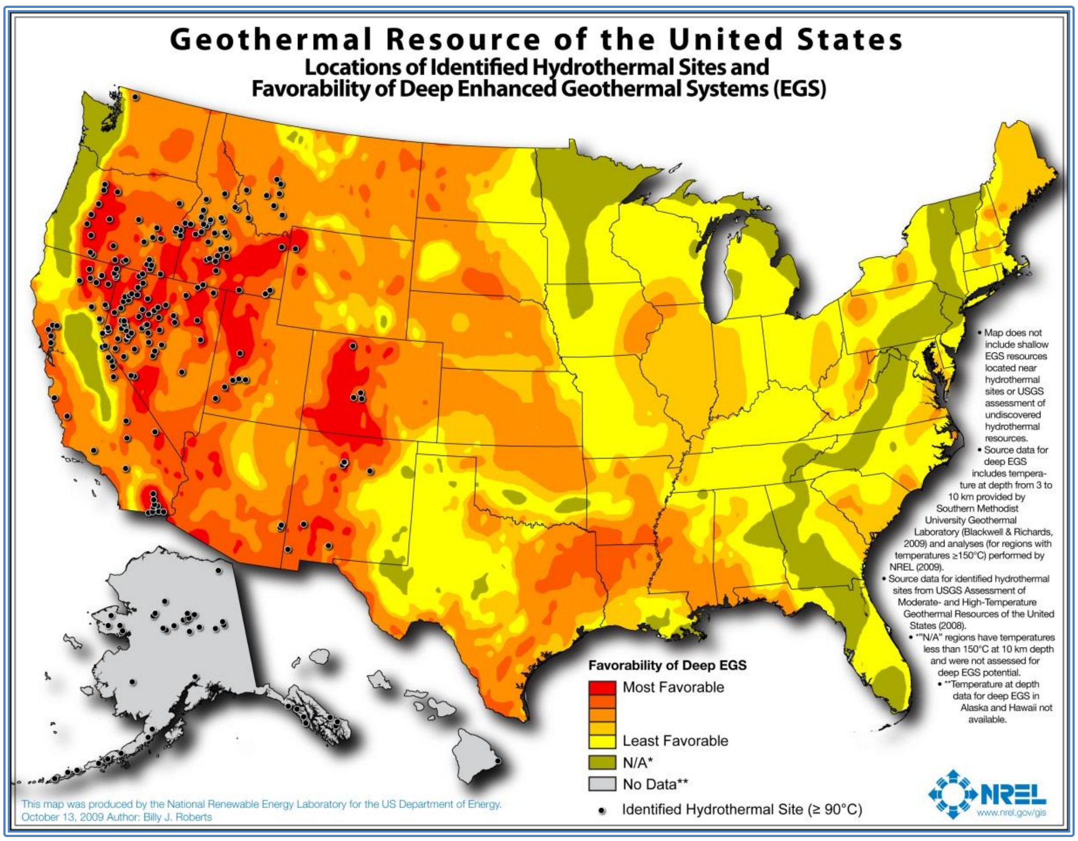


Technical Screening:

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. See Figure F-2, below.

Figure F-2: NREL Geothermal Resource Map of the US.

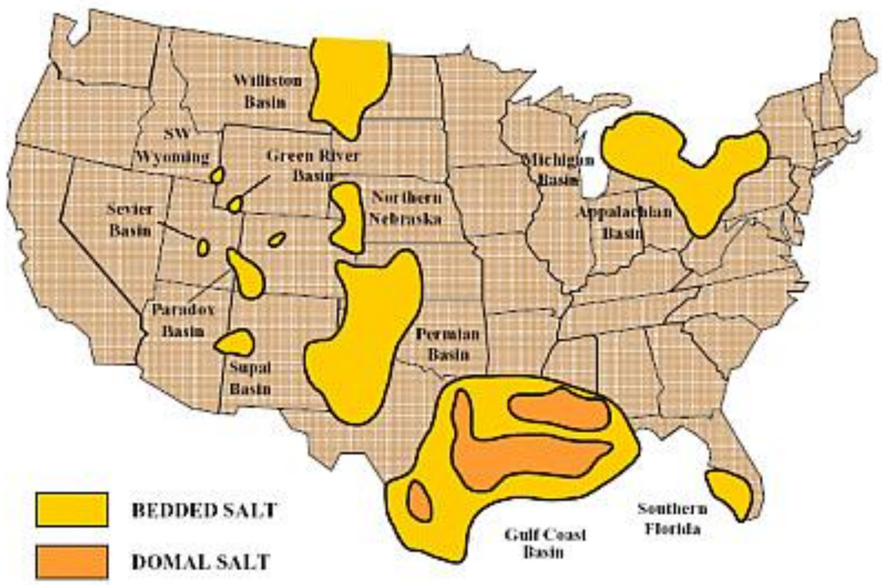


> **Pumped Storage Hydropower (PSH)** is the only conventional, mature, commercial, utility-scale electricity storage option available currently. This technology consumes off-peak electricity by pumping water from a lower reservoir to an upper reservoir.

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% (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, Bad Creek Reservoir and Jocassee Hydro with an approximate combined generating capacity of 2,140 MW.

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 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 – 20 MW. 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.

Figure F-3: Compressed Air Energy Storage (CAES) - Potential U.S. Salt Cavern Site Depiction, NETL.



Liquid Air Energy Storage (LAES) uses electricity to cool air until it liquefies, stores the liquid air in a tank, brings the liquid air back to a gaseous state (by exposure to ambient air or with waste heat from an industrial process) and uses that gas to turn a turbine and generate electricity. Although demonstrated through several pilot projects, the scaling of this technology and the resultant economics is not yet completely understood. As research and pilots continues with LAES, Duke Energy will continue to monitor as the technology offers bulk energy storage without the need for reservoir construction.

Small Modular Nuclear Reactors (SMR) are generally defined as having capabilities of less than 300 MW per reactor. They typically have the capability of grouping a number of reactors in the same location to achieve the desired power generating capacity for a plant. 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 continue to gain interest as they contribute no emissions to the atmosphere and, unlike their predecessors, provide flexible operations capabilities, as well as, reduced footprints coupled with inherently safer designs.

NuScale Power is the leader in SMR design and licensing in the US. They recently announced that its small modular reactor will be able to generate 20% more power than originally planned. The increase is from 50 MW to 60 MW for each module (reactor) or 600 MW to 720 MW for a 12-module plant. The increase requires very little additional capital cost so it lowers the projected cost of a 12-module facility by approximately 16% per kilowatt. The approval date for the SMR Design Certification Application (DCA) is September 2020. NuScale will need NRC approval of a revised DCA before SMR customers will be able to take advantage of the additional power.

Other SMR designs under development domestically include the Holtec SMR-160, a 160 MW pressurized water reactor being developed for deployment both in the U.S. and abroad. In addition, GE Hitachi (GEH) recently announced the development of a new SMR, the BWRX300.

While SMRs were "screened out" in the Technical Screening phase of the technology evaluations, they were allowed to be selected as a resource in the System Optimizer (SO) model in order to allow the model to meet the high CO_2 emission constraints in the sensitivity analysis. As a result, SMRs have been depicted on the busbar screening curves as an informative item. 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.

Advanced Reactors are typically defined as nuclear power reactors employing fuel and/or coolant significantly different from that of current light water reactors (LWRs) and offering advantages related to safety, cost, proliferation resistance, waste management and/or fuel utilization. These reactors are characteristically typed by coolant with the main groups including liquid metal cooled, gas cooled, and molten salt fueled/cooled. There are approximately 25 domestic companies working on one or multiple advanced reactor designs funded primarily by venture capital investment, and even more designs are being considered at universities and national labs across the country. There is also significant interest internationally, with at least as many international companies pursuing their own advanced reactor designs in several countries across the world.

Specifics of the reactor vary significantly by both coolant type and individual designs. The reactors are projected to range in size from the single MW scale to over 1000 MW, with the majority of the designs proposing a modular approach that can scale capacity based on demands. All designs are exploring a flexible deployment approach which could scale power outputs to align with renewable/variable outputs. The first commercially available advanced reactors are targeting the late 2020s for deployment, although most designs are projected to be available in the 2030s. Significant legislative efforts are currently being made to further the development of advanced reactors in both the house and senate at the national level, and new bills continue to be introduced.

Duke Energy has been part of an overall industry effort to further the development of advanced reactors since joining the Nuclear Energy Institute Advanced Reactor Working Group at its formation in early 2015. Additionally, Duke Energy participates on two Advanced Reactor companies' industry boards and has hosted several reactor developers for early design discussions. Duke Energy has also participated in several other industry efforts such as EPRI's Owner-Operator Requirements Document, which outlines requirements and recommendations for Advanced Reactor designs. Duke Energy will continue to allot resources to follow the progress of the advanced reactor community and will provide input to the proper internal constituents as additional information becomes available.

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. See Chapter 5 for more information regarding current and planned Duke Energy poultry and swine waste projects.

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 although that trend may be changing. This technology remains expensive even with the five-year tax credit extension granted in December 2015. There are over twenty-five projects in various phases of development in U.S. coastal waters and more are anticipated as technology and construction advancements allow for installation in deeper waters further offshore. The Block Island project developed by Deepwater Wind is the first to reach commercial operation, and Duke Energy Renewables is performing remote monitoring and control services for the project. This 30 MW project is located about 3 miles off the coast of Rhode Island.

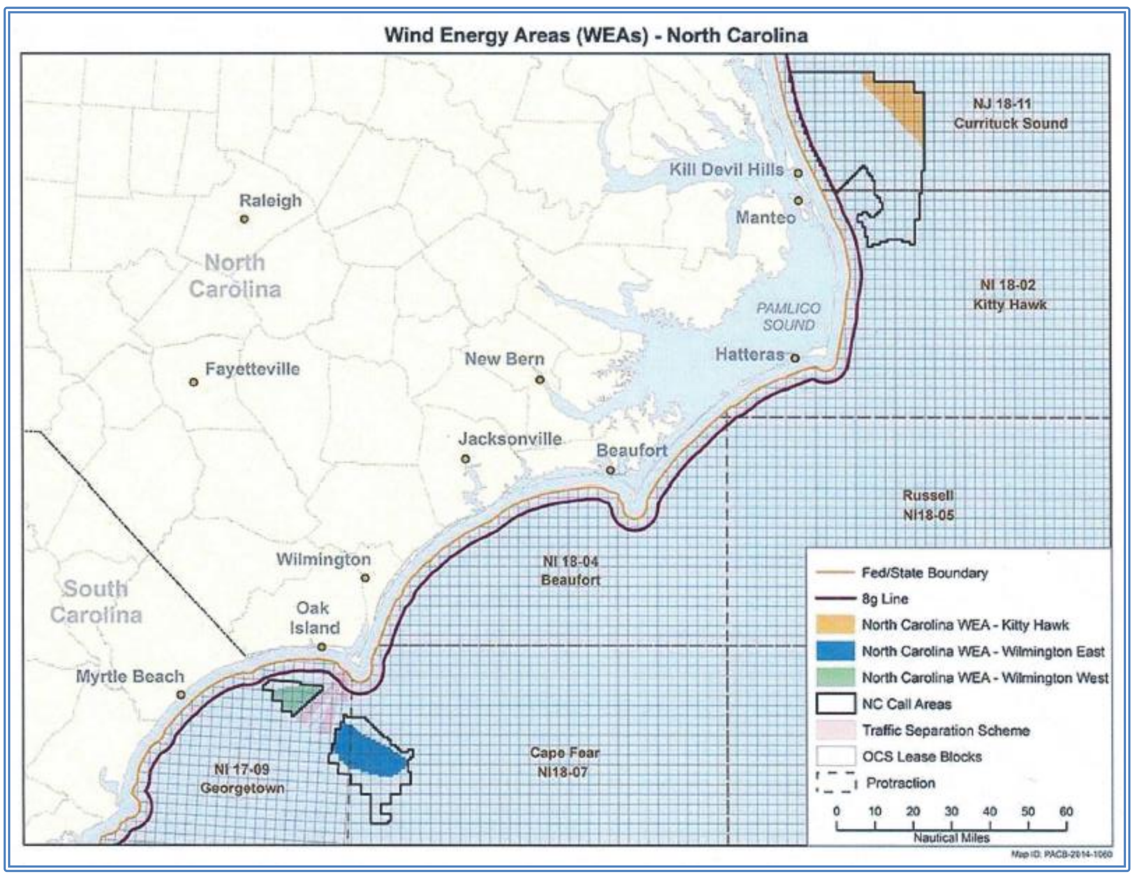
Duke Energy and NREL studied the potential for offshore integration off the coast of the Carolinas in March 2013. In 2015, the U.S. Bureau of Ocean Energy Management (BOEM) completed environmental assessments at three potential Outer Continental Shelf (OCS) sites off the coast of North Carolina. In March 2017, BOEM administered a competitive lease auction for wind energy in federal waters and awarded Avangrid Renewables the rights to develop an area off the shores of Kitty Hawk. Avangrid has plans for a project that may be as large as 1,500 MW.

Several coastal states including New York, New Jersey, Maryland, Massachusetts, California, and Hawaii are facilitating industry growth. New York has an Offshore Wind Master Plan aimed at 2,400 MW of offshore projects by 2030, and Statoil is developing the 1,500 MW Empire Wind project near New York City, aiming for completion in 2025.

The unique constraints of the industry and the increasingly competitive global market are driving R&D improvements that allow wind farms to be sited further offshore. Installation and siting require careful consideration to bathymetry and offshore construction concerns, but siting is further complicated by shipping lanes, fishing rights, wildlife migration patterns, military operations, and other environmental concerns. Plus, coastal residents and tourists prefer an unobstructed ocean view, so the larger turbines require longer distances to keep them out of sight.

Industry leaders are working to define equipment and installation standards and codes. They are coordinating with the oil and gas industry to improve construction processes and working with the telecommunications industry to advance submarine cable technologies. Improved foundation designs are helping to reduce installation time and costs, and floating designs are being tested for deployment in deep waters.

Figure F-4: NC Wind Energy Areas (WEAs) (developed in joint venture by Duke Energy and NREL)



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.

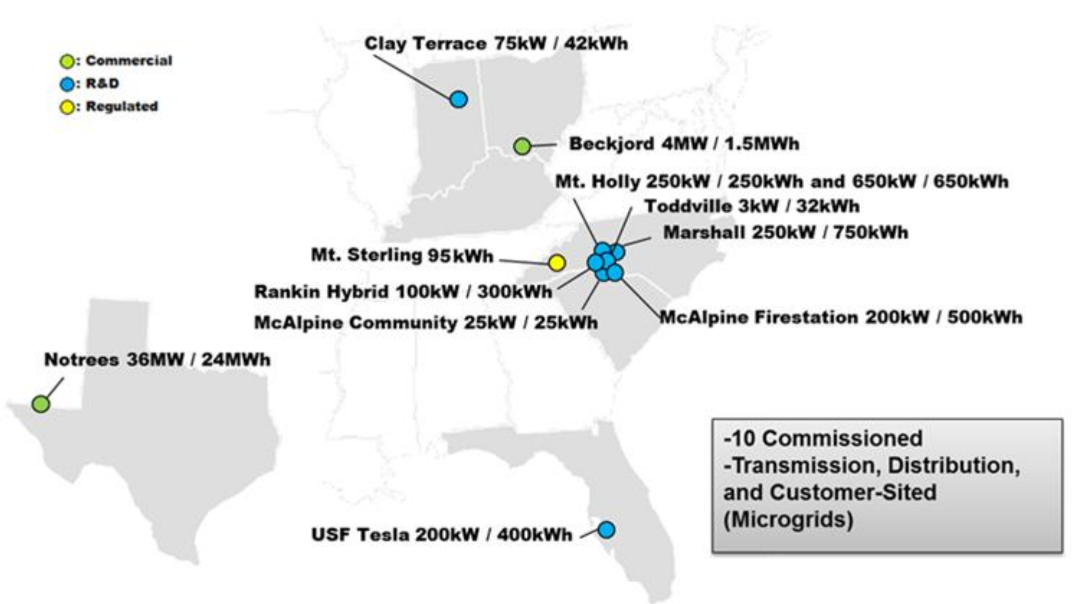
A brief explanation of the technology additions for 2018 and the basis for their inclusion follows:

Addition of Battery Storage Options to the IRP:

Energy storage solutions are becoming a viable tool 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 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). In order to generically evaluate the potential value of a generation-connected battery storage system an unencumbered battery dedicated to capacity and energy services will be utilized for screening purposes. *Encumbrances* to the battery are other uses which may limit, or even eliminate the battery system's ability to provide capacity and energy storage services. These encumbrances may include (but are not limited to) frequency response, asset deferral, back-up power, black start, ancillary services, etc. Duke Energy recognizes the potential benefits that battery connected systems can provide, especially at the Transmission & Distribution level which resides outside the scope of this IRP. Evaluation of potential T&D benefits, along with other uses that can be "stacked" with these T&D benefits, are being assessed on a case-by-case basis at this time through pilot projects.

Duke Energy has several projects in operation since 2011, mainly in support of regulating output voltages/frequencies from renewable energy sources to the grid. Each of these applications supports frequency regulation, solar smoothing, or energy shifting from a local solar array. See Figure F-5, below for a depiction of the existing, operational battery energy storage assets.

Figure F-5: Existing, Operational Duke Energy Battery Storage Assets



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.

Battery Briefing:

Electrochemical energy storage systems utilize chemical reactions within a battery cell to facilitate electron flow, converting electrical energy to chemical energy when charging and generating an electric current when discharged. Electrochemical technology is continually developing as one of the leading energy storage and load following technologies due to its modularity, ease of installation and operation, and relative design maturity. Development of electrochemical batteries has shifted into three categories, commonly termed "flow," "conventional," and "high temperature" battery designs. Each battery type has unique features yielding specific advantages compared to one another.

A **conventional battery** contains a cathodic and an anodic electrode and an electrolyte sealed within a cell container than can be connected in series to increase overall facility storage and output. During charging, the electrolyte is ionized such that when discharged, a reduction-oxidation reaction occurs, which forces electrons to migrate from the anode to the cathode thereby generating electric current. Batteries are designated by the electro-chemicals utilized within the cell; the most popular conventional batteries are lead acid and lithium ion type batteries.

Lead acid batteries are the most mature and commercially accessible battery technology, as their design has undergone considerable development since conceptualized in the late 1800s. The Department of Energy (DOE) estimates there is approximately 110 MW of lead acid battery storage currently installed worldwide. Although lead acid batteries require relatively low capital cost, this technology also has inherently high maintenance costs and handling issues associated with toxicity, as well as low energy density (yields higher land and civil work requirements). Lead acid batteries also have a relatively short life cycle at 5 to 10 years, especially when used in high cycling applications.

Lithium ion (Li-ion) batteries contain graphite and metal-oxide electrodes and lithium ions dissolved within an organic electrolyte. The movement of lithium ions during cell charge and discharge generates current. Li-ion technology has seen a resurgence of development in recent years due to its high energy density, low self-discharge, and cycling tolerance. Many Li-ion manufacturers currently offer 15-year warranties or performance guarantees. Consequently, Li- ion has gained traction in several markets including the utility and automotive industries.

Li-ion battery prices are trending downward, and continued development and investment by manufacturers are expected to further reduce production costs. While there is still a wide range of project cost expectations due to market uncertainty, Li-ion batteries are anticipated to expand their reach in the utility market sector. At present, Li-ion Battery Technology is the only battery technology considered for the 2018 IRP.

Flow batteries utilize an electrode cell stack with externally stored electrolyte material. The flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane, in which the charge-inducing chemical reaction occurs, and liquid electrolyte storage tanks, which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system in which the cells can be stacked in series to achieve the desired voltage difference.

The battery is charged as the liquid electrolytes are pumped through the electrode cell stacks, which serve only as a catalyst and transport medium to the ion-inducing chemical reaction. The excess positive ions at the anode are allowed through the ion-selective membrane to maintain electroneutrality at the cathode, which experiences a buildup of negative ions. The charged electrolyte solution is circulated back to storage tanks until the process is allowed to repeat in reverse for discharge as necessary.

In addition to external electrolyte storage, flow batteries differ from traditional batteries in that energy conversion occurs as a direct result of the reduction-oxidation reactions occurring in the electrolyte solution itself. The electrode is not a component of the electrochemical fuel and does not participate in the chemical reaction. Therefore, the electrodes are not subject to the same deterioration that depletes electrical performance of traditional batteries, resulting in high cycling life of the flow battery. Flow batteries are also scalable such that energy storage capacity is determined by the size of the electrolyte storage tanks, allowing the system to approach its theoretical energy density. Flow batteries are typically less capital intensive than some conventional batteries but require additional installation and operation costs associated with balance of plant equipment.

High temperature batteries operate similarly to conventional batteries, but they utilize molten salt electrodes and carry the added advantage that high temperature operation can yield heat for other applications simultaneously. The technology is considered mature with ongoing commercial development at the grid level. The most popular and technically developed high temperature option is the Sodium Sulfur (NaS) battery. Japan-based NGK Insulators, the largest NaS battery manufacturer, installed a 4 MW system in Presidio, Texas in 2010 following operation of systems totaling more than 160 MW since the project's inception in the 1980s.

The NaS battery is typically a hermetically sealed cell that consists of a molten sulfur electrolyte at the cathode and molten sodium electrolyte at the anode, separated by a Beta-alumina ceramic membrane and enclosed in an aluminum casing. The membrane is selectively permeable only to positive sodium ions, which are created from the oxidation of sodium metal and pass through to combine with sulfur resulting in the formation of sodium polysulfides. As power is supplied to the battery in charging, the sodium ions are dissociated from the polysulfides and forced back through the membrane to re-form elemental sodium. The melting points of sodium and sulfur are approximately 98 ^{o}C and 113 ^{o}C, respectively. To maintain the electrolytes in liquid form and for optimal performance, the NaS battery systems are typically operated and stored at around 300 ^{o}C, which results in a higher self-discharge rate of 14 percent to 18 percent. For this reason, these systems are usually designed for use in high-cycling applications and longer discharge durations.

NaS systems are expected to have an operable life of around 15 years and are one of the most developed chemical energy storage technologies. However, unlike other battery types, costs of NaS systems have historically held, making other options more commercially viable at present.

Generation Flexibility:

As more intermittent generation becomes associated with Duke's system, the greater need there may be for generation that has rapid load shifting and ancillary support capabilities. This generation would need to be dispatchable, possess desirable capacity, and ramp at a desired rate. Some of the technologies that have 'technically' screened in possess these qualities or may do so in the near future. Effort is being made to value the characteristics of flexibility and quantify that value to the system. As a result of the flexible generation need, some features of 'generic' plant's base designs have been modified to reflect the change in cost and performance to accomplish a more desired plant characteristic to diminish the impact of the intermittent generation additions.

Economic Screening:

The Company screens all technologies using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves, also referred to as *busbar* curves. The *Busbar* curve estimates the revenue requirement (i.e. life-cycle cost) of power from a supply option at the "busbar," the point at which electricity leaves the plant (i.e. the high side of the step-up transformer). Duke Energy provides some additional evaluation of a generic transmission and/or interconnection cost adder associated with each technology.

The screening within each general class of busbar (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. For the 2018 IRP year, Duke Energy has provided an additional busbar to represent Storage technology comparisons. As Storage technologies are not traditional generating resource options, they should be compared independently from generating resources. In addition, there has been no *charging* cost associated with the storage busbar buildup. This charging cost is excluded as it is dependent upon what the next marginal unit is in the dispatch stack as to what would be utilized to "charge" the storage resource. For resource options inclusive of or coupled with storage, it is assumed that the storage resource is being directly charged by the generating resource (i.e. Solar PV plus Battery Storage option).

This screening (busbar) 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. 2018 additions include Solar PV plus Battery Storage, additional Lithium ion Battery Storage options, and Pumped Storage Hydro as a renewable technology.

Dispatchable (Winter Ratings)

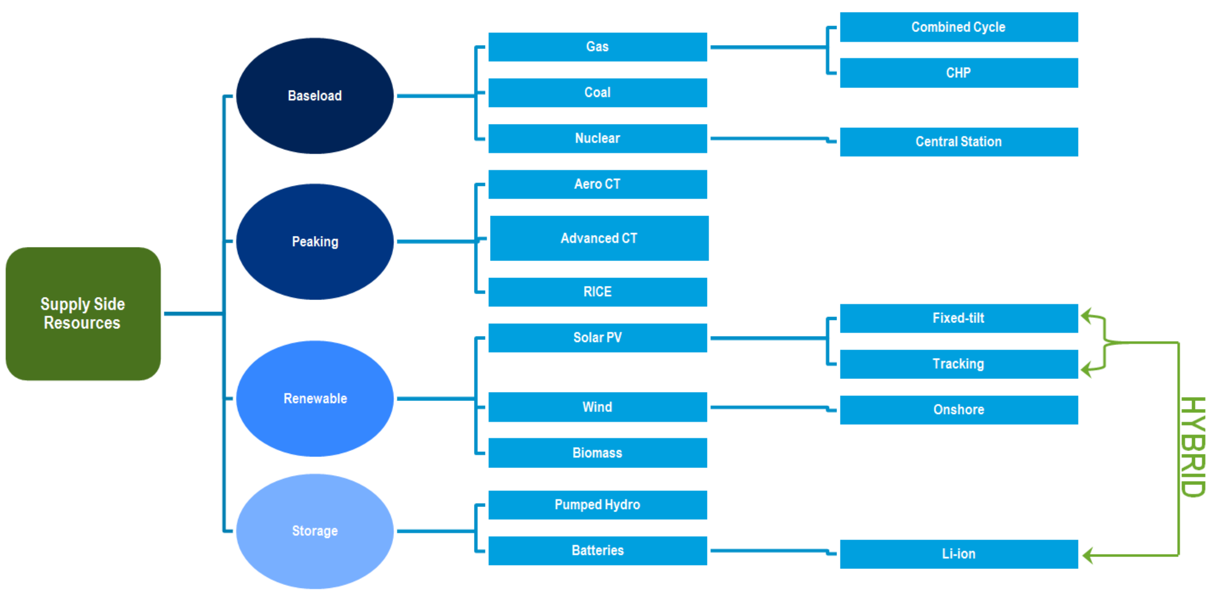
- Base load – 782 MW Ultra-Supercritical Pulverized Coal with CCS
- Base load – 557 MW 2x1 IGCC with CCS
- Base load – 2 x 1,117 MW Nuclear Units (AP1000)
- Base load – 667 MW – 1x1x1 Advanced Combined Cycle (No Inlet Chiller and Fired)
- Base load – 1,339 MW – 2x2x1 Advanced Combined Cycle (No Inlet Chiller and Fired)
- Base load – 22 MW – Combined Heat & Power (Combustion Turbine)
- Base load – 9 MW – Combined Heat & Power (Reciprocating Engine)
- Base load – 600 MW – Small Modular Reactor (SMR)
- Peaking/Intermediate – 196 MW 4 x LM6000 Combustion Turbines (CTs)
- Peaking/Intermediate – 202 MW, 12 x Reciprocating Engine Plant
- Peaking/Intermediate – 574 MW 2 x G/H-Class Combustion Turbines (CTs)
- Peaking/Intermediate – 754 MW 2 x J-Class Combustion Turbines (CTs)
- Peaking/Intermediate – 919 MW 4 x 7FA.05 Combustion Turbines (CTs)

- Storage – 5 MW / 5 MWh Li-ion Battery
- Storage – 20 MW / 80 MWh Li-ion Battery
- Storage – 1,400 MW Pumped Storage Hydro (PSH)
- Renewable – 2 MW Solar PV plus 2 MW / 8 MWh Li-ion Battery
- Renewable – 75 MW Wood Bubbling Fluidized Bed (BFB, biomass)
- Renewable – 5 MW Landfill Gas

Non-Dispatchable (Nameplate)

- Renewable – 150 MW Wind - On-Shore
- Renewable – 50 MW Solar PV, Fixed-tilt (FT)
- Renewable – 50 MW Solar PV, Single Axis Tracking (SAT)

Figure F-6: Duke Energy, Screened-In Supply Side Resource Alternatives



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 (EPRI) Technical Assessment Guide (TAG®), and Energy Information Administration (EIA). In addition, fuel and operating cost estimates are developed internally by Duke Energy, or from other sources such as those mentioned above, or a combination of the two. EPRI information or other information or estimates from external studies are not site-specific, but generally reflect the costs and operating parameters for installation in the Carolinas. Finally, every effort is made to ensure that capital, operating and maintenance costs (O&M), fuel costs and other parameters are current and include similar scope across the technologies being screened. The supply-side screening analysis uses the same fuel prices for coal and natural gas, and NO_x, SO_2, and CO_2 allowance prices as those utilized downstream in the detailed analysis (discussed in Appendix A). Screening curves were developed for each technology to show the economics with and without carbon costs (i.e. No CO_2, With CO_2) in the four major categories defined (Baseload, Peaking/Intermediate, Renewable, Storage).

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 CO_2, With CO_2). Although CHP can be competitive with CC, it is site specific, requiring a local steam and electrical load. The baseload curves also show that projected SMR 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 in Duke Energy territories.

The peaking 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. Simple cycle aero-derivative gas turbines still remain in close contention with reciprocating engines. Should a need be identified for one of these two types of resources, a more in-depth analysis would be performed.

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 and biomass 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/energy. 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 and sustainability initiatives.

Centralized generation, as depicted above, will remain the backbone of the grid for Duke Energy in the near term; however, in addition it is likely that distributed generation and storage (see ISOP discussions) will begin to share more and more grid responsibilities over time as technologies such as energy storage increase our grid's flexibility and tolerance for intermittent, distributed resources.

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.

Capital Cost Forecast:

A capital cost forecast was developed with support from a third party to project not only Renewables and Battery Storage capital costs, but the costs of all resource technologies technically screened in. The Technology Forecast Factors were sourced from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2017 which provides costs projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS) utilized by the EIA for the AEO.

Using 2018 as a base year, an "annual forecast factor is calculated based on the macroeconomic variable tracking the metals and metal products producer price index, thereby creating a link between construction costs and commodity prices." (NEMS Model Documentation 2016, July 2017)

From *NEMS Model Documentation 2016, July 2017*:

"*Uncertainty about investment costs for new technologies is captured in the Electric Capacity Planning module of NEMS (ECP) using technological optimism and learning factors.*

- *The technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development. As development proceeds and more data become available, cost estimates become more accurate and the technological optimism factor declines.*

- *Learning factors represent reductions in capital costs due to learning-by-doing. Learning factors are calculated separately for each of the major design components of the technology. For new technologies, cost reductions due to learning also account for international experience in building generating capacity. Generally, overnight costs for new, untested components are assumed to decrease by a technology specific percentage for each doubling of capacity for the first three doublings, by 10% for each of the next five doublings of capacity, and by 1% for each further doubling of capacity. For mature components or conventional designs, costs decrease by 1% for each doubling of capacity.*"

The resulting Forecast Factor Table developed from the EIA technology maturity curves for each corresponding technology screened is depicted in Table F-1. A third-party vendor assisted in the alignment of the technologies screened to their representative forecast factors available from the EIA for technologies not captured by the EIA. Examples of this include Reciprocating Internal Combustion Engines (RICE), Battery Storage, and gas turbine technology configurations among others.

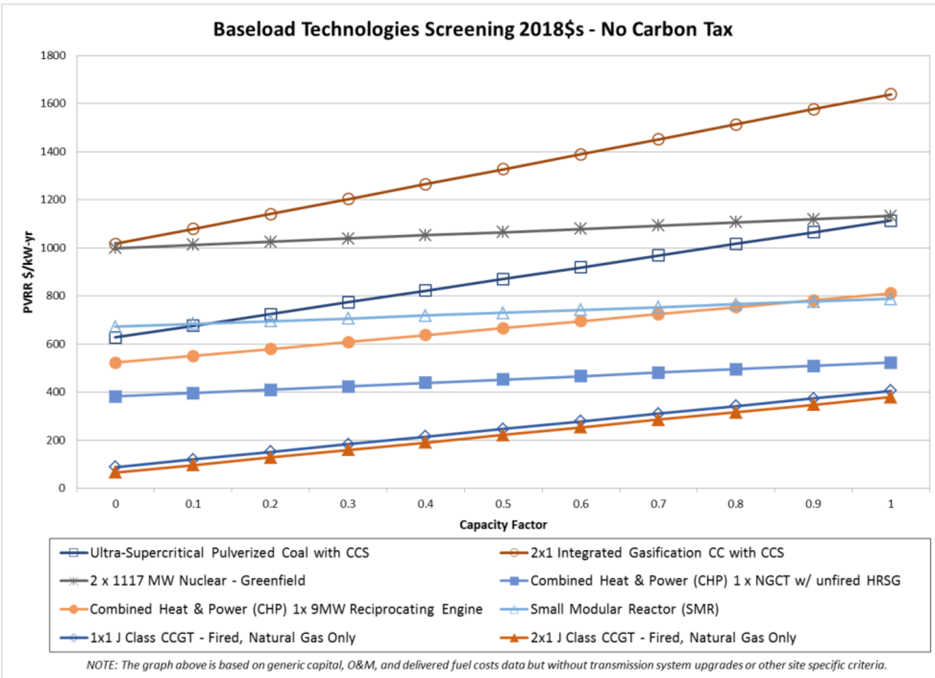
Table F-1: Snip from Forecast Factor Table by Technology (EIA - AEO 2017)

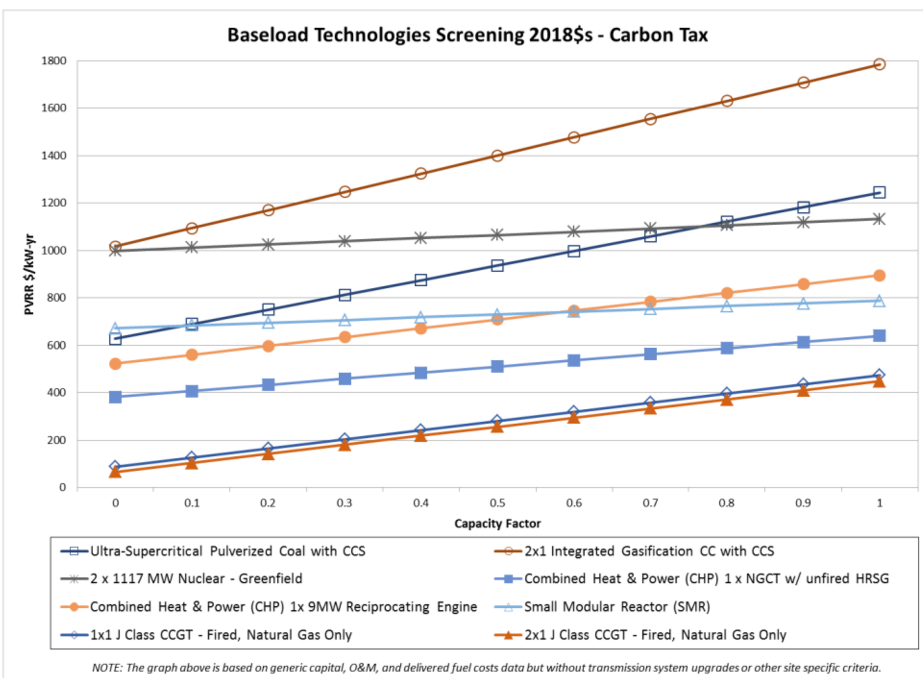
Year	Aero CT	F Class Frame CT	J Class Frame CT	RICE	Onshore Wind	1x1 J Class Combined Cycle	2x1 J Class Combined Cycle
2018	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2019	0.996	0.995	0.995	0.996	0.996	0.995	0.995
2020	0.993	0.990	0.990	0.993	0.993	0.991	0.990
2021	0.989	0.984	0.984	0.989	0.989	0.986	0.984
2022	0.983	0.978	0.978	0.983	0.983	0.980	0.978
2023	0.974	0.967	0.967	0.974	0.974	0.970	0.967
2024	0.965	0.957	0.957	0.965	0.965	0.960	0.957
2025	0.954	0.942	0.942	0.954	0.954	0.947	0.942
2026	0.941	0.920	0.920	0.941	0.941	0.928	0.920
2027	0.928	0.902	0.902	0.928	0.928	0.913	0.902
2028	0.918	0.877	0.877	0.918	0.918	0.894	0.877
2029	0.910	0.859	0.859	0.910	0.910	0.879	0.859
2030	0.901	0.840	0.840	0.901	0.901	0.864	0.840
2031	0.892	0.827	0.827	0.892	0.892	0.853	0.827
2032	0.884	0.815	0.815	0.884	0.884	0.842	0.815

These forecast factors were blended with additional third-party capital cost projections for more rapidly developing technologies (i.e. Solar PV, Battery Storage) in order to provide a consistent forecast through the planning period for all technologies evaluated.

Screening Curves:

The following pages contain the technology screening curves for baseload, peaking/intermediate, renewable and storage technologies.


Baseload Technologies Screening 2018$s - No Carbon Tax
PVRR $/kW-yr
0
200
400
600
800
1000
1200
1400
1600
1800
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Capacity Factor
Ultra-Supercritical Pulverized Coal with CCS
2x1 Integrated Gasification CC with CCS
2 x 1117 MW Nuclear - Greenfield
Combined Heat & Power (CHP) 1 x NGCT w/ unfired HRSG
Combined Heat & Power (CHP) 1x 9MW Reciprocating Engine
Small Modular Reactor (SMR)
1x1 J Class CCGT - Fired, Natural Gas Only
2x1 J Class CCGT - Fired, Natural Gas Only
NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.


Baseload Technologies Screening 2018$s - Carbon Tax
PVRR $/kW-yr
0
200
400
600
800
1000
1200
1400
1600
1800
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Capacity Factor
Ultra-Supercritical Pulverized Coal with CCS
2x1 Integrated Gasification CC with CCS
2 x 1117 MW Nuclear - Greenfield
Combined Heat & Power (CHP) 1 x NGCT w/ unfired HRSG
Combined Heat & Power (CHP) 1x 9MW Reciprocating Engine
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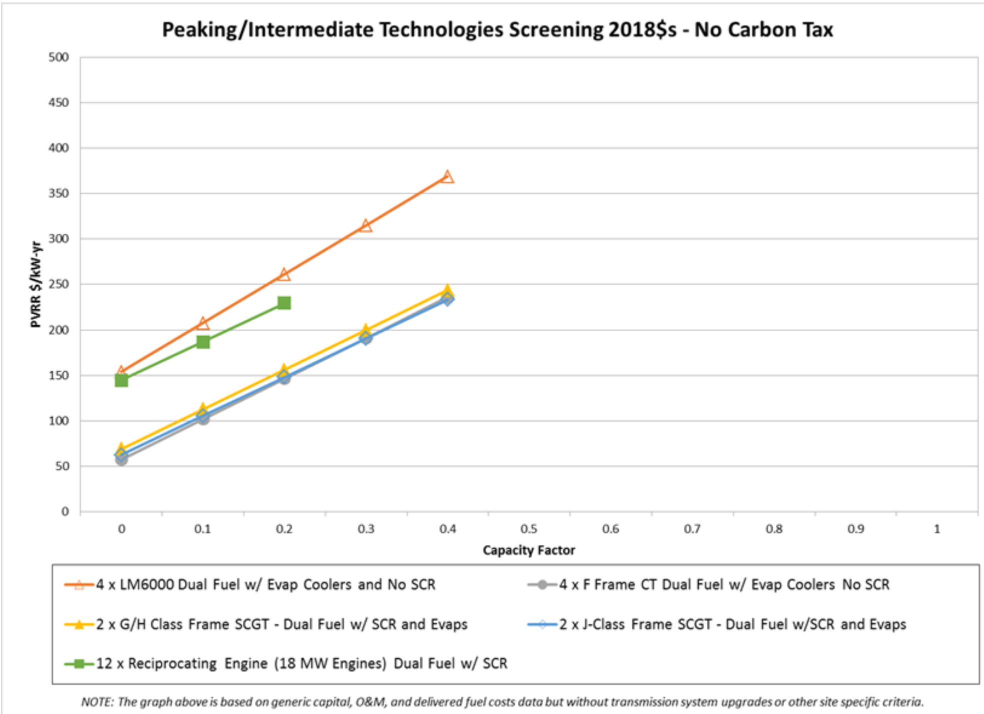
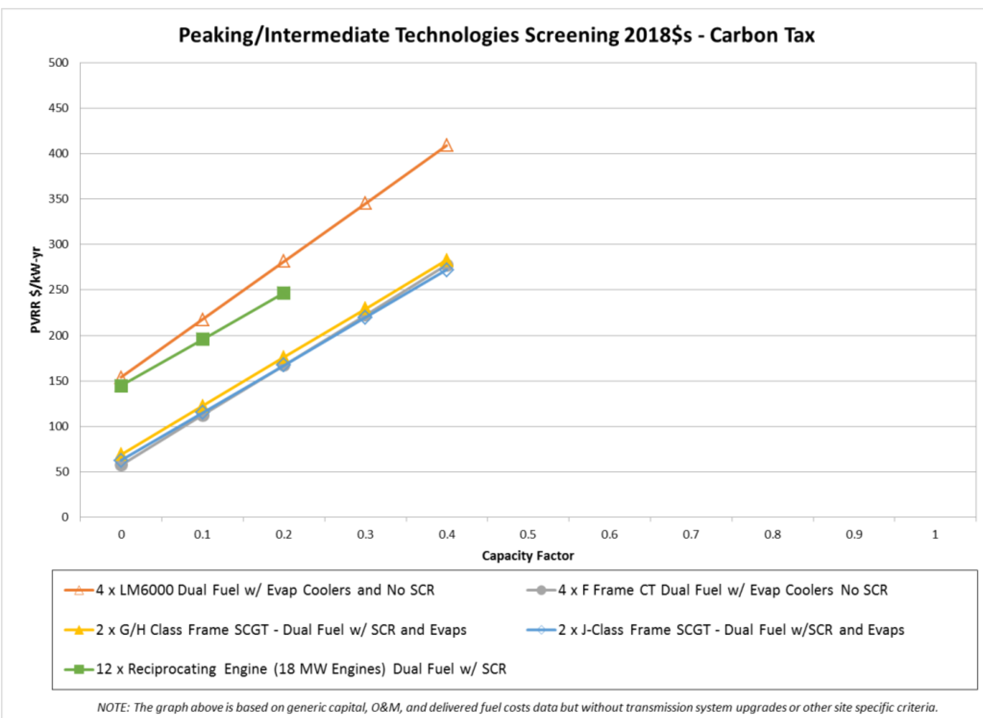
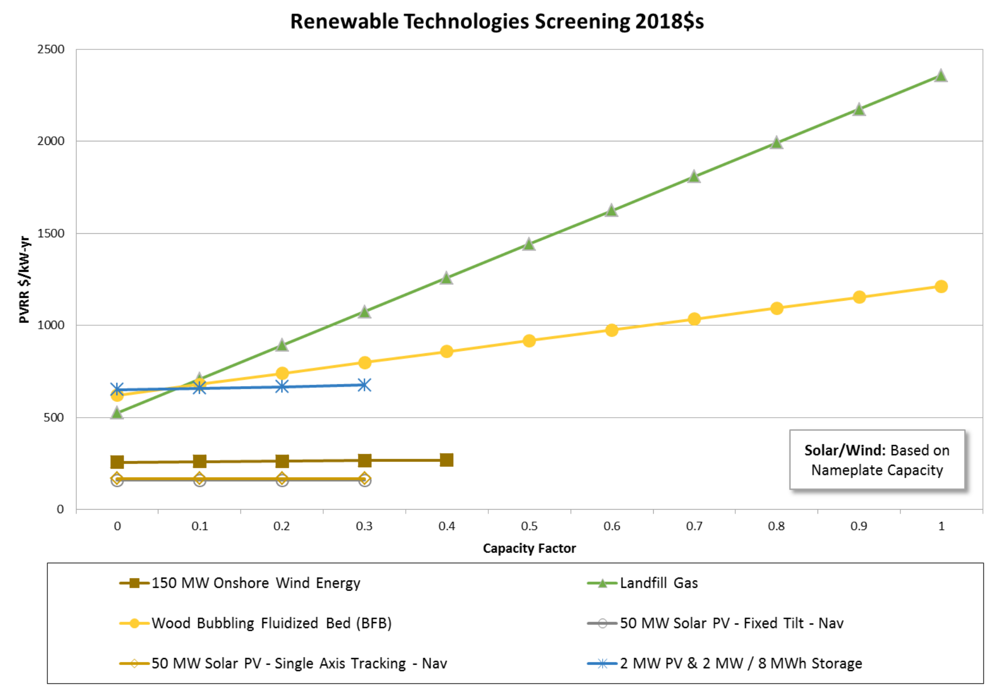
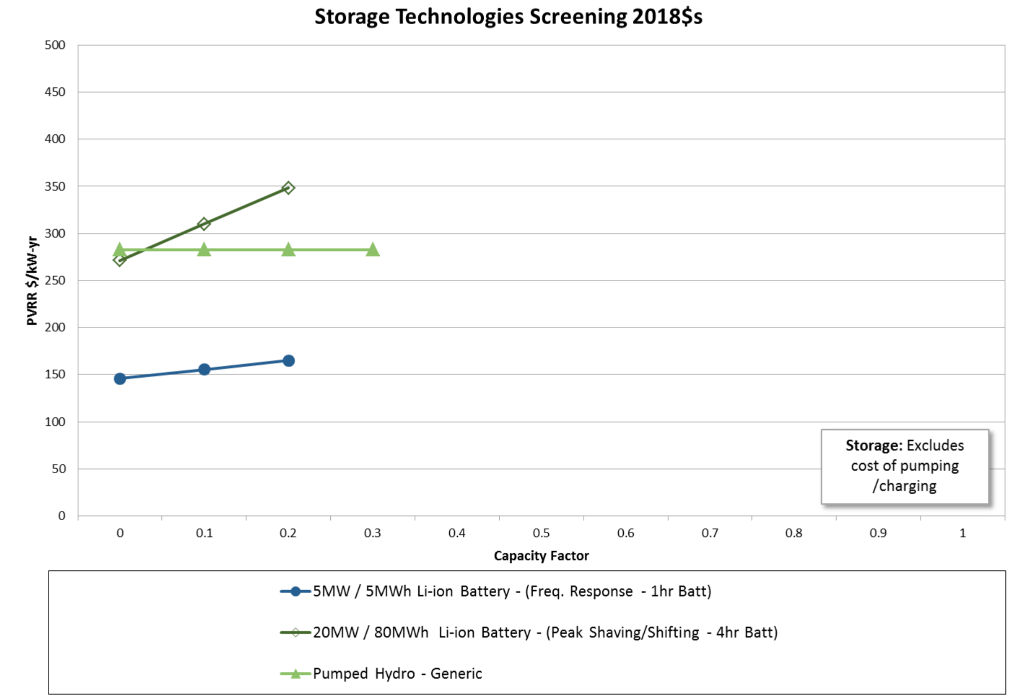

Peaking/Intermediate Technologies Screening 2018$s - No Carbon Tax
PVRR $/kW-yr
Capacity Factor
4 x LM6000 Dual Fuel w/ Evap Coolers and No SCR
4 x F Frame CT Dual Fuel w/ Evap Coolers No SCR
2 x G/H Class Frame SCGT - Dual Fuel w/ SCR and Evaps
2 x J-Class Frame SCGT - Dual Fuel w/SCR and Evaps
12 x Reciprocating Engine (18 MW Engines) Dual Fuel w/ SCR
NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.


Peaking/Intermediate Technologies Screening 2018$s - Carbon Tax
PVRR $/kW-yr
Capacity Factor
4 x LM6000 Dual Fuel w/ Evap Coolers and No SCR
4 x F Frame CT Dual Fuel w/ Evap Coolers No SCR
2 x G/H Class Frame SCGT - Dual Fuel w/ SCR and Evaps
2 x J-Class Frame SCGT - Dual Fuel w/SCR and Evaps
12 x Reciprocating Engine (18 MW Engines) Dual Fuel w/ SCR
NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.



NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.



NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.

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, including the Cross State Air Pollution Rule (CSAPR) NO_x and SO_2 cap-and-trade program, the Mercury and Air Toxics Standards (MATS) rule, and the 2002 North Carolina Clean Smokestacks Act (NC CSA).

As a result of complying with the NC CSA, Duke Energy Progress reduced its SO_2 emissions by approximately 97% from 2000 to 2017. The law also required additional reductions in NO_X emissions beyond Federal requirements, and Duke Energy Progress has achieved an overall reduction of 94% from 1996 to 2017. This landmark legislation, which was passed by the North Carolina General Assembly in June of 2002, calls for some of the lowest state-mandated emission levels in the nation, and was passed with Duke Energy Progress' input and support.

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

Cross-State Air Pollution Rule (CSAPR):

In August 2011, EPA finalized the Cross-State Air Pollution Rule. The CSAPR established state-level caps on annual SO_2 and NO_X emissions and ozone season NO_X emissions from electric generating units (EGUs) across the Eastern U.S., including North 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 complied with Phase I of the CSAPR and with the Phase II annual programs beginning in 2017.

The CSAPR ozone season NO_X 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 September 2016, EPA published the CSAPR Update Rule to revise Phase II of the CSAPR ozone season NO_X program to address interstate transport for the 75 ppb standard. EPA did not include North Carolina in the CSAPR Update rule, stating that the state is not linked to any downwind nonattainment or maintenance receptors for the seasonal ozone standard. Beginning in 2017, Duke Energy Progress plants are not subject to any CSAPR ozone season NOx emission limitations.

Mercury and Air Toxics Standards (MATS) Rule:

In February 2012, EPA finalized the MATS rule to regulate emissions of mercury and other hazardous air pollutants from coal-fired EGUs. The rule established unit-level emission limits for mercury, acid gases, and non-mercury metals. Compliance with the emission limits was required by April 16, 2015, or April 16, 2016 if the state permitting authority granted up to a 1-year compliance extension. Duke Energy Progress is complying with all rule requirements.

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. EPA finalized area designations for the 2015 ozone standard in late 2017 and early 2018. EPA did not designate any nonattainment areas in North Carolina.

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 North Carolina at this time.

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 North 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.

The North Carolina Department of Environmental Quality provided air quality modeling to EPA to characterize SO_2 air quality around the Duke Energy Progress Mayo station, and has established air quality monitoring sites around the Duke Energy Progress Asheville and Roxboro stations. Data collected at these two sites between 2017 and 2019 will be used to demonstrate whether the areas around those facilities meet attainment. In 2017, EPA issued a determination with respect to the Mayo station modeling submittal. EPA classified the area surrounding the Mayo station as "unclassifiable" because of the proximity to the Roxboro station, and will make an additional determination after the air quality monitoring site near the Roxboro station has collected three years of data.

On June 8, 2018, after the five-year review required under the Clean Air Act, EPA proposed to retain the 2010 SO_2 NAAQS.

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 North Carolina being designated nonattainment.

Greenhouse Gas Regulation:

On August 3, 2015, the EPA finalized a rule establishing CO_2 new source performance standards for coal and natural gas combined cycle 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 coal units and 1,000 lb CO_2 per gross MWh for NGCC units. The standard for coal units can only be achieved with carbon capture and sequestration 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 coal 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 coal units. On March 28, 2017, President Trump signed an executive order directing EPA to review the rule and determine whether to suspend, revise or rescind it. On the same day, the Department of Justice (DOJ) filed a motion with the D.C. Circuit Court requesting that the court stay the litigation of the rule while it is reviewed by EPA. Subsequent to the DOJ motion, the D.C. Circuit Court canceled oral argument in the case. On August 10, 2017, the court ordered that the litigation be suspended indefinitely. The rule remains in effect pending the outcome of litigation and EPA's review. EPA has not announced a schedule for completing its review. Duke Energy Progress cannot predict the outcome of these matters but does not expect the impacts of the current final standards will be material to the company's operations.

On October 23, 2015, the EPA published in the Federal Register the final Clean Power Plan (CPP) rule to regulate CO_2 emissions from existing fossil fuel-fired EGUs. The CPP established CO_2 emission rates and mass cap goals that apply to existing fossil fuel-fired EGUs (existing EGUs are units that commenced construction prior to January 8, 2014). Petitions challenging the rule were filed by numerous groups and on February 9, 2016, the Supreme Court issued a stay of the final CPP rule, halting implementation of the CPP until legal challenges are resolved. Oral arguments before 10 of the 11 judges on the D.C. Circuit Court were heard on September 27, 2016. The court has not issued its opinion in the case.

On March 28, 2017, President Trump signed an executive order directing EPA to review the CPP and determine whether to suspend, revise or rescind the rule. On the same day, the Department of Justice filed a motion with the D.C. Circuit Court requesting that the court stay the litigation of the rule while it is reviewed by EPA. On April 28, 2017, the court issued an order to suspend the litigation for 60 days. On August 8, 2017, the court, on its own motion, extended the suspension of the litigation for an additional 60 days. On October 16, 2017, EPA issued a Notice of Proposed Rulemaking (NPR) to repeal the CPP based on a change to EPA's legal interpretation of the section of the Clean Air Act on which the CPP was based. The comment period on EPA's NPR ended April 26, 2018. On December 28, 2017, EPA issued an Advance Notice of Proposed Rulemaking (ANPRM) in which it sought public comment on various aspects of a potential CPP replacement rule. The comment period on the ANPRM ended February 26, 2018. On July 9, 2018, EPA sent a proposed CPP replacement rule to the Office of Management and Budget for review; after that review is completed, EPA will issue its proposal for public comment. Litigation of the CPP remains on hold in the D.C. Circuit Court and the February 2016 U.S. Supreme Court stay of the CPP remains in effect. Duke Energy Progress cannot predict the outcome of these matters.

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 DEP nuclear fueled, coal-fired and combined cycle stations, in South and North 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 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

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

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 expires 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 2019 to 2022 timeframe and intake modifications, if necessary to be required in the 2021 to 2025 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. As originally written, 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, except the limits for CCR leachate, which are effective upon issuance of the permit after the effective date of the rule. For discharges to publicly owned treatment works (POTW), the limits must be met by November 1, 2018, as originally written. Petitions challenging the rule were filed by several groups and all challenges to the rule were consolidated in the Fifth Circuit Court of Appeals. On August 22, 2017, the Fifth Circuit Court of Appeals granted EPA's Motion to Govern Further Proceedings, thereby severing and suspending the claims related to flue gas desulfurization wastewater, bottom ash transport water and gasification wastewater.

Separate from the litigation, on August 11, 2017, EPA announced the decision to conduct a rulemaking to potentially revise the new, more stringent BAT effluent limitations and pretreatment standards for existing sources in the ELG rule that apply to bottom ash transport water and FGD wastewater. Subsequently, EPA finalized a rule on September 18, 2017, postponing the earliest applicability date for bottom ash transport water and FGD wastewater from Nov. 1, 2018 to Nov. 1, 2020 and retained the end applicability date of Dec. 31, 2023. Also, as part of the rule, EPA reiterated its intent to conduct a new rulemaking to review the limitation guidelines for bottom ash transport water and FGD wastewater. EPA projects that a new rule on these two issues will be finalized by December 2019.

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, are installing a closed-loop bottom ash transport water recirculating system.

- FGD Wastewater: All DEP coal-fired units, except for Asheville and Mayo Steam Station, are upgrading or completely replacing 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. As part of that rulemaking, EPA conducted structural integrity inspections of surface impoundments nationwide that were used for disposal of CCR. On April 17, 2015, EPA finalized the first federal regulations for the disposal of CCR (CCR rule). 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 still 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 CCR rule establishes national minimum criteria that includes location restrictions, design standards, structural integrity criteria, groundwater monitoring and corrective action, closure requirements and post-closure care, and recordkeeping, reporting and other operational procedures to ensure the safe disposal and management of CCR.

On March 15, 2018, EPA proposed amendments to the CCR rule to reflect the rule's implementation through state or federal permit programs and to address issues that were remanded back to the agency by the U.S. Court of Appeals for the D.C. Circuit following a settlement with industry and environmental petitioners. On July 17, 2018, EPA finalized a set of changes to the federal CCR rule (Phase One, Part One rule), revising the groundwater protection standards for four constituents and revising the deadline to commence closure of unlined coal ash impoundments that fail to meet groundwater protection standards or the aquifer separation location requirement. EPA also finalized changes that apply only to states with approved CCR permit programs, or where EPA is permitting authority. Currently, no Duke Energy states have approved permit programs. EPA has stated it will address the other proposed revisions in a subsequent rulemaking.

Notably, the Phase One, Part One rule did not change any of the major compliance requirements in the CCR rule, including design criteria, location restrictions, requirements for groundwater monitoring, structural integrity standards, inspections and corrective action.

In addition to the requirements of the federal CCR regulation, CCR landfills and surface impoundments will continue to be independently regulated by the state. On September 20, 2014, the North Carolina Coal Ash Management Act of 2014 (CAMA) became law and was amended on July 14, 2016.

CAMA establishes requirements regarding the beneficial use of CCR, the closure of existing CCR surface impoundments, the disposal of CCR at active coal plants, and the handling of surface and groundwater impacts from CCR surface impoundments. CAMA requires eight CCR surface impoundments in North Carolina to be closed no later than December 31, 2019. It also requires state regulators to provide risk ranking classifications to determine the method and timing for closing the remaining CCR surface impoundments. Currently, North Carolina Department of Environmental Quality (NCDEQ) has categorized all remaining CCR surface impoundments as intermediate risk. CAMA also grants NCDEQ the authority to change an impoundment's classification based on completion of dam safety repairs and the establishment of permanent replacement water supplies within a one-half-mile radius of CCR impoundments. The impact from both state and federal CCR regulations to Duke Energy Progress is significant.

APPENDIX H: NON-UTILITY GENERATION AND WHOLESALE

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

Table H-1: DEP Wholesale Sales Contracts

DEP Aggregated Wholesale Sales Contracts									
Commitment (MW)									
2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
3,965	4,010	3,941	3,923	3,876	3,927	3,980	3,885	3,836	3,887

Notes:

- For wholesale contracts, Duke Energy Progress/Duke Energy Carolinas assume all wholesale contracts will renew unless there is an indication that the contract will not be renewed.
- For the period that the wholesale load is undesignated, contract volumes are projected using the same methodology as was assumed in the original contract (e.g. econometric modeling, past volumes with weather normalization and growth rates, etc.).

Table H-2: DEP Firm Wholesale Purchased Power Contracts

Purchased Power Contract	Summer Capacity (MW)	Location	Volume of Purchases (MWh) Jul 17-Jun 18
Peaking	510	SC	425,406
Peaking	340	SC	267,026
Peaking	220	NC	54,171
Peaking	345	NC	313,461
Peaking	168	NC	70,011
Intermediate	150	NC	1,064,375

Notes: Data represented above represents contractual agreements. These resources may be modeled differently in

APPENDIX I: 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 HB 589.

Below is a summary of the interconnection queue as of June 30, 2018:

Table I-1: DEP QF Interconnection Queue

Utility	Facility State	Energy Source Type	Number of Pending Projects	Pending Capacity (MW AC)
DEP	NC	Battery	2	13.8
		Biomass	1	4.2
		Natural Gas	4	562.7
		Other	1	11.0
		Solar	299	4,519.2
	NC Total		**307**	**5,110.9**
DEP	SC	No Data	5	10.0
		Solar	150	2,464.8
	SC Total		**155**	**2,474.8**
DEP Total			**462**	**7,585.6**

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 J: 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 J-1 lists the transmission line projects that are planned to meet reliability needs. This appendix also provides information pursuant to the North Carolina Utility Commission Rule R8-62.

Table J-1: DEP Transmission Line Additions

	Location		Capacity	Voltage	
Year	**From**	**To**	**MVA**	**KV**	**Comments**
2018	Jacksonville	Wallace	556	230	Uprate
2018	Roxboro Plant	Person (Middle)	1084	230	Uprate
2018	Roxboro Plant	Person (Hyco)	1084	230	Uprate
2018	Richmond	Raeford	1195	230	Relocate, new
2018	Ft. Bragg Woodruff St.	Raeford	1195	230	Relocate, new
2020	Vanderbilt	West Asheville	307	115	Upgrade
2020	Asheboro	Asheboro East North Line	307	115	Upgrade
2020	Sutton Plant	Castle Hayne North Line	239	115	Upgrade
2020	Cleveland Matthews Rd. Tap	Cleveland Matthews Rd	621	230	New
2020	Sutton Plant	Wallace	580	230	Uprate
2020	Jacksonville	Grants Creek	1195	230	New
2020	Newport	Harlowe	681	230	New

DEP Transmission System Adequacy:

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, North Carolina Electric Membership Corporation (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 Reliability Corporation (SERC) policy and North American Electric Reliability Corporation (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 South Carolina and North Carolina Interconnection Procedures.

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 December 2016. 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 K: ECONOMIC DEVELOPMENT

Customers Served Under Economic Development:

In the NCUC Order issued in Docket No. E-100, Sub 73 dated November 28, 1994, the NCUC ordered North Carolina utilities to review the combined effects of existing economic development rates within the approved IRP process and file the results in its short-term action plan. The incremental load (demand) for which customers are receiving credits under economic development rates and/or self-generation deferral rates (Rider EC), as well as economic redevelopment rates (Rider ER) as of June 2018 is:

Rider EC:
25 MW for North Carolina
7 MW for South Carolina

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

BUILDING A **SMARTER** ENERGY FUTURE℠

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