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September 1, 2017

<u>VIA ELECTRONIC MAIL &</u>
<u>HAND DELIVERY</u>

Anthony James, Director of Energy Policy
Trish Jerman, Manager, Energy Programs
Office of Regulatory Staff
Energy Office
1401 Main Street, Suite 900
Columbia, SC 29201

RE: Duke Energy Carolinas, LLC's 2017 Integrated Resource Plan

Anthony and Trish:

Enclosed is the Public Version of Duke Energy Carolinas, LLC's 2017 Integrated Resource Plan Annual Report which we are delivering to you pursuant to S.C. Code § 58-37-40.

Please contact me should you have any questions.

Yours truly,

Frank R. Ellerbe, III

FRE:tch

cc: Dawn Hipp, ORS – Director of Utilities, Safety & Transportation
Nanette S. Edwards, ORS - Deputy Executive Director
Jeffrey M. Nelson, ORS - Chief Counsel & Director of Legal Services
Shannon Bowyer Hudson, ORS - Deputy Director of Legal Services
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May 24, 2018

VIA ELECTRONIC FILING

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

Re: **Duke Energy Carolinas, LLC Notification of Hydro Units Retirement**
Duke Energy Carolinas, LLC's 2017 Integrated Resource Plan
Docket No. 2017-10-E

Dear Ms. Boyd:

By this letter, Duke Energy Carolinas, LLC ("DEC" or the "Company") wishes to notify the Commission and all parties that Duke Energy Carolinas, LLC plans to retire twelve small hydroelectric ("hydro") peaking units near Great Falls, South Carolina, in connection with the 2017 Integrated Resource Plan Update:

Great Falls Units 3, 4, 7, and 8
Rocky Creek Units 1-8

These peaking units, which were built over 100 years ago and have a total generating capacity of 36 MW, have not been dispatched in several years. The more efficient units at the nearby Dearborn and Cedar Creek hydro facilities are always dispatched first, to make the best use of available water flows. The Great Falls and Rocky Creek units have served DEC customers well over their useful lives but, based upon condition and economic evaluations, the Company determined that these units will no longer provide economic and reliable commercial service to customers. Following the Catawba-Wateree relicensing order, the Federal Energy Regulatory Commission on June 15, 2017 approved DEC's plan to decommission all twelve units by retirement in place. The Company has removed these assets from plant in service, and the units will be retired effective May 31, 2018.

If you have any questions, please let me know.

Sincerely,

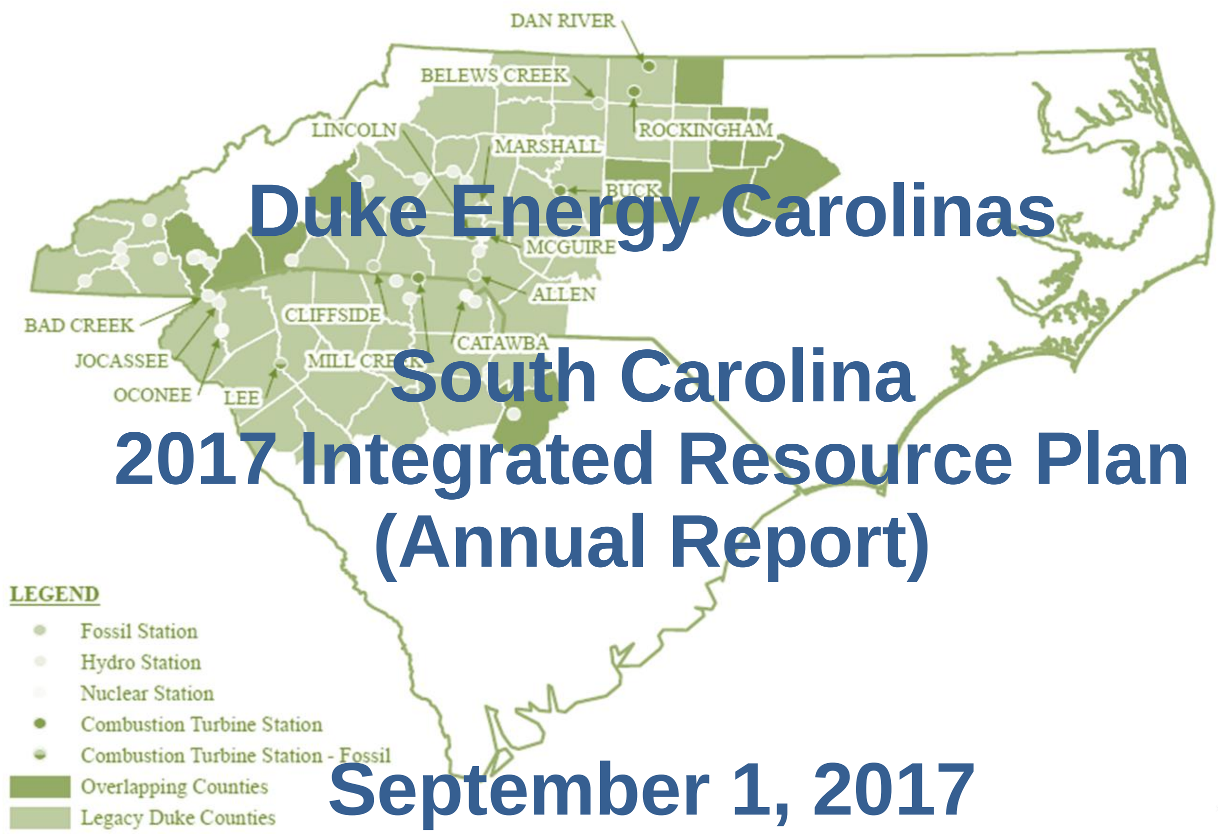
Heather Shirley Smith

Heather Shirley Smith

cc: Ms. Nanette Edwards, Esq., Office of Regulatory Staff
Ms. Dawn Hipp, Office of Regulatory Staff
Mr. Jeffery M. Nelson, Esq. Office of Regulatory Staff
Mr. Andrew Bateman, Esq., Office of Regulatory Staff
Mr. Michael Seaman-Huynh, Office of Regulatory Staff
Parties of Record

Duke Energy Carolinas

South Carolina
2017 Integrated Resource Plan
(Annual Report)



September 1, 2017

PUBLIC

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ABBREVIATIONS	
AMP	Aging Management Programs
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CC	Combined Cycle
CCR	Coal Combustion Residuals
CCS	Carbon Capture Sequestration
CECPCN	Certificate of Environmental Compatibility and Public Convenience and Necessity
CFL	Compact Fluorescent Light bulbs
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
COD	Commercial Operation Date
COL	Combined Construction and Operating License
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan
IPI	Manufacturing Industrial Production Index
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
DC	Direct Current
DEC	Duke Energy Carolinas
DEP	Duke Energy Progress
DOE	Department of Energy
DSM	Demand Side Management
EE	Energy Efficiency Programs
EGU	Electric Generating Unit
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FLG	Federal Loan Guarantee
GALL	Generic Aging Lessons Learned Report
GHG	Greenhouse Gas
HB 589	Competitive Energy Solutions for North Carolina (House Bill 589)
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation and Air Conditioning
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Plan
IS	Interruptible Service
ILR	Inverter Load Ratio
ITC	International Trade Commission
ITC	Investment Tax Credit
JDA	Joint Dispatch Agreement`
KW	kilowatt

ABBREVIATIONS (CONT.)	
LCR Table	Load, Capacity, and Reserve Margin Table
LEED	Leadership in Energy and Environmental Design
LOLE	Loss of Load Expectation
MACT	Maximum Achievable Control Technology
MATS	Mercury Air Toxics Standard
MMBtu	1 million British Thermal Units
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NC	North Carolina
NCDAQ	North Carolina Division of Air Quality
NCEMC	North Carolina Electric Membership Corporation
NCMPA1	North Carolina Municipal Power Agency #1
NC REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
NCTPC	NC Transmission Planning Collaborative
NCUC	North Carolina Utilities Commission
NERC	North American Electric Reliability Corp
NGCC	Natural Gas Combined Cycle
NO_x	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standard
NUREG	Nuclear Regulatory Commission Regulations
OATT	Open Access Transmission Tariff
O&M	Operations and Maintenance
ONS	Oconee Nuclear Station
PC	Pulverized Coal
PEV	Plug-In Electric Vehicles
PMPA	Piedmont Municipal Power Agency
PPA	Purchase Power Agreement
PSCSC	Public Service Commission of South Carolina
PV	Photovoltaic
PVRR	Present Value Revenue Requirements
PURPA	Public Utility Regulatory Policies Act
QF	Qualifying Facility
REC	Renewable Energy Certificates
REPS	Renewable Energy and Energy Efficiency Portfolio Standard
RFP	Request for Proposal
RIM	Rate Impact Measure
RPS	Renewable Portfolio Standard
SAE	Statistically Adjusted End-Use Models
SAT	Single-Axis Tracking
SC	South Carolina
SC DER	South Carolina Distributed Energy Resource Program
SCE&G	South Carolina Electric & Gas

ABBREVIATIONS (CONT.)	
SCR	Selective Catalytic Reduction
SEPA	Southeastern Power Administration
SERC	SERC Reliability Corporation
SG	Standby Generation
SIP	State Implementation Plan
SLR	Subsequent License Renewal
SO_2	Sulfur Dioxide
SRP-LR	Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants
SRP-SLR	Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants
STAP	Short-Term Action Plan
TAG	Technology Assessment Guide
TRC	Total Resource Cost
The Company	Duke Energy Carolinas
The Plan	Duke Energy Carolinas Annual Plan
UCT	Utility Cost Test
UEE	Utility Energy Efficiency Programs
U.S.	United States
VACAR	Virginia/Carolinas
VAR	Volt Ampere Reactive

1. INTRODUCTION:

For more than a century, Duke Energy Carolinas (DEC or the Company) has provided affordable and reliable electricity to customers in South Carolina (SC) and North Carolina (NC) now totaling more than 2.5 million in number. The Company continues to serve its customers by planning for future demand requirements in the most reliable and economic way possible using increasingly clean forms of energy.

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

As per the PSCSC Order No. 98-502 Approving Least-Cost Integrated Resource Planning Process, the Company is providing a Short-Term Action Plan, a 15-year plan and other pertinent information compliant with said Order.

The Company files separate IRPs for South Carolina and North Carolina. However, the IRP analyzes the system as one DEC 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.

2. <u>2017 IRP SUMMARY:</u>

Each year, as required by the PSCSC, DEC submits an IRP detailing potential infrastructure needed to meet the forecasted electricity requirements for its customers over the next 15 years. The 2017 IRP is the best projection of how the Company's capacity and energy portfolio will look over the next 15 years, based on current data assumptions. This projection may change over time as variables such as the projected load forecasts, fuel price forecasts, environmental regulations, technology performance characteristics and other outside factors change.

The proposed plan will meet the following objectives:

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

In the 2017 IRP, DEC developed four cases which reflect updates to the 2016 IRP base case. The first case, or the "Base Case," is an update to the presented base case in the 2016 IRP, which includes the expectation of future carbon legislation and no relicensing of existing nuclear units. Additionally, a "No Carbon Case" was developed in which no carbon legislation, without nuclear relicensing, is considered. Finally, given the uncertainty of new and existing nuclear generation, the Base Case and No Carbon Case were also evaluated with relicensing of existing nuclear units. All results presented in this IRP represent the Base Case without nuclear relicensing, except where otherwise noted. As discussed in more detail throughout this report, two significant updates in this year's IRP are developments around the Lee Nuclear project and changes in DEC's renewable energy forecast.

<u>Lee Nuclear</u>

On December 19, 2016, the Company received the Combined Construction and Operating License (COL) for the Lee Nuclear Project from the United States Nuclear Regulatory Commission (U.S. NRC). On August 25, 2017, DEC filed a request to cancel the Lee Nuclear Project as that project was originally envisioned and included in prior IRPs. Also, that cancellation request is now pending before the North Carolina Utilities Commission (NCUC) in

Docket Nos. E-7, Sub 819 and E-7 Sub 1146. DEC's decision to cancel the project resulted from events that have occurred subsequent to receipt of the Lee Nuclear COL. These events include the AP-1000 technology owner, designer and engineer, Westinghouse, and its parent company, Toshiba Corporation, indicating that they intend to exit the nuclear construction business in the U.S., including the Lee Project; the subsequent bankruptcy of Westinghouse, and the substantial cost increases and schedule delays associated with the Vogtle and V.C. Summer new nuclear construction projects; the latter of which South Carolina Electric & Gas Company (SCE&G) and project joint owner, Santee Cooper, recently canceled.

In addition to these developments, revised projections indicate that new nuclear baseload capacity is needed only under a carbon-constrained scenario with the assumption of no existing nuclear re-licensing. Even in that scenario, the added capacity would not be needed until much later in the 15-year planning horizon (2031, 2033) than projected in the 2016 IRP.

Over the next year, the Company will continue to monitor and analyze key developments on factors impacting the potential need for future new baseload nuclear generation. Such factors include further developments on the Vogtle project, progress on existing unit relicensing efforts and changes in fuel prices and carbon policy.

Renewable Energy

The Company continues to aggressively pursue additional cost-effective renewable resources as a growing part of its energy portfolio. The Company's commitment, coupled with supporting legislation such as South Carolina's Distributed Energy Resource Program Act (SC DER Program) and North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS), have led to significant growth in renewable resource development in the Carolinas.

Furthermore, on July 27, 2017, North Carolina Governor Cooper signed into law the "Competitive Energy Solutions for North Carolina" bill or House Bill 589 (HB 589). As discussed in more detail in Section 4.b. of this report, HB 589 calls for the establishment of a competitive procurement process by which the Company will pursue additional solar resources in its South Carolina and North Carolina service territory, provided that they are cost-effective for consumers. Commensurately, the update contained in this year's IRP reflects the initial forecast of increases in renewable additions as a result of HB 589.

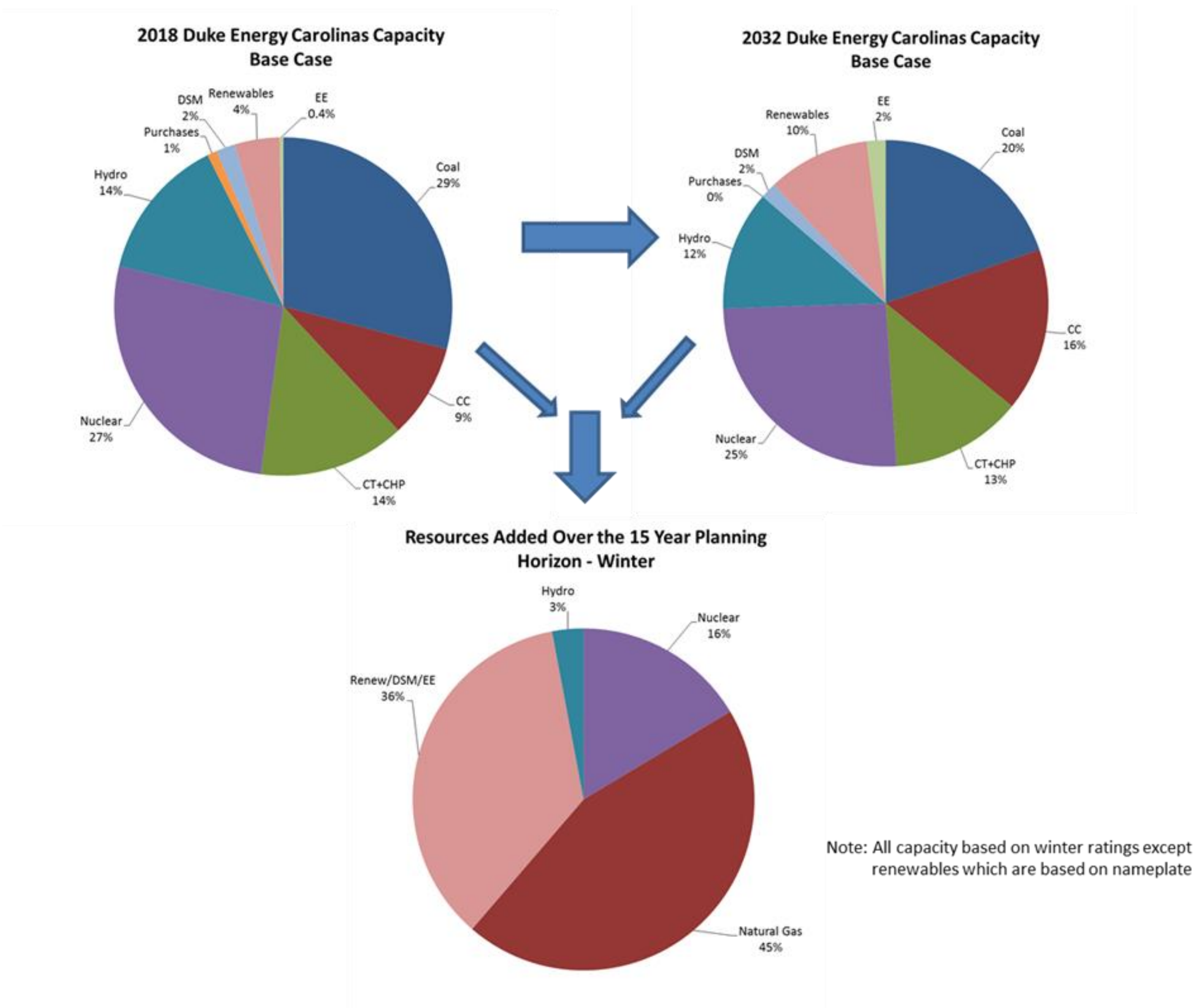
It must be noted, however, that at the time of this report filing, the rules, regulations and details surrounding the implementation of HB 589 are still under development. As these rules are finalized and as the Company gains experience with the new competitive procurement process, updated forecasts will be presented in subsequent IRPs.

In addition to the Lee Nuclear and Renewable Energy updates, other changes since the 2016 IRP are discussed in this document. Those changes include:

- Load Forecast
- Combined Heat & Power (CHP) Projections
- Resource Adequacy
- Fuel Costs
- Carbon Assumptions
- Technology Construction and Operating Costs
- Transmission Planned and Under Construction

As shown in the 2017 IRP Base Case, projected incremental needs are driven by load growth and the retirement of aging generation resources and expiration of purchase power contracts. The 2017 IRP seeks to achieve a reliable, economic long-term power supply through a balance of incremental renewable resources, EE, DSM, and traditional supply-side resources planned over the coming years which allows the Company to maintain a diversified resource mix while also providing increasingly clean energy. Chart 2-A represents the incremental investments required to meet future needs.

Chart 2-A 2018 and 2032 Base Case Winter Capacity Mix and Sources of Incremental Capacity



3. IRP PROCESS OVERVIEW:

To meet the future needs of DEC's customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, the Company 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 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 with 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.

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

It should be noted that DEC considers the non-firm energy purchases and sales associated with the Joint Dispatch Agreement (JDA) with Duke Energy Progress (DEP) in the development of its independent Base Case. To accomplish this, DEC and DEP plans are determined simultaneously to minimize revenue requirements of the combined jointly dispatched system while maintaining independent reserve margins for each company.

For the first time in the 2016 IRP, DEC developed resource plans that also include new resource additions driven by winter peak demand projections inclusive of winter reserve requirements. The completion of a comprehensive reliability study demonstrated the need to include winter peak planning in the IRP process. The study recognized the growing volatility associated with winter morning peak demand conditions such as those observed during recent polar vortex events. The study also incorporated the expected significant growth in solar that provide valuable assistance in meeting summer afternoon peak demands on the system but do little to assist in meeting demand for power on cold winter mornings. As discussed in more detail in the Resource Adequacy section, the significant penetration of solar resources and the associated impact on summer versus winter reserves is the primary driver for the Company's shift to winter capacity planning. Based on results of the reliability study, DEC is now utilizing a winter planning reserve margin of 17% in its planning process.

For the 2017 Update IRP, the Company presents a Base Case with a carbon tax beginning in 2026. The Clean Power Plan (CPP) rule that was finalized on August 3, 2015 by the EPA is under interagency review for potential repeal. As a result, the timing and details of any potential future carbon legislation are highly uncertain. While future carbon legislation is unknown, the Company feels that it is prudent to continue to plan for this scenario, as well as other potential future scenarios. Furthermore, a primary focus of this update IRP is the Short-Term Action Plan (STAP), which covers the period 2018 to 2022. It was determined that the inclusion of the carbon tax did not have a significant impact on the STAP, and therefore the majority of the data presented in this report represents the Base Case.

Figure 3-A represents a simplified overview of the resource planning process in the update years (odd years) of the IRP cycle.

Figure 3-A Simplified IRP Process

Data Inputs → **Production Cost Modeling** → **Discussion of Significant Changes** → **Short-Term Action Plan**

Data Inputs

- Load Forecast
- Fuel Price Forecasts
- Existing Generation
- Energy Efficiency
- Demand Response
- Renewable Resources
- New Generation
- Environmental Legislation
- Reserve Margin

Production Cost Modeling

- With CO_2 and No Nuclear Relicensing (Base Case)
- Without CO_2 and No Nuclear Relicensing
- With CO_2 and Nuclear Relicensing
- Without CO_2 and Nuclear Relicensing

Discussion of Significant Changes

- Since 2016 Biennial IRP
  - Load Forecast
  - Fuel Prices
  - Nuclear Assumptions
  - Renewables (HB589)
  - CHP and Energy Storage
  - Carbon Assumptions
  - Transmission Planned or Under Construction

Short-Term Action Plan

- 2018 through 2022

4. SIGNIFICANT CHANGES FROM THE 2016 IRP:

As an initial step in the IRP process, all production cost modeling data is updated to include the most current data. Throughout the year, best practices are implemented to ensure the IRP best represents the Company's planning assumptions including load forecast, generation system, conservation programs, renewable energy and fuel costs. The data and methodologies are regularly updated and reviewed to determine if adjustments can be made to further improve the IRP process and results.

As part of the review process certain data elements with varying impacts on the IRP, inevitably change. A discussion of new or updated data elements that have the most substantial impact on the 2017 IRP is provided below.

a) Load Forecast

The Company continues to utilize the statistically adjusted end use models (SAE) provided by ITRON to forecast sales and peaks with reasonable results.

Each time the forecast is updated, the most currently available historical and projected data is used. The Spring 2017 forecast which was used in the development of the Company's 2017 IRP utilizes:

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

Additional focus is being placed on the hourly shaping of sales, which plays a critical role in forecasting summer and winter peaks. While much of this work is ongoing and will be incorporated in the 2018 IRPs, the Company continues to review the weather sensitivity of winter and summer peaks, as well as the hourly shaping of behind-the-meter solar, utility sponsored energy efficiency programs (UEE), electric vehicles, and other variables.

Additional focus is also being placed on Duke's load research sample data, to gain a better understanding of historical hourly demand trends, winter and summer peaking characteristics by customer class, and minimums by customer class, in continuous efforts to improve forecast accuracy.

Table 4-A depicts the projected average annual growth rates of several key drivers from DEC's Spring 2017 Forecast.

Table 4-A Key Drivers

	2018-2032
Real Income	2.7%
Manufacturing Industrial Production Index (IPI)	1.3%
Population	1.6%

In addition to economic, demographic, and efficiency trends, the forecast also incorporates the expected impacts of utility sponsored energy efficient programs, as well as projected effects of electric vehicles and behind-the-meter solar technology.

The results of the Spring 2017 Forecast as compared to Spring 2016 Forecast is presented in Table 4-B below.

Table 4-B 2017 Load Forecast Growth Rates vs. 2016 Load Forecast Growth Rates (Retail and Wholesale Customers)

	2017 Forecast (2018 – 2032)			2016 Forecast (2017 – 2031)		
	Summer Peak Demand	Winter Peak Demand	Energy	Summer Peak Demand	Winter Peak Demand	Energy
Excludes impact of new EE programs	0.7%	1.0%	0.7%	1.3%	1.4%	1.1%
Includes impact of new EE programs	0.4%	0.9%	0.4%	1.2%	1.3%	1.0%

b) Renewable Energy

The growth of renewable generation in the United States continues to outpace that of non-renewable generation. In 2016, more than 16,000 megawatts (MW) of wind and solar capacity were installed nationwide compared to approximately 10,000 MW for natural gas, coal, nuclear, and other technologies.[1]

North Carolina ranked in the top five in the country in solar capacity added in 2016, second behind only California in total solar capacity online. Duke Energy's compliance with NC REPS and the Public Utilities Regulatory Policy Act (PURPA) as well as the Federal Investment Tax Credit (ITC) were key factors behind the high penetration of solar in the state. North Carolina's current favorable avoided cost rate and 15-year contract terms for qualifying facilities (QFs) under PURPA have contributed to record numbers of projects in the interconnection queue, with the DEC and DEP combined solar queue representing more than 7,000 MW.

To reduce the dependence on PURPA while continuing to support solar growth in a sustainable and economically attractive manner, on July 27, 2017 Governor Cooper signed into law the "Competitive Energy Solutions for North Carolina" bill or House Bill 589 (HB 589). The law reduces the maximum size of standard contracts offered to solar projects to 1 MW and reduces the contract term to 10 years.

HB 589 also introduces a competitive procurement process for renewable resources including large-scale solar facilities that continues to enable third-party and utility-owned renewable development. Capacity referred to as the "Transition" MW in this document represents the total capacity of projects in the combined Duke Balancing Authority area that are (1) already connected; or (2) have entered into purchase power agreements and interconnection agreements as of the end of the 45-month competitive procurement period, provided that they are not subject to curtailment or economic dispatch. HB 589 targets 2,660 MW of competitively procured renewable resources over a 45-month period, which may vary based on the amount of "Transition" MW at the end of the 45-month period. It is expected that 3,500 MW of "Transition" MW will exist in the combined Duke Balancing Authority area at the end of the 45-month period. The capacity additions from the competitive procurement will be in addition to the expected 3,500 MW of "Transition" MW. Projects in both North Carolina and South Carolina are eligible for the competitive procurement process.

Growing customer demand, the federal ITC, and declining installed solar costs make solar capacity the Company's primary renewable energy resource in the 2017 IRP. The 2017 IRP makes the following key assumptions regarding renewable energy:

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

- Installed solar capacity increases in DEC from 889 MW in 2018 to 2,890 MW in 2032;
- Achievement of the SC DER Program goal of 120 MW of solar capacity located in DEC-SC;
- Compliance with NC REPS continues to be met through a combination of solar, other renewables, EE, and Renewable Energy Certificate (REC) purchases; and
- Passage of HB 589 and continuing solar cost declines drive solar capacity growth above and beyond NC REPS requirements.

Interconnection Queue and the Transition

Through the end of 2016, DEC had more than 500 MW of third party utility scale solar on its system, with approximately 200 MW interconnecting in 2016. When renewable resources were evaluated for the 2017 IRP, DEC reported another approximately 35 MW of third party solar under construction and more than 1,500 MW in the interconnection queue. Table 4-C depicts the interconnection queue for DEC as of June 30, 2017.

Table 4-C DEC QF Interconnection Queue (as of June 30, 2017)

Utility	FacilityState	Energy Source Type	Number of Pending Projects	Pending Capacity (MW AC)
DEC	**NC**	Biogas *	1	0
		Biomass	3	11
		Hydroelectric	1	4
		Landfill Gas	1	2
		Solar	137	1,220
	NC Total		**143**	**1,237**
	SC	Landfill Gas	1	5
		Natural Gas *	1	0
		Other	1	0
		Solar	57	630
	SC Total		**60**	**635**
DEC Total			**203**	**1,872**

* No Capacity entered into system

Projecting future solar connections from the interconnection queue has presented a significant challenge due to the large number of project cancellations and ownership transfers. If the aggregate capacity in the "Transition" 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.

DEC's contribution to the "Transition" depends on a number of variables including connecting projects under construction, the number of projects in the queue with power purchase and/or interconnection agreements, SC DER Program Tier I, and capacity connected as a result of the RFP for NC REPS compliance issued in the Fall of 2016.

The DEC RFP for NC REPS compliance is expected to be the greatest contributor of "Transition" MW beyond the over 500 MW currently connected as more than 300 MW of solar may connect to meet the 750,000 MWHs requested in the RFP. In total, DEC may contribute roughly one-quarter of the "Transition" MW with DEP accounting for the remaining three-quarters.

NC REPS Compliance

DEC 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 solar, hydro, biomass, landfill gas, wind, and energy efficiency resources. DEC's long-term general compliance needs are expected to be met through a combination of renewable resources, including solar RECs obtained through the HB 589 competitive procurement process.

HB-589 Competitive Procurement and Utility-Owned Solar

DEC continues to evaluate utility-owned solar additions to support its NC compliance targets and to grow its renewables portfolio. For example, DEC has recently connected two new utility-scale solar projects in NC as part of its efforts to encourage emission free generation resources and help meet its NC compliance targets, totaling 75 MW-AC:

- Monroe Solar Facility – 60 MW, located in Union County, NC placed in service on March 29, 2017; and
- Mocksville Solar Facility – 15 MW, located in Davie County, NC placed in service on December 16, 2016.

As mentioned above, HB 589 calls for 2,660 MW of additional solar in the Carolinas, which may vary depending upon how the actual "Transition" MW compare to the initial 3,500 MW estimate. RFPs will be issued over a 45-month period under the competitive procurement process; DEC may own up to 30% of the competitive procurement volume it self-develops. DEC will also evaluate the potential for acquiring facilities where appropriate. HB 589 does not stipulate a limit for DEC's option to acquire third party projects. Since the majority of the solar projects connected during the "Transition" will be in DEP's territory, DEC is expected to have the majority of the competitive procurement projects, helping to balance the portfolios and mitigate additional operational challenges in DEP.

HB 589 requires that competitive bids are priced below utility's avoided cost rates, as approved by the NCUC, or it will not be selected. Therefore, the cost of solar is a critical input for forecasting how much of the competitive procurement will materialize. 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. Changes in these factors will result in changing avoided cost values over the upcoming years with the potential to impact the cost-effectiveness of future competitive procurement solicitations.

Similarly, solar costs are also influenced by a number of variables. Panel prices have decreased at a significant rate and are expected to continue to decline. However, there are political factors, such as the Suniva International Trade Commission (ITC) case, that have the potential to increase panel prices. 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. [2] 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. DEC will incorporate different configurations further in the 2018 IRP.

In summary, there is a great deal of uncertainty in both the future avoided cost value of solar and the expected price of solar installations in the years to come. As a result, the Company

[2] In April, 2017, Suniva officially filed a petition to the ITC under Section 201 of the Trade Act of 1974. Suniva is requesting relief against imports from all geographic sources and requesting both a minimum price on crystalline silicon photovoltaic modules (initially \$0.78/W) and a tariff on cells (initially \$0.40/W). As expected, the petition only applies to crystalline silicon. (GTM Research Suniva Trade Dispute Update)

will continue to closely monitor and report on these changing factors in future IRP and competitive procurement filings.

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, DEC is positioning itself to properly integrate renewable resources to the grid regardless of ownership.

In addition to ensuring DEC 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.

HB 589 Customer Programs

In addition to the competitive procurement process, 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 be a great complement to the existing customer oriented strategies in DEC such as the Green Source Rider and SC DER Program.

The Green Source Rider allows DEC to procure renewable energy on behalf of the customer. The customer pays for the REC during their project term and DEC may acquire the REC following the contract term. Numerous customers have participated in this program, which stands at approximately 99 MW-AC (nameplate capacity) and is expected to grow to just over 103 MW-AC by 2017.

The renewable energy procurement carve out for large customers such as military installations and universities may have similarities to the Green Source Rider program. 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 UNC system (250 MW of the 600 MW). The 2017 IRP base case assumes all 600 MW of this program materialize, with the DEC/DEP 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 DEC. This program may have similarities to SC DER Program's community solar program. The 2017 IRP base case assumes that all 20 MW of the program materialize.

HB 589 also calls for a rebate program for rooftop solar as well as a leasing program, and the establishment of revised net metering rates. Given the uncertainty around the timing and structuring of these programs, it is challenging to assess the impact HB 589 will have on rooftop solar adoption in NC.

SC DER Program Solar

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

- Tier I: 40 MW of solar capacity from facilities each >1 MW and < 10 MW in size.
- Tier II: 40 MW of behind-the-meter rooftop 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 40 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 can directly invest in additional solar generation to complete Tier III.

DEC is in the process of evaluating offers made for Tier I solar and will meet the 2020 in-service deadline specified in the DER Program. Tier II has resulted in significant growth in rooftop solar in South Carolina. DEC SC now has over 30 MW of rooftop solar installed, which is currently more than DEC NC.

Battery Storage and Wind

In addition to solar, the Company is assessing other technologies such as battery storage and wind. Battery storage costs are expected to continue to decline significantly which may make it a viable option in the long run to support grid services, including frequency regulation, solar smoothing, and/or energy shifting from localized renewable energy sources with a high incidence of intermittency (i.e. solar and wind). The Company intends to begin investing in multiple 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 Duke Energy and its customers to evaluate the costs and impacts of batteries deployed at a significant scale, explore the nature of new offerings desired by customers, and fill knowledge gaps. Among the DEC and DEP territories, as much as 75 MW of utility-owned and operated battery storage may be dispersed in the 2019-2021 time period. Additionally, HB 589 calls for an energy storage study to assess the economic potential for NC customers.

DEC considers wind a potential energy resource in the long term to support increased renewables portfolio diversity and long-term general compliance need. Therefore, DEC issued a RFP on August 15, 2017 for delivered energy, capacity, and associated RECs from wind projects ranging in size from 100 to 500 MW, and capable of delivering energy on or before December 31, 2022. To represent the RFP, a placeholder of 200 MW was added to the 2017 IRP base case starting in 2023.

Summary of Expected Renewable Resource Capacity Additions

The 2017 IRP incorporates the base case renewable capacity forecast below. This case includes renewable capacity required for compliance with SC DER Program, NC REPS, non-compliance PURPA renewable purchases part of the "Transition" MW of HB 589, as well as Green Source Rider, and the additional three components of HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). 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 4-D below.

While solar does not normally reach its maximum output at the time of DEC's expected peak load in the summer, solar's contribution to summer peak load is large enough (46% of nameplate solar capacity) that it may push the time of summer peak from hour beginning 4:00 PM to 5:00 PM or later if solar penetration levels continue to increase. However, solar is unlikely to have a similar impact on the morning winter peak due to lower expected solar output in the morning hours (5% of nameplate solar capacity). Contribution to peak assumptions will continue to be evaluated in 2018, with specific attention given to different configurations of solar projects with fixed tilt or tracking systems and different ILRs. Wind is assumed to contribute 13% of nameplate capacity to both the winter and summer peaks.

Table 4-D DEC Base Case Total Renewables

DEC Base Renewables - Compliance + Non-Compliance													
	MW Nameplate				MW Contribution to Summer Peak				MW Contribution to Winter Peak				
	Solar	Biomass/ Hydro	Wind	Total	Solar	Biomass/ Hydro	Wind	Total		Solar	Biomass/ Hydro	Wind	Total
2018	889	121	0	1010	409	121	0	530	2017/2018	34	121	0	155
2019	1214	116	0	1330	558	116	0	674	2018/2019	44	116	0	160
2020	1333	115	0	1448	613	115	0	728	2019/2020	61	115	0	176
2021	1711	115	0	1826	787	115	0	902	2020/2021	67	115	0	182
2022	2088	96	0	2184	960	96	0	1056	2021/2022	86	96	0	182
2023	2482	90	200	2572	1142	90	26	1232	2022/2023	104	90	26	194
2024	2890	88	200	2978	1329	88	26	1417	2023/2024	124	88	26	212
2025	2963	86	200	3049	1363	86	26	1449	2024/2025	144	86	26	230
2026	2949	77	200	3026	1356	77	26	1433	2025/2026	148	77	26	225
2027	2934	74	200	3008	1350	74	26	1424	2026/2027	147	74	26	221
2028	2919	76	200	2995	1343	76	26	1419	2027/2028	147	76	26	223
2029	2905	76	200	2981	1336	76	26	1412	2028/2029	146	76	26	222
2030	2890	73	200	2963	1329	73	26	1402	2029/2030	145	73	26	218
2031	2890	66	200	2956	1329	66	26	1395	2030/2031	145	66	26	211
2032	2890	60	200	2950	1329	60	26	1389	2031/2032	145	60	26	205

* Solar includes 0.5% per year degradation

While high and low solar penetration scenarios were not evaluated compared to the base case for the 2017 IRP, volumes can certainly vary greatly, especially for solar resources. Solar installations may fall short of the Base Case if the competitive procurement for universal solar facilities, renewable energy procurement for large customers, and/or community solar programs of HB 589 don't materialize to their limits for some of the reasons mentioned earlier. On the upside, there is also the unknown of what occurs after HB 589 which is assumed to have no additional solar growth in the Base Case. While new policy may stimulate additional growth, a high sensitivity could occur given further improvements in the economics for solar through events such as high carbon dioxide emission regulations or taxes, lower solar capital costs, economical solar plus storage, and/or continuation of renewal subsidies, and/or stronger renewable energy mandates.

c) <u>Nuclear Assumptions</u>

In its last filed IRP on September 1, 2016, DEC indicated it continued to have a long-term need for new nuclear generation. The Base Case scenario, which included a cost on carbon emissions, assumed new nuclear resources to meet load and minimum planning reserve margin with Lee Nuclear additions in 2026 and 2028 (2,234 MW).

On December 19, 2016, the Company received the Combined Construction and Operating License (COL) for the Lee Nuclear Project from the U.S. Nuclear Regulatory Commission. On August 25, 2017, DEC filed a request to cancel the Lee Nuclear Project as that project was originally envisioned and included in prior IRPs. On August 25^{th}, DEC filed notice of its request with the Public Service Commission of South Carolina in Docket 2011-20-E. Also, that request is now pending before the NCUC in Docket Nos. E-7, Sub 819 and E-7 Sub 1146. DEC's decision to cancel the project resulted from events that have occurred subsequent to receipt of the Lee Nuclear COL. These events include the AP-1000 technology owner, designer and engineer, Westinghouse, and its parent company, Toshiba Corporation, indicating that they intend to exit the nuclear construction business in the U.S., including the Lee Project; the subsequent bankruptcy of Westinghouse, and the substantial cost increases and schedule delays associated with the Vogtle and V.C. Summer new nuclear construction projects; the latter of which SCE&G and project joint owner, Santee Cooper, recently canceled.

In addition to these developments, revised projections indicate that new nuclear baseload capacity is needed only under a carbon-constrained scenario with the assumption of no existing nuclear re-licensing. Even in that scenario, the added capacity would not be needed until much later in the 15-year planning horizon (2031, 2033) than projected in the 2016 IRP.

The Company views all of its existing nuclear fleet as excellent candidates for license extensions, however to date, no existing nuclear plant operating licenses have been extended from 60 years to 80 years in the United States. As such, there is uncertainty regarding license extension, and any costs associated with continuing to operate for an additional 20 years. Given the uncertainty of license extension, the IRP Base Case does not assume license extension at this time, but rather considers relicensing as a sensitivity to the Base Case. The Company is evaluating the feasibility of relicensing its existing nuclear resources. A discussion of the Company's activities is included below.

<u>Subsequent License Renewal (SLR) for Nuclear Power Plants</u>

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.* Additionally, the NRC has issued regulatory guidance documents, specifically the *Generic Aging Lessons Learned (GALL) Report* (NUREG-1801) and U.S. Nuclear Regulatory Commission Regulation-1800 (NUREG-1800), *Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants* (SRP-LR) as a basis for determining the adequacy of Aging Management Programs (AMPs). Currently the Nuclear Regulatory Commission (NRC) has approved applications to extend licenses to 60 years for 87 nuclear units with applications for 5 nuclear units currently under review.

On August 29, 2014 the Nuclear Regulatory Commission issued a Staff Requirements Memorandum to provide the NRC staff with direction on SLR, i.e., extending nuclear power plant licenses to 80 years. Consistent with that direction, the NRC drafted guidance documents specifically applicable to SLR applications. In December 2015, 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) were issued for public comment. Following an extensive comment process involving Duke Energy, the nuclear industry, and other stakeholders, the NRC published the final NUREGs in the Federal Register on July 14, 2017, thereby establishing formal regulatory guidance for SLR.

Dominion Energy announced on November 6, 2015 that it would pursue SLR for its Surry plant as a Lead Plant and submitted a letter of intent to the NRC. Exelon Corporation made a similar announcement for its Peach Bottom plant on June 7, 2016. Currently, Exelon is planning to submit the Peach Bottom SLR Application in mid-2018 while Dominion is targeting early- 2019 for Surry. On May 17, 2017 a third utility notified the NRC of its intent to submit an SLR application by the end of 2017. The letter providing the notification was submitted requesting withholding information from public disclosure and as a result the name of the utility and licensee(s) is not publicly available.

Duke Energy is considering Oconee Nuclear Station (ONS) for submission of its first SLR application to extend the licenses to 80 years. The remaining nuclear sites will follow where the cost/benefit proves acceptable.

An Advance Funding was approved on May 12, 2016 for the development portion of the ONS SLR project. These funds are being used to further develop and refine the Project Plan including scope, schedule, cost, risk, and other project elements. At this time, a final decision to extend the ONS or any other Duke Energy nuclear power plants' operating licenses to 80 years has not been made.

d) <u>Combined Heat and Power</u>

Combined Heat and Power systems, also known as cogeneration, generate electricity and useful thermal energy in a single, integrated system. CHP is not a new technology, but an approach to applying existing technologies. Heat that is normally wasted in conventional power generation is recovered as useful energy, which avoids the losses that would otherwise be incurred from separate generation of heat and power. CHP incorporating a 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 good base thermal loads on a regulated Combined Heat and Power 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 are 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 can result in carbon dioxide (CO_2) emission reductions, and is a potential economic development opportunity for the state.

DEC has signed agreements and obtained regulatory approval for a 15 MW CHP at Clemson University, which is expected to be in service by 2020. Filing for a Certificate of Public Convenience and Necessity (CPCN) for a 21 MW CHP at Duke University has been delayed pending the resolution of issues raised by the University. Discussions with other potential steam hosts are currently underway.

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

2020: 43 MW (winter) / 40 MW (summer)
2022: 43 MW (winter) / 40 MW (summer)

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.

e) <u>Resource Adequacy</u>

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, inspect generating plant equipment, and to refuel nuclear plants. Unanticipated mechanical failures may occur at any given time, and 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. The updated study was warranted due to two primary factors.[3] First, the extreme weather

experienced in the service territory in recent winter periods was so impactful to the system that additional review with the inclusion of recent years' weather history was warranted. Second, the system has added, and projects to add, a large amount of solar resources that provide meaningful capacity benefits in the summer but very little capacity benefits in the winter. Solar resources contribute approximately 45% (DEC 46%, DEP 44%) of nameplate capacity at the time of the expected summer peak demand which typically occurs during afternoon hours. However, solar resources only contribute about 5% of nameplate capacity at the time of expected winter peak demand which typically occurs during early morning hours. As discussed in the Renewables section of this document, there is a potential to add significantly to the solar resources already incorporated on the system.

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

[3] Astrapé Consulting is an energy consulting firm with expertise in resource adequacy and integrated resource 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 the summer and winter. However, the incorporation of recent winter load data and the significant amount of solar penetration in the updated study, shows that the majority of loss of load risk is now heavily concentrated during the winter period. Since solar capacity contribution to peak is much greater in the summer compared to the winter, maintaining a summer reserve margin target would result in declining winter reserve margins over time due to the impact on summer versus winter reserves as solar capacity increases.

Thus, use of a summer reserve margin target will no longer ensure that adequate reserve levels are maintained in the winter, and winter load and resources now drive the timing need for new capacity additions. As a result, a winter planning reserve margin target is now needed to ensure that adequate resources are available throughout the year to meet customer demand.

It is noted that the primary driver for the shift to winter capacity planning is the high penetration of solar resources and the associated impact on summer versus winter reserves. Winter load volatility impacts LOLE and puts upward pressure on the reserve margin target; however, winter load volatility or the seasonality of summer versus winter peaks is not the driver for the shift to winter capacity planning.

Results

Based on results of the 2016 resource adequacy assessment, the Company has adopted a 17% minimum winter reserve margin target for scheduling new resource additions. The Company will continue to monitor its generation portfolio and other planning assumptions that can impact resource adequacy and initiate new studies as appropriate.

Adequacy of Projected Reserves

DEC's resource plan reflects winter reserve margins ranging from approximately 17% to 22%. Reserves projected in DEC'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. For example, reserves exceed the 17% minimum target by 3% or more during 2017/2018 through 2019/2020 as a result of the addition of the Lee combined cycle unit in the Fall of 2017 combined with a reduction in the wholesale load forecast beginning 2019. Reserves also exceed the minimum 17% target by 3% or more as a result of resource additions in 2024/2025, 2028/2029 and 2031/2032.

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.

f) <u>Fuel Costs</u>

Similar to the 2015 IRP and the 2016 Biennial IRP Report, the first 10 years of natural gas prices are based on market data and the remaining years are based off of fundamental pricing. Specifically, DEC and DEP are using market based prices for the first 10 years of the planning period (2018 – 2027). Following the 10 years of market prices, the Companies transition to fundamental pricing over a 5 year period with 100% fundamental pricing in 2033 and beyond.

Market prices represent liquid, tradable gas prices offered at the present time, also called "future or forward prices." These prices represent an actual contractually agreed upon price that willing buyers and sellers agree to transact upon at a specified future date. As such, assuming market liquidity, they represent the market's view of prices for a given point in the future. Fundamental prices developed through external econometric modeling, on the other hand, represent a projection of fuel prices into the future taking into account changing supply and demand assumptions in the context of the changing dynamics of the external marketplace. The natural gas market is a liquid market with multiple buyers and sellers of natural gas that are willing to transact at longer transaction terms.

To provide price discovery and demonstrate continued market liquidity, the Company has purchased a fixed price natural gas forward swap for 2,500 million British Thermal Units per day (MMBtu/day) extending nearly ten years forward. It is worth noting that this purchase shows a continued decline in natural gas prices. The 10-year average price for the most recent purchase, executed on August 17, 2017, was lower than a similar purchase made in April of 2017 and lower than the prices used in the development of the 2016 IRP.

As in the 2016 Biennial IRP Report, coal prices continue to be based on 5 years of market data in the 2017 IRP. Following the 5 years of market prices, the Companies' transition to fundamental pricing over a 5-year period with 100% fundamental pricing in 2028.

g) <u>Carbon Assumptions</u>

On August 3, 2015, the EPA finalized a rule establishing CO_2 new source performance standards for pulverized coal (PC) and natural gas combined cycle (NGCC or CC) electric generating units (EGUs) that initiate construction after January 8, 2014. The EPA finalized emission standards of 1,400 lb CO_2 per gross megawatt-hour (MWh) of electricity generation for PC units and 1,000 lb

CO_2 per gross MWh for NGCC units. The standard for PC units can only be achieved with carbon capture and sequestration technology. Numerous parties filed petitions with the U.S. Court of Appeals for the District of Columbia (D.C. Circuit) challenging the EPA's final emission standard for new PC units. Briefing in the case is complete, but oral argument is not currently scheduled. On April 28, 2017, the D.C. Circuit ordered that the litigation be suspended while it considers a motion from EPA to hold the case in abeyance. The court has not ruled on EPA's motion.

In response to a March 28, 2017 Executive Order, the EPA has undertaken a review of the rule to determine whether it should be suspended, revised, or rescinded. The rule remains in effect pending the outcome of litigation and EPA's review of the rule. The EPA has not announced a schedule for completing its review.

On August 3, 2015, the EPA finalized the Clean Power Plan, a rule to limit CO_2 emissions from existing fossil fuel-fired EGUs (existing EGUs are units that commenced construction prior to January 8, 2014). The CPP required states to develop and submit to EPA for approval implementation plans designed to achieve the required CO_2 emission limitations. The CPP required states to submit initial plans by September 6, 2016, and final plans by September 6, 2018. The CPP established two rate-based compliance pathways and two mass-based compliance pathways for states to choose from when developing their state implementation plans. The CPP required emission limitations to take effect beginning in 2022 and get gradually more stringent through 2030.

Numerous legal challenges to the CPP were filed with the D.C. Circuit. On February 9, 2016 the Supreme Court issued a stay in the case, halting implementation of the CPP through any final decision in the case by the Supreme Court. This means the CPP has no legal effect, and EPA cannot enforce any of the deadlines or rule requirements while the stay is in place.

Briefing of the case before the D.C. Circuit was completed in April, 2016. Oral argument before the full D.C. Circuit occurred on September 27, 2016. The D.C. Circuit has not issued a decision in the case. On April 28, 2017, the D.C. Circuit ordered that the litigation be suspended while it considers a motion from EPA to hold the case in abeyance. The court has not ruled on EPA's motion.

In response to the March 28, 2017 Executive Order, EPA initiated a review of the CPP to determine whether it should be suspended, revised, or rescinded. On June 8, 2017, the EPA sent a proposed rule to the Office of Management and Budget to repeal the CPP. Once interagency review is complete, EPA will issue the proposal for public comment. EPA has yet to announce what it will do regarding the possible replacement of the CPP with another rule. There is no schedule for EPA to issue the proposal or to determine what it will do regarding replacement of the CPP.

In light of the uncertainty of future carbon legislation, the Base Case assumes a carbon cost beginning in 2026.

h) Transmission Planned or Under Construction

This section lists the planned transmission line additions and discusses the adequacy of DEC's transmission system. Table 5-E lists the line projects that are planned to meet reliability needs.

Table 4-E: DEC Transmission Line Additions

	Location		Capacity	Voltage	
Year	**From**	**To**	**MVA**	**KV**	**Comments**
2020	Lincoln CTs	Longview Tie	N/A	230	Install new 230/100 kV tie station in existing double circuit line near Maiden, NC

There are presently no new lines, 161 kV and above, under construction in DEC's service area.

DEC Transmission System Adequacy

Duke Energy Carolinas monitors the adequacy and reliability of its transmission system and interconnections through internal analysis and participation in regional reliability groups. Internal transmission planning looks 10 years ahead at available generating resources and projected load to identify transmission system upgrade and expansion requirements. Corrective actions are planned and implemented in advance to ensure continued cost-effective and high-quality service. The DEC transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability. DEC works with DEP, North

Carolina Electric Membership Corporation (NCEMC) and ElectriCities to develop an annual NC Transmission Planning Collaborative (NCTPC) plan for the DEC and DEP systems in both South and North Carolina. In addition, transmission planning is coordinated with neighboring systems including SCE&G and Santee Cooper under a number of mechanisms including legacy interchange agreements between SCE&G, Santee Cooper, DEP, and DEC.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with DEC's Transmission Planning Guidelines for voltage and thermal loading. The annual screening uses methods that comply with SERC Reliability Council (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.

Transmission planning and requests for transmission service and generator interconnection are interrelated to the resource planning process. DEC currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Guidelines and the Federal Energy Regulatory Commission (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.

SERC audits DEC every three years for compliance with NERC Reliability Standards. Specifically, the audit requires DEC to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the Company's annual compliance filing certifications. SERC conducted a NERC Reliability Standards compliance audit of DEC in December 2016. The scope of this audit included standards impacting the Transmission Planning area. DEC received "No Findings" from the audit team in the Transmission Planning area.

DEC participates in a number of regional reliability groups to coordinate analysis of regional, sub-regional and inter-balancing authority area transfer capability and interconnection reliability. The reliability groups' purpose is to:

- Assess the interconnected system's capability to handle large firm and non-firm transactions for purposes of economic access to resources and system reliability;

- Ensure that planned future transmission system improvements do not adversely affect neighboring systems; and

- Ensure interconnected system compliance with NERC Reliability Standards.

Regional reliability groups evaluate transfer capability and compliance with NERC Reliability Standards for the upcoming peak season and five- and ten-year periods. The groups also perform computer simulation tests for high transfer levels to verify satisfactory transfer capability.

Application of the practices and procedures described above have ensured DEC's transmission system is expected to continue to provide reliable service to its native load and firm transmission customers.

5. LOAD FORECAST:

Methodology

The Duke Energy Carolinas Spring 2017 Forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2018 – 2032 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, and industrial production indices, along with weather and appliance efficiency trends. Population projections are used in the Residential customer model.

The economic projections used in the Spring 2017 Forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the Carolinas.

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 variables such as weather, regional economic and demographic trends, electric prices, and efficiency trends.

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 Agency (EIA) data. It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models. The outlook for usage per customer is slightly negative through much of the forecast horizon, so most of the growth in sales is related to customer (population) increases. The projected growth rate of the Residential class after considering all impacts (i.e., customer growth, energy efficiency, behind-the-meter solar, etc.) is 0.9% for the period 2018-2032.

The Commercial forecast also uses a 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. The projected growth rate of commercial in the Spring 2017 Forecast after considering all impacts, is 0.2% for the period 2018 to 2032.

The Industrial class is forecasted using a standard econometric model, with drivers such as industrial production and the price of electricity. Overall, Industrial sales are expected to grow 0.5% over the forecast horizon, after all impacts.

System peak demands were projected using the SAE approach in the Spring 2017 Forecast. The peak forecast was developed using a monthly SAE model, similar to the sales SAE models, which includes monthly appliance saturations and efficiencies, interacted with weather and the fraction of each appliance type that is in use at the time of the monthly peak. Over the forecast period, the summer peak demand is expected to grow 0.4% (after all impacts), while the winter peak demand is growing 0.9% (after all impacts).

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.

Forecast Enhancements

In 2013, The Company began using the statistically adjusted end use models (SAE) provided by ITRON 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 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. 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 Spring 2017 forecast utilizes:

- Moody's Analytics January 2017 base economic projections.

- End use equipment and appliance indexes reflect the 2016 update of ITRON's end-use data, which is consistent with the Energy Information Administration's 2016 Annual Energy Outlook.
- A calculation of normal weather using the period 1987-2016.

Additional focus is being placed on the hourly shaping of sales, which plays a critical role in forecasting summer and winter peaks. While much of this work is ongoing and will be incorporated in the 2018 IRP's we continue to review the weather sensitivity of winter and summer peaks, as well as the hourly shaping of behind-the-meter solar, UEE, electric vehicles, and other variables.

Additional focus is also being placed on Duke's load research sample data, to gain a better understanding of historical hourly demand trends, winter and summer peaking characteristics by customer class, and minimums by customer class, in our continuous effort to improve forecast accuracy.

<u>Assumptions</u>

Below are the projected average annual growth rates of several key drivers from DEC's Spring 2017 Forecast.

	2018-2032
Real Income	2.7%
Manufacturing Industrial Production Index (IPI)	1.3%
Population	1.6%

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

Wholesale

The wholesale contracts are included in the forecasted sales and peaks in the following tables. Please note that Duke is expected to lose a portion of wholesale load in support of NTE Energy (Kings Mountain combined cycle) resource. For a complete description of the Wholesale forecast, please see Chapter 11.

Historical Values

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

In tables 5-A & 5-B below the history of DEC customers and actual sales are given.

Table 5-A Retail Customers (Thousands, Annual Average)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Avg Annual Growth Rate
Residential	1,916	2,012	2,024	2,034	2,041	2,053	2,068	2,089	2,117	2,148	**1.3%**
Commercial	322	334	331	333	335	337	339	342	345	349	**0.9%**
Industrial	7	7	7	7	7	7	7	7	6	6	**-1.0%**
Other	13	14	14	14	14	14	14	15	15	15	**1.8%**
Total	2,258	2,367	2,376	2,388	2,397	2,411	2,428	2,453	2,483	2,519	**1.2%**

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

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Avg Annual Growth Rate
Residential	27,459	27,335	27,273	30,049	28,323	26,279	26,895	27,976	27,916	27,939	0.3%
Commercial	27,433	27,288	26,977	27,968	27,593	27,476	27,765	28,421	28,700	28,906	0.6%
Industrial	23,948	22,634	19,204	20,618	20,783	20,978	21,070	21,577	22,136	21,942	-0.8%
Other	278	284	287	287	287	290	293	303	305	304	1.0%
Total Retail	79,118	77,541	73,741	78,922	76,986	75,023	76,023	78,277	79,057	79,091	0.1%
Wholesale	2,454	3,525	3,788	5,166	4,866	5,176	5,824	6,559	6,916	7,614	14.3%
Total System	81,572	81,066	77,529	84,088	81,852	80,199	81,847	84,836	85,973	86,705	0.7%

Note the values in Table 5-B are not weather adjusted.

Utility Energy Efficiency

UEE continues to have a large impact in the acceleration of the adoption of energy efficiency. When including the energy and peak impacts of UEE, 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 7 years before the energy reduction program would have been otherwise adopted, then the UEE effects after year 7 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.

Table 5-C below illustrates this process:

- Column A: Total energy before reduction of future UEE
- Column B: Historical UEE Roll-Off
- Column C: Forecasted UEE Incremental Roll-On
- Column D: Forecasted UEE Incremental Roll-Off
- Column E: UEE amount to subtract from Column A
- Column F: Total energy after incorporating UEE (column A less column E)

Table 5-C UEE Program Life Process (GWh)

	Forecast Before UEE	Historical UEE Roll Off	Forecasted UEE Incremental Roll on	Forecasted UEE Incremental Roll Off	UEE to Subtract From Forecast	Forecast After UEE
2017	95,326	0	422	0	422	94,903
2018	96,506	9	777	0	786	95,739
2019	96,269	37	1,134	0	1,172	95,172
2020	97,251	95	1,482	0	1,576	95,864
2021	98,121	193	1,820	0	2,013	96,495
2022	98,589	328	2,157	0	2,484	96,761
2023	99,470	484	2,496	4	2,984	97,461
2024	100,395	646	2,815	9	3,469	98,234
2025	101,169	790	3,127	24	3,941	98,856
2026	102,005	901	3,460	66	4,428	99,513
2027	102,814	981	3,898	105	4,984	100,001
2028	103,613	1,029	4,764	527	6,321	100,405
2029	104,214	1,054	6,696	2,144	9,895	100,716
2030	104,733	1,066	7,018	2,250	10,335	101,032
2031	105,287	1,070	7,288	2,338	10,697	101,407
2032	105,871	1,070	7,511	2,410	10,991	101,840

Results

A tabulation of the utility's forecasts for 2018-2032, including peak loads for summer and winter seasons of each year and annual energy forecasts, both with and without the impact of UEE programs, are shown below in Tables 5-F and 5-G.

Load duration curves, with and without UEE programs, follow Tables 5-F and 5-G, and are shown as Charts 5-A and 5-B.

The tables below show the results of the forecast:

- Table 5-D: Total retail customers by class
- Table 5-E: Retail sales (at the meter) after the impacts of energy efficiency
- Table 5-F: Forecasted system summer peak, winter peak, and sales – ***before*** including the impact of utility sponsored energy efficiency programs (at generation)
- Chart 5-A: Load duration curve – ***before*** including the impact of utility sponsored energy efficiency programs

- Table 5-G: Forecasted system summer peak, winter peak, and sales – ***after*** including the impact of utility sponsored energy efficiency programs (at generation)
- Chart 5-B: Load duration curve – ***after*** including the impact of utility sponsored energy efficiency programs

Table 5-D Retail Customers (Thousands, Annual Average)

	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2018	2,198	356	6	15	2,576
2019	2,220	359	6	16	2,601
2020	2,243	362	6	16	2,627
2021	2,266	365	6	16	2,652
2022	2,289	367	6	16	2,678
2023	2,312	370	6	16	2,704
2024	2,335	374	6	16	2,731
2025	2,359	376	6	17	2,758
2026	2,383	379	6	17	2,785
2027	2,407	382	6	17	2,812
2028	2,432	385	6	17	2,839
2029	2,457	388	6	17	2,867
2030	2,481	391	5	17	2,895
2031	2,507	394	5	18	2,924
2032	2,532	397	5	18	2,953
Avg. Annual Growth Rate	1.0%	0.8%	-0.8%	1.0%	1.0%

Table 5-E Retail Sales (GWh Sold - Years Ended December 31)

	Residential	Commercial	Industrial	Other	Retail
	Gwh	Gwh	Gwh	Gwh	Gwh
2018	27,702	28,564	22,368	299	78,933
2019	27,773	28,631	22,608	297	79,310
2020	27,945	28,717	22,927	294	79,884
2021	28,138	28,747	23,253	291	80,429
2022	28,372	28,805	23,425	288	80,891
2023	28,650	28,904	23,646	286	81,486
2024	28,950	29,053	23,847	285	82,135
2025	29,240	29,139	24,009	283	82,671
2026	29,540	29,267	24,135	280	83,222
2027	29,823	29,347	24,157	278	83,605
2028	30,103	29,422	24,092	277	83,895
2029	30,367	29,435	24,035	276	84,113
2030	30,649	29,403	24,004	274	84,331
2031	30,946	29,390	23,993	273	84,602
2032	31,255	29,421	23,964	272	84,912
Avg. Annual Growth Rate	0.9%	0.2%	0.5%	-0.7%	0.5%

Table 5-F Load Forecast without Energy Efficiency Programs (at Generation)

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2018	18,953	18,770	96,515
2019	18,908	18,818	96,306
2020	19,109	19,033	97,346
2021	19,267	19,230	98,314
2022	19,368	19,409	98,917
2023	19,531	19,639	99,954
2024	19,690	19,908	101,041
2025	19,860	20,088	101,959
2026	20,060	20,324	102,907
2027	20,250	20,548	103,795
2028	20,416	20,800	104,643
2029	20,561	21,006	105,268
2030	20,685	21,199	105,799
2031	20,834	21,388	106,357
2032	20,970	21,616	106,941
Avg. Annual Growth Rate	0.7%	1.0%	0.7%

Note: Table 7-A differs from these values due to a 47 MW PMPA backstand contract through 2020.

Chart 5-A Load Duration Curve without Energy Efficiency Programs (at Generation)

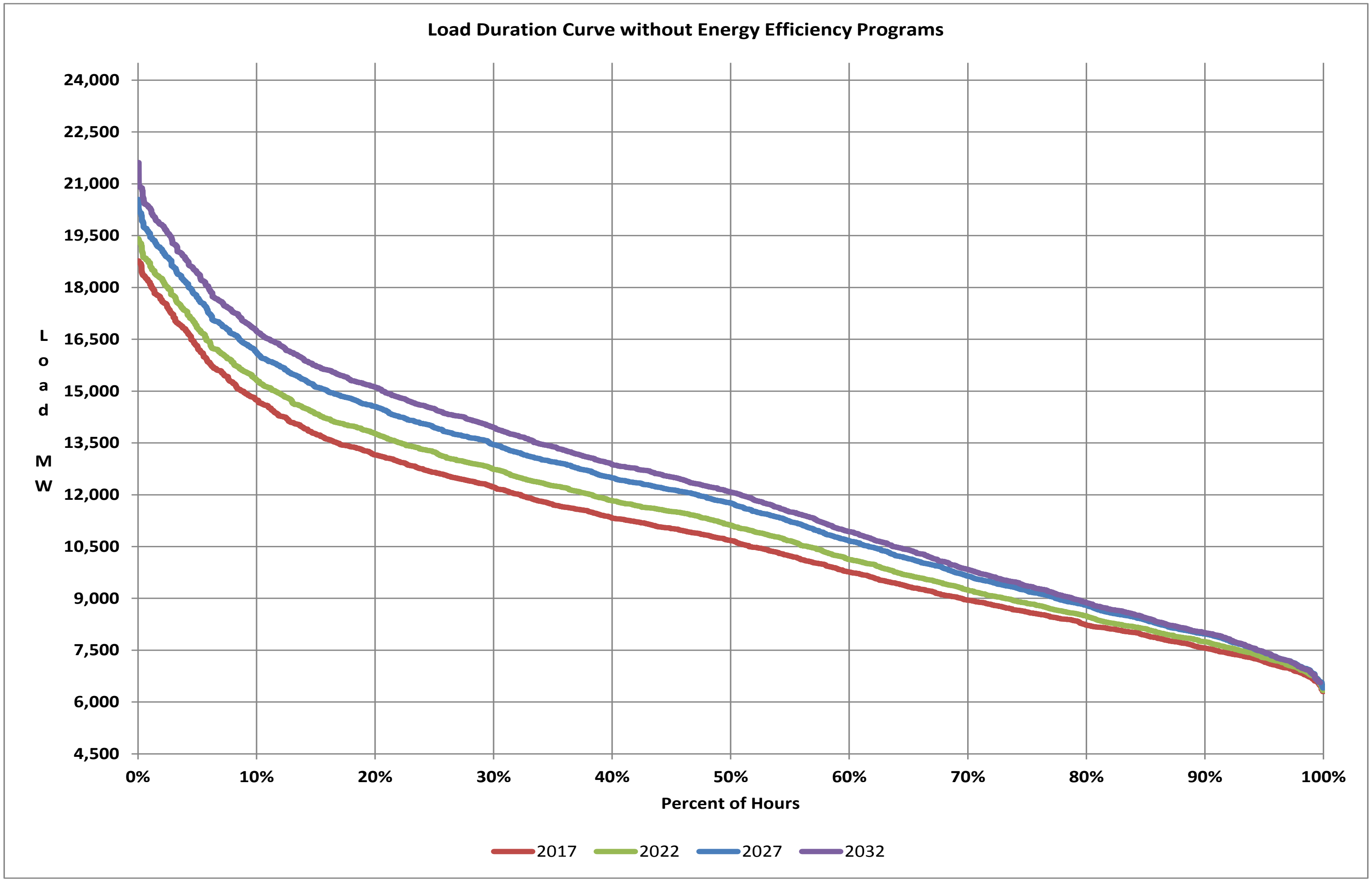
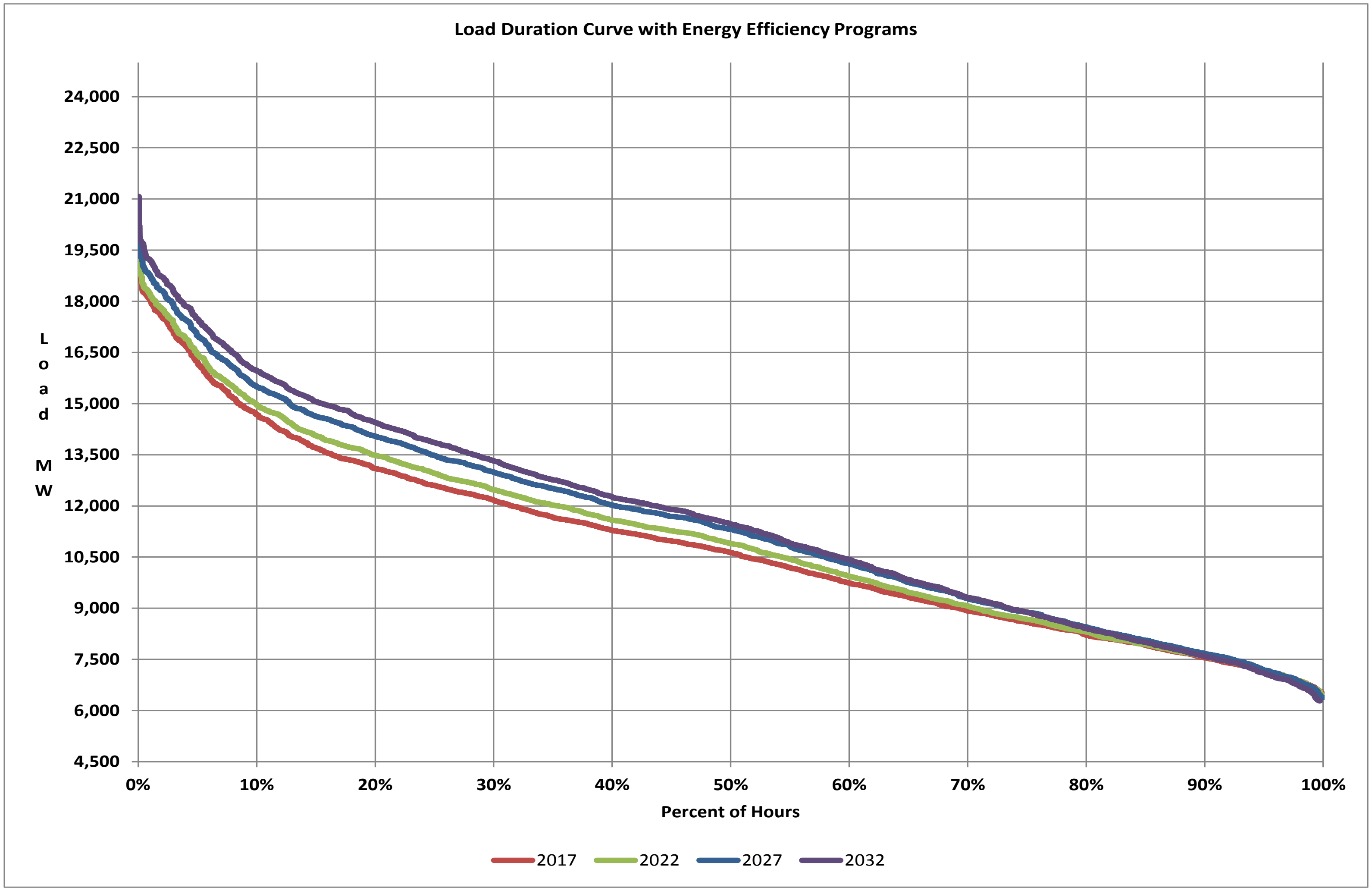


Table 5-G Load Forecast with Energy Efficiency Programs (at Generation)

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2018	18,786	18,687	95,739
2019	18,655	18,714	95,172
2020	18,776	18,892	95,864
2021	18,854	19,055	96,495
2022	18,877	19,182	96,761
2023	18,961	19,376	97,461
2024	19,047	19,612	98,234
2025	19,147	19,761	98,856
2026	19,277	19,965	99,513
2027	19,381	20,146	100,001
2028	19,457	20,349	100,405
2029	19,530	20,519	100,716
2030	19,601	20,690	101,032
2031	19,701	20,859	101,407
2032	19,797	21,073	101,840
Avg. Annual Growth Rate	0.4%	0.9%	0.4%

Note: Table 7-A differs from these values due to a 47 MW PMPA backstand contract through 2020.

Chart 5-B Load Duration Curve with Energy Efficiency Programs (at Generation)



6. ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT:

Current Energy Efficiency and Demand-Side Management Programs

DEC uses EE and DSM programs in its IRP to efficiently and cost-effectively alter customer demands and reduce the long-run supply costs for energy and peak demand. These programs can vary greatly in their dispatch characteristics, size and duration of load response, certainty of load response, and level and frequency of customer participation. In general, programs are offered in two primary categories: EE programs that reduce energy consumption and DSM programs that reduce peak demand (demand-side management or demand response programs and certain rate structure programs). Following are the EE and DSM programs available through DEC as of December 31, 2016:

Residential Customer Programs

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

Non-Residential Customer Programs

- Non-Residential Smart $aver® Energy Efficient Food Service Products Program
- Non-Residential Smart $aver® Energy Efficient HVAC Products Program
- Non-Residential Smart $aver® Energy Efficient IT Products Program
- Non-Residential Smart $aver ®Energy Efficient Lighting Products Program
- Non-Residential Smart $aver® Energy Efficient Process Equipment Products Program
- Non-Residential Smart $aver® Energy Efficient Pumps and Drives Products Program
- Non-Residential Smart $aver® Custom Program
- Non-Residential Smart $aver® Custom Energy Assessments Program
- Small Business Energy Saver
- Smart Energy in Offices
- Business Energy Report Pilot
- PowerShare®

- PowerShare® CallOption
- 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[4]) since the inception of these existing programs through the end of 2016 are summarized below. Please note that the cumulative impacts listed below include the impact of any Measurement and Verification performed since program inception and also note that a "Participant" in the information included below is based on the unit of measure for specific energy efficiency measure (e.g. number of bulbs, kWh of savings, tons of refrigeration, etc.), and may not be the same as the number of customers that actually participate in these programs. The following provides more detail on DEC's existing EE programs:

Residential Programs

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

The implementation vendor for this program abruptly discontinued operations in November 2015. Subsequent participation reflects continued support to those customers with canceled appointments, as well as any participation uploads not previously recorded by the vendor. Future potential impacts associated with this program beyond 2016 are not included in this IRP analysis.

Appliance Recycling			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2016	31,090	31,867	4,355

[4] "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.

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, 2016	79,099	57,104	8,996

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

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

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

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

Energy Efficiency Education			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2016	158,677	39,150	7,028

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

- Energy Efficient Pool Equipment: This measure encourages the purchase and installation of energy efficient equipment and controls. Initially, the measure will focus on variable speed pumps, but the pool equipment offerings may evolve with the marketplace to include additional equipment options and control devices that reduce energy consumption and/or demand.
- Energy Efficient Lighting: This measure encourages the installation of energy efficient lighting products and controls. The product examples may include, but are not limited to the following: standard compact fluorescent light bulbs (CFLs), specialty CFLs, A lamp light emitting diodes (LEDs), specialty LEDs, CFL fixtures, LED fixtures, 2X incandescent, LED holiday lighting, motion sensors, photo cells, timers, dimmers and daylight sensors.
- Energy Efficient Water Heating and Usage: This measure encourages the adoption of heat pump water heaters, insulation, temperature cards and low flow devices.

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

Residential Smart $aver® Program – Residential CFLs			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2016	31,413,573	1,267,684	135,650

Energy Efficient Appliances and Devices Program - Residential LEDs			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2016	1,947,739	65,182	8,443

Energy Efficient Appliances and Devices Program – Retail Lighting			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2016	1,082,612	32,679	3,985

Residential Smart $aver® Program – Specialty Lighting			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2016	1,604,103	69,630	8,464

Residential Smart $aver® Program – Water Measures			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2016	835,295	65,119	6,352

Residential Smart $aver® Program – Pool Equipment			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2016	1,057	2,630	662

Heating, Ventilation, and Air Conditioning (HVAC) Energy Efficiency Program (formerly part of Residential Smart $aver® program) provides residential customers with opportunities to lower their home's electric use through maintenance and improvements to their central HVAC system(s) as well as the structure of their home's building envelope and duct system(s). This program reaches Duke Energy Carolinas customers during the decision-making process for measures included in the program. The prescriptive and a-la-carte design of the program allows customers to implement individual, high priority measures in their homes without having to commit to multiple measures and higher price tags. A referral channel provides free, trusted referrals to customers seeking reliable, qualified contractors for their energy saving home improvement needs. The measures eligible for incentives through the program are:

- Central Air Conditioner
- Heat Pump
- Attic Insulation and Air Sealing
- Duct Sealing
- Duct Insulation
- Central Air Conditioner Tune Up
- Heat Pump Tune Up
- HVAC Quality Installation
- Smart Thermostat

Residential Smart $aver® – HVAC			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2016	90,262	62,103	19,338

Residential Smart $aver® – Tune and Seal			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2016	3,042	2,048	621

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

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

Residential Smart $aver® – Property Manager CFLs			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2016	1,184,195	51,014	5,217

Multi-Family Energy Efficiency Program – Property Manager LEDs			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2016	19,344	775	86

Residential Smart $aver® – Multi Family Water Measures			
Cumulative as of:	Number of Participants	Gross Savings (at plant)	
		MWh Energy	Peak kW
December 31, 2016	370,746	30,424	2,855

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

An interactive online portal was introduced in 2016, allowing 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.

My Home Energy Report			
	Number of	Gross Savings (at plant)	
Capability as of:	Participants	MWh Energy	Peak kW
December 31, 2016	1,202,664	283,570	71,814

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

- Neighborhood Energy Saver (NES) is available only to individually-metered residences served by Duke Energy Carolinas in neighborhoods selected by the Company, which are considered low-income based on third party and census data, which includes income level and household size. Neighborhoods targeted for participation in this program will typically have approximately 50% or more of the households with income below 200% of the poverty level established by the U.S. Government. This approach allows the Company to reach a larger audience of low income customers than traditional government agency flow-through methods. The program provides customers with the direct installation of measures into the home to increase the EE and comfort level of the home. Additionally, customers receive EE education to encourage behavioral changes for managing energy usage and costs.
- The Company recognizes the existence of customers whose EE needs surpass the standard low cost measure offerings provided through NES. In order to accommodate customers needing this more substantial assistance, the Company will also offer the following two programs that are deployed in conjunction with the existing government-funded North Carolina Weatherization Assistance Program when feasible. Collaborating with these programs will result in a reduction of overhead and administration costs.

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

Income Qualified Energy Efficiency and Weatherization			
	Number of	Gross Savings (at plant)	
Cumulative as of:	Participants	MWh Energy	Peak kW
December 31, 2016	42,217	19,292	3,121

Non-Residential

The Non-Residential Smart $aver® programs are listed separately below by technology but for the purpose of reporting the historical performance, all of the historical impacts are combined into a single Non-Residential Smart $aver® total.

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

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

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

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

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

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

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

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

Non-Residential Smart $aver®			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2016	11,490,953	1,579,910	253,454

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

Small Business Energy Saver			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2016	137,803,781	162,709	30,620

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

Smart Energy in Offices			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2016	113,307,711	120,354	25,049

In addition, the impacts from the Smart Energy Now Pilot program are included below:

Smart Energy Now Pilot			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2015	70	25,093	804

<u>Pilot</u>

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

Business Energy Report Pilot			
	Number of	**Gross Savings (at plant)**	
Cumulative as of:	**Participants**	**MWh Energy**	**Peak kW**
December 31, 2016	14,947	5,561	388

With the cost effectiveness of the program expected to decline below the allowable threshold, the program was terminated in 2017.

Demand Side Management Programs

DEC's current DSM programs will be presented in two sections: Demand Response Direct Load Control Programs and Demand Response Interruptible Programs and Related Rate Tariffs.

Demand Response – Direct Load Control Programs

These programs can be dispatched by the utility and have the highest level of certainty due to the participant not having to directly respond to an event. DEC's current direct load control programs are:

Residential

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

Power Manager® provides DEC with the ability to reduce and shift peak loads, thereby enabling a corresponding deferral of new supply-side peaking generation and enhancing system reliability.

Participating customers are impacted by (1) the installation of load control equipment at their residence, (2) load control events which curtail the operation of their air conditioning unit for a period of time each hour, and (3) the receipt of bill credits from DEC in exchange for allowing DEC the ability to control their electric equipment.

Power Manager®			
Cumulative as of:	**Participants (Customers)**	**Devices (Switches)**	**Summer 2016 Capability (MW)**
December 31, 2016	195,804	233,007	446

The following table shows Power Manager® program activations that were not for testing purposes from June 1, 2015 through December 31, 2016.

Power Manager® Program Activations*			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
June 16, 2015 – 2:30 PM	June 16, 2015 – 6:00 PM	210	228
June 23, 2015 – 2:30 PM	June 23, 2015 – 6:00 PM	210	228
July 20, 2015 – 3:30 PM	July 20, 2015 – 6:00 PM	150	168
August 5, 2015 – 2:30 PM	August 5, 2015 – 6:00 PM	210	232
June 23, 2016 – 2:30 PM	June 23, 2016 – 5:00 PM	150	219
July 14, 2016 – 2:30 PM	July 14, 2016 – 6:00 PM	210	228
September 8, 2016 – 3:30 PM	September 8, 2016 – 6:00 PM	150	180
September 19, 2016 – 2:30 PM	September 19, 2016 – 6:00 PM	210	150

Non-Residential

Demand Response – Interruptible Programs and Related Rate Structures

These programs rely either on the customer's ability to respond to a utility-initiated signal requesting curtailment, or on rates with price signals that provide an economic incentive to reduce or shift load. Timing, frequency, and nature of the load response depend on customers' actions after notification of an event or after receiving pricing signals. Duke Energy Carolinas' current interruptible and time-of-use rate programs include:

Interruptible Power Service (IS) (North Carolina Only) **-** Participants agree contractually to reduce their electrical loads to specified levels upon request by DEC. If customers fail to do so during an interruption, they receive a penalty for the increment of demand exceeding the specified level.

Interruptible Power Service		
Cumulative as of:	**Participants**	**Summer 2016 Capability (MW)**
December 31, 2016	51	125

The following table shows IS program activations that were not for testing purposes from July 1, 2015 through December 31, 2016.

IS Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
July 13, 2016 – 4:30 pm	July 13, 2016 – 7:00 pm	150	125
July 14, 2016 – 2:00 pm	July 14, 2016 – 7:00 pm	300	125
July 25, 2016 – 2:00 pm	July 25, 2016 – 8:00 pm	360	121
July 26, 2016 – 2:00 pm	July 26, 2016 – 8:00 pm	360	121

Standby Generator Control (SG) (North Carolina Only) **-** Participants agree contractually to transfer electrical loads from the DEC source to their standby generators upon request of the Company. The generators in this program do not operate in parallel with the DEC system and therefore, cannot "backfeed" (i.e., export power) into the DEC system.

Participating customers receive payments for capacity and/or energy, based on the amount of capacity and/or energy transferred to their generators.

Standby Generator Control (SG)		
Cumulative as of:	**Participants**	**Summer 2016 Capability (MW)**
December 31, 2016	25	15

The following table shows SG program activations that were <u>not</u> for testing purposes from July 1, 2015 through December 31, 2016.

SG Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
July 13, 2016 – 4:30 pm	July 13, 2016 – 7:00 pm	150	15
July 14, 2016 – 2:00 pm	July 14, 2016 – 7:00 pm	300	15
July 25, 2016 – 2:00 pm	July 25, 2016 – 8:00 pm	360	15
July 26, 2016 – 2:00 pm	July 26, 2016 – 8:00 pm	360	15

PowerShare® is a non-residential curtailment program consisting of four options: an emergency only option for curtailable load (PowerShare® Mandatory), an emergency only option for load curtailment using on-site generators (PowerShare® Generator), an economic based voluntary option (PowerShare® Voluntary) and a combined emergency and economic option that allows for increased notification time of events (PowerShare® CallOption).

PowerShare® Mandatory: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail during utility-initiated emergency events. Participants also receive energy credits for the load curtailed during events. Customers enrolled may also be enrolled in PowerShare® Voluntary and eligible to earn additional credits.

PowerShare® Mandatory		
Cumulative as of:	**Participants**	**Summer 2016 Capability (MW)**
December 31, 2016	170	339

The following table shows PowerShare® Mandatory program activations that were <u>not</u> for testing purposes from July 1, 2015 through December 31, 2106.

PowerShare® Mandatory Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
July 13, 2016 – 4:30 pm	July 13, 2016 – 7:00 pm	150	331
July 14, 2016 – 2:00 pm	July 14, 2016 – 7:00 pm	300	331
July 25, 2016 – 2:00 pm	July 25, 2016 – 8:00 pm	360	314
July 26, 2016 – 2:00 pm	July 26, 2016 – 8:00 pm	360	315

PowerShare® Generator: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail (i.e. transfer to their on-site generator) during utility-initiated emergency events and their performance during monthly test hours. Participants also receive energy credits for the load curtailed during events.

PowerShare® Generator Statistics		
As of:	**Participants**	**Summer 2016 Capability (MW)**
December 31, 2016	13	12

The following table shows PowerShare® Generator program activations that were not for testing purposes from July 1, 2015 through December 31, 2016.

PowerShare® Generator Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
July 13, 2016 – 4:30 pm	July 13, 2016 – 7:00 pm	150	12
July 14, 2016 – 2:00 pm	July 14, 2016 – 7:00 pm	300	12
July 25, 2016 – 2:00 pm	July 25, 2016 – 8:00 pm	360	12
July 26, 2016 – 2:00 pm	July 26, 2016 – 8:00 pm	360	12

PowerShare® Voluntary: Enrolled customers will be notified of pending emergency or economic events and can log on to a website to view a posted energy price for that particular event. Customers will then have the option to participate in the event and will be paid the posted energy credit for load curtailed. Since this is a voluntary event program, no capacity benefit is recognized for this program and no capacity incentive is provided. The values below represent participation in PowerShare® Voluntary only and do not double count the participants in PowerShare® Mandatory that also participate in PowerShare® Voluntary.

PowerShare® Voluntary		
As of:	**Participants**	**Summer 2016 Capability (MW)**
December 31, 2016	3	N/A

The following table shows PowerShare® Voluntary program activations that were not for testing purposes from July 1, 2015 through December 31, 2016.

PowerShare® Voluntary Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
July 13, 2016 – 4:30 pm	July 13, 2016 – 7:00 pm	150	0
July 14, 2016 – 2:00 pm	July 14, 2016 – 7:00 pm	300	0
July 25, 2016 – 2:00 pm	July 25, 2016 – 8:00 pm	360	0
July 26, 2016 – 2:00 pm	July 26, 2016 – 8:00 pm	360	0

PowerShare® CallOption: This program offers a participating customer the ability to receive credits when the customer agrees, at the Company's request, to reduce and maintain its load by a minimum of 100 kW during Emergency and/or Economic Events. Credits are paid for the load available for curtailment, and charges are applicable when the customer fails to reduce load in accordance with the participation option it has selected. Participants are obligated to curtail load during emergency events. CallOption offers four participation options to customers: PS 0/5, PS 5/5, PS 10/5 and PS 15/5. All options include a limit of five Emergency Events and set a limit for Economic Events to 0, 5, 10 and 15 respectively.

PowerShare® CallOption		
As of:	**Participants**	**Summer 2016 Capability (MW)**
December 31, 2016	0	0

The PowerShare® CallOption program was not activated during the period from July 1, 2015 through December 31, 2016.

PowerShare® CallOption 200: This CallOption offering is targeted at customers with very flexible load and curtailment potential of up to 200 hours of economic load curtailment each year. This option will function essentially in the same manner as the Company's other CallOption offers. However, customers who participate would experience considerably more requests for load curtailment for economic purposes. Participants remain obligated to curtail load during up to 5 emergency events.

PowerShare® CallOption 200 Program		
As of:	**Participants**	**Summer 2016 Capability (MW)**
December 31, 2016	0	0

The PowerShare® CallOption 200 program was not activated during the period from July 1, 2015 through December 31, 2016.

EnergyWise℠ for Business: is both an energy efficiency and demand response program for non-residential customers that allows DEC 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, DEC 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 DEC. 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 the upcoming conservation periods.

The DEC EnergyWise^{SM} for Business program was implemented in South Carolina in December 2015, followed by North Carolina in January 2016.

EnergyWise^{SM} for Business Program				
		MW Capability		MWh Energy Savings (at plant)
Cumulative as of:	Participants*	Summer	Winter	
December 31, 2016	1,144	3.9	0.4	1,668

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

All DEC EnergyWise^{SM} for Business program activations in 2016 were for testing purposes.

Future EE and DSM Programs

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

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

EE and DSM Program Screening

The Company uses the DSMore model to evaluate the costs, benefits, and risks of EE and DSM programs and measures. DSMore is a financial analysis tool designed to estimate of the capacity and energy values of EE and DSM measures at an hourly level across distributions of weather conditions and/or energy costs or prices. By examining projected program performance and cost effectiveness over a wide variety of weather and cost conditions, the Company is in a better position to measure the risks and benefits of employing EE and DSM measures versus traditional generation capacity additions, and further, to ensure that DSM resources are compared to supply side resources on a level playing field.

The analysis of energy efficiency and demand side management cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: Utility Cost Test (UCT), Rate Impact Measure Test (RIM), Total Resource Cost (TRC) Test and Participant Test. DSMore provides the results of those tests for any type of EE or DSM program.

- The UCT compares utility benefits (avoided costs) to the costs incurred by the utility to implement the program, and does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs, and load (line) losses.
- The RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program.
- The TRC Test compares the total benefits to the utility and to participants relative to the costs to the utility to implement the program along with the costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test, however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC.
- The Participant Test evaluates programs from the perspective of the program's participants. The benefits include reductions in utility bills, incentives paid by the utility and any State, Federal or local tax benefits received.

The use of multiple tests can ensure the development of a reasonable set of cost-effective DSM and EE programs and indicate the likelihood that customers will participate.

Energy Efficiency and Demand-Side Management Program Forecasts

Forecast Methodology

In 2016, DEC commissioned a new EE market potential study to obtain new estimates of the technical, economic and achievable potential for EE savings within the DEC service area. The final reports (one for North Carolina and one for South 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 DEC program managers and EE planners, feedback from the DSM Collaborative and with the possible assistance of implementation contractors.

The Nexant market potential study included projections of Energy Efficiency impacts over a 25-year period for years 2017-2041. Additionally, the cumulative savings projections for both scenarios 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 Base Case projected MWh load impacts of all DEC EE programs implemented since the approval of the save-a-watt recovery mechanism in 2009 on a Net of Free Riders basis. The Company assumes total EE savings will continue to grow on an annual basis throughout the planning period, however, the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan. Please note that this table includes a column that shows historical EE program savings since the inception of the EE programs in 2009 through the end of 2016, which accounts for approximately an additional 3,552 gigawatt-hour (GWh) of net energy savings.

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

Projected MWh Impacts of EE Programs

Year	Annual MWh Load Reduction - Net	
	Including measures added in 2017 and beyond	Including measures added since 2009
2009-16		3,551,914
2017	357,087	3,909,001
2018	709,635	4,261,549
2019	1,072,442	4,624,356
2020	1,408,628	4,960,542
2021	1,750,681	5,302,596
2022	2,101,371	5,653,285
2023	2,458,459	6,010,373
2024	2,821,185	6,373,099
2025	3,184,851	6,736,765
2026	3,554,434	7,106,348
2027	3,927,001	7,478,915
2028	4,305,478	7,857,392
2029	4,686,614	8,238,528
2030	5,071,468	8,623,382
2031	5,461,551	9,013,465
2032	5,859,226	9,411,140

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

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

Projected MW Load Impacts of DSM Programs

	Summer Peak MW Reduction					
Year	IS	SG	PowerShare	PowerManager	EnergyWise for Business	Total Annual Peak
2018	101	10	348	506	16	981
2019	96	9	359	519	24	1,007
2020	92	9	369	530	33	1,033
2021	87	8	380	541	41	1,058
2022	84	8	385	541	49	1,066
2023	82	8	385	541	49	1,065
2024	82	8	385	541	49	1,065
2025	82	8	385	541	49	1,065
2026	82	8	385	541	49	1,065
2027	82	8	385	541	49	1,065
2028	82	8	385	541	49	1,065
2029	82	8	385	541	49	1,065
2030	82	8	385	541	49	1,065
2031	82	8	385	541	49	1,065
2032	82	8	385	541	49	1,065

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

Programs Evaluated but Rejected

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

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

Duke Energy Carolinas is no longer evaluating an Integrated Volt-Var Control project at this time.

7. DEVELOPMENT OF THE RESOURCE PLAN:

The following section details the Company's expansion plan and resource mix that is required to meet the needs of DEC's customers over the next 15 years. The section also includes a discussion of the various technologies considered during the development of the IRP, as well as, a summary of the resources required in the four cases that were considered in this IRP.

Tables 7-A and 7-B represent the winter and summer Load, Capacity, and Reserves tables for the Base Case.

Table 7-A Load, Capacity and Reserves Table - Winter

Winter Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2017 Annual Plan

		17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32
Load Forecast																
1	Duke System Peak	18,817	18,865	19,080	19,230	19,409	19,639	19,908	20,088	20,324	20,548	20,800	21,006	21,199	21,388	21,616
2	Firm Sale	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Cumulative New EE Programs	(83)	(104)	(141)	(175)	(227)	(263)	(296)	(328)	(359)	(402)	(451)	(487)	(510)	(529)	(543)
4	**Adjusted Duke System Peak**	**18,734**	**18,761**	**18,939**	**19,055**	**19,182**	**19,376**	**19,612**	**19,761**	**19,965**	**20,146**	**20,349**	**20,519**	**20,690**	**20,859**	**21,073**
Existing and Designated Resources																
5	Generating Capacity	21,216	21,899	21,909	21,915	21,961	22,008	22,054	22,101	21,899	21,899	21,899	21,899	21,373	21,373	21,200
6	Designated Additions / Uprates	683	10	6	46	46	46	46	402	-	-	-	-	-	-	-
7	Retirements / Derates	-	-	-	-	-	-	-	(604)	-	-	-	(526)	-	(173)	-
8	**Cumulative Generating Capacity**	**21,899**	**21,909**	**21,915**	**21,961**	**22,008**	**22,054**	**22,101**	**21,899**	**21,899**	**21,899**	**21,899**	**21,373**	**21,373**	**21,200**	**21,200**
Purchase Contracts																
9	**Cumulative Purchase Contracts**	**271**	**239**	**239**	**157**	**156**	**154**	**154**	**153**	**148**	**148**	**146**	**132**	**132**	**70**	**61**
	Non-Compliance Renewable Purchases	56	55	58	63	68	68	68	68	63	62	62	62	62	62	61
	Non-Renewables Purchases	215	184	182	95	88	86	86	85	85	85	83	70	70	8	-
Undesignated Future Resources																
10	Nuclear															1,117
11	Combined Cycle								1,282				1,282			
12	Combustion Turbine															
13	Solar															
Renewables																
13	**Cumulative Renewables Capacity**	110	122	125	139	134	174	193	194	190	186	188	187	184	177	172
14	**Combined Heat & Power**	-	-	43	-	43	-	-	-	-	-	-	-	-	-	-
15	**Cumulative Production Capacity**	**22,280**	**22,271**	**22,323**	**22,301**	**22,385**	**22,469**	**22,534**	**23,615**	**23,605**	**23,602**	**23,601**	**24,342**	**24,339**	**24,097**	**25,200**
Demand Side Management (DSM)																
16	**Cumulative DSM Capacity**	**426**	**433**	**442**	**450**	**459**	**455**	**455**	**455**	**455**	**455**	**455**	**455**	**455**	**455**	**455**
17	**Cumulative Capacity w/ DSM**	**22,706**	**22,704**	**22,764**	**22,751**	**22,843**	**22,925**	**22,990**	**24,070**	**24,061**	**24,057**	**24,056**	**24,798**	**24,794**	**24,552**	**25,655**
Reserves w/ DSM																
18	Generating Reserves	3,972	3,942	3,825	3,696	3,661	3,549	3,377	4,310	4,095	3,911	3,707	4,278	4,104	3,693	4,582
19	**% Reserve Margin**	**21%**	**21%**	**20%**	**19%**	**19%**	**18%**	**17%**	**22%**	**21%**	**19%**	**18%**	**21%**	**20%**	**18%**	**22%**

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Table 7-B Load, Capacity and Reserves Table – Summer

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2017 Annual Plan

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Load Forecast															
1 Duke System Peak	19,000	18,955	19,156	19,267	19,368	19,531	19,690	19,860	20,060	20,250	20,416	20,561	20,685	20,834	20,970
2 Firm Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(168)	(253)	(333)	(413)	(491)	(570)	(643)	(714)	(782)	(869)	(959)	(1,030)	(1,084)	(1,133)	(1,172)
4 Adjusted Duke System Peak	**18,833**	**18,702**	**18,823**	**18,854**	**18,877**	**18,961**	**19,047**	**19,147**	**19,277**	**19,381**	**19,457**	**19,530**	**19,601**	**19,701**	**19,797**
Existing and Designated Resources															
5 Generating Capacity	20,216	20,869	20,879	20,932	20,978	21,024	21,071	21,071	20,854	20,854	20,854	20,854	20,338	20,338	20,178
6 Designated Additions / Uprates	653	10	52	46	46	46	0	365	0	0	0	0	0	0	0
7 Retirements / Derates	0	0	0	0	0	0	0	(582)	0	0	0	(516)	0	(160)	0
8 Cumulative Generating Capacity	**20,869**	**20,879**	**20,932**	**20,978**	**21,024**	**21,071**	**21,071**	**20,854**	**20,854**	**20,854**	**20,854**	**20,338**	**20,338**	**20,178**	**20,178**
Purchase Contracts															
9 Cumulative Purchase Contracts	**388**	**372**	**392**	**351**	**390**	**407**	**406**	**404**	**397**	**396**	**392**	**377**	**376**	**314**	**305**
Non-Compliance Renewable Purchases	173	188	210	256	301	321	320	318	312	310	309	308	306	306	305
Non-Renewables Purchases	215	184	182	95	88	86	86	85	85	85	83	70	70	8	0
Undesignated Future Resources															
10 Nuclear															1,117
11 Combined Cycle								1,151				1,151			
12 Combustion Turbine															
13 Solar															
Renewables															
13 **Cumulative Renewables Capacity**	359	490	522	651	761	944	1,132	1,166	1,156	1,148	1,145	1,139	1,131	1,124	1,119
14 **Combined Heat & Power**	0	0	40	0	40	0	0	0	0	0	0	0	0	0	0
15 Cumulative Production Capacity	**21,616**	**21,741**	**21,885**	**22,020**	**22,255**	**22,502**	**22,689**	**23,654**	**23,638**	**23,628**	**23,622**	**24,236**	**24,227**	**23,998**	**25,101**
Demand Side Management (DSM)															
16 Cumulative DSM Capacity	**1,023**	**1,047**	**1,073**	**1,097**	**1,106**	**1,104**	**1,104**	**1,104**	**1,104**	**1,104**	**1,104**	**1,104**	**1,104**	**1,104**	**1,104**
17 Cumulative Capacity w/ DSM	**22,640**	**22,788**	**22,958**	**23,117**	**23,361**	**23,606**	**23,793**	**24,758**	**24,742**	**24,732**	**24,725**	**25,340**	**25,330**	**25,102**	**26,205**
Reserves w/ DSM															
18 Generating Reserves	3,807	4,086	4,135	4,264	4,484	4,645	4,746	5,612	5,465	5,352	5,268	5,810	5,730	5,401	6,407
19 % Reserve Margin	**20%**	**22%**	**22%**	**23%**	**24%**	**24%**	**25%**	**29%**	**28%**	**28%**	**27%**	**30%**	**29%**	**27%**	**32%**

DEC - 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 tables. All values are MW (winter ratings) except where shown as a Percent.

1. Planning is done for the peak demand for the Duke Energy Carolinas System including Nantahala.

   A firm wholesale backstand agreement for 47 MW between Duke Energy Carolinas and PMPA starts on 1/1/2014 and continues through the end of 2020. This backstand is included in Line 1.

2. No additional firm sales are included.

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, 2017.

   Includes 101 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for North Carolina Municipal Power Agency #1 (NCMPA1) firm capacity sale.

6. Capacity Additions include:

   Runner upgrades on each of the four Bad Creek pumped storage units. Each upgrade is expected to be 46.4 MW and are projected to be available in the winter of 2021 – 2024. One unit will be upgraded per year.

   Lee Combined Cycle is reflected in 2018 (683 MW). This is the DEC capacity net of 100 MW to be owned by NCEMC.

   Lincoln County CT project is reflected in the winter of 2025 (402 MW). The CPCN application for this project was filed on June 12, 2017.

   Duke Energy Carolinas hydro units scheduled to be repaired and returned to service. The units are returned to service in the 2017-2020 timeframe and total 16 MW.

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

7. A planning assumption for coal retirements has been included in the 2017 IRP.

   Allen Steam Station Units 1-3 (604 MW) are assumed to retire in December 2024.

   Allen Steam Station Units 4-5 (526 MW) are assumed to retire in December 2028.

   Nuclear Stations are assumed to retire at the end of their current license extension.

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

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

   All retirement dates are subject to review on an ongoing basis. Dates used in the 2017 IRP are for planning purposes only.

8. Sum of lines 5 through 7.

9. Cumulative Purchase Contracts including purchased capacity from PURPA Qualifying Facilities.

   Additional line items are shown under the total line item to show the amounts of renewable and traditional QF purchases.

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

10. Addition of 1,117 MW new nuclear unit additions assumed in December 3031 and December 3033.

    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.

11. New combined cycle resources economically selected to meet load and minimum planning reserve margin.

    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.

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

Addition of 1,282 MW of combined cycle capacity online December 2024 and December 2028.

12. New combustion turbine resources economically selected to meet load and minimum planning reserve margin.

    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.

    No combustion turbine capacity was selected in the Base Case.

13. Resources to comply with NC REPS, HB 589 along with solar customer product offerings such as Green Source and the SC DER Program were input as existing resources.

14. Two 21.7 MW (winter) combined heat and power units included in both December 2019 and December 2021.

15. Sum of lines 8 through 14.

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

17. Sum of lines 15 and 16.

18. The difference between lines 17 and 4.

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

    Line 18 divided by Line 4.

    Minimum winter target planning reserve margin is 17%.

Technologies Considered

Similar to the 2016 IRP, the Company considered a diverse range of technology choices utilizing a variety of different fuels in order to meet future generation needs in the 2017 IRP. The Company conducted an economic screening analysis of various technologies as part of the 2017 IRP, with changes from the 2016 IRP highlighted below.

Dispatchable (Winter Ratings)

- Base load – 782 MW Ultra-Supercritical Pulverized Coal with CCS
- Base load – 557 MW 2x1 Integrated Gasification Combined Cycle (IGCC) with Carbon Capture Sequestration (CCS)
- Base load – 2 x 1,117 MW Nuclear Units (AP1000)
- Base load – **638 MW** – 1x1x1 Advanced Combined Cycle (**No Inlet Chiller** and Fired)
- Base load – **1,281 MW** – 2x2x1 Advanced Combined Cycle (**No Inlet Chiller** and Fired)
- Base load – 21.7 MW – Combined Heat & Power
- Peaking/Intermediate – **195 MW** 4 x LM6000 Combustion Turbines (CTs)
- Peaking/Intermediate – 200 MW, 12 x Reciprocating Engine Plant
- Peaking/Intermediate – **549 MW 2 x G/H-Class Combustion Turbines (CTs)**
- Peaking/Intermediate – **740 MW 2 x J-Class Combustion Turbines (CTs)**
- Peaking/Intermediate – **942 MW** 4 x 7FA.05 Combustion Turbines (CTs)
- Renewable – **5 MW / 2.5 MWh** Li-ion Battery
- Renewable – **5 MW / 20 MWh** Li-ion Battery
- Renewable – **2 MW Solar Photovoltaic (PV) plus 2 MW / 8 MWh** Li-ion Battery

Non-Dispatchable (Nameplate)

- Renewable – 5 MW Landfill Gas
- Renewable – 150 MW Wind - On-Shore
- Renewable – 5 MW Solar PV, Fixed-tilt (FT)
- Renewable – **50 MW Solar PV, Fixed-tilt (FT)**
- Renewable – **50 MW Solar PV, Single Axis Tracking**
- Renewable – **1300 MW Pumped Storage - Brownfield**
- Renewable – 5 MW Landfill Gas

Combined Cycle base capacities and technologies: Based on proprietary third party engineering studies, the 2x2x1 Advanced CC saw an increase in base load of 62 MW. The older version base 2x1 CC and the 3x1 Advanced CC were not considered in the updated IRP. However, as the Company begins the process of evaluating particular technologies for future undesignated generation needs, these technologies, along with other new technologies, may be considered based on factors such as generation requirements, plot size, new environmental regulations, etc.

Combustion Turbine base capacities and technologies: Based on proprietary third party engineering studies, the F-Frame CT technology saw a slight increase in winter capacity. The LM6000 CTs were not considered in the updated IRP. However, as the Company begins the process of evaluating particular technologies for future undesignated generation needs, these technologies, along with other new technologies, may be considered based on factors such as generation requirements, plot size, new environmental regulations, etc.

CHP: As mentioned previously, two 43-MW (winter) blocks of Combined Heat and Power are considered in the 2017 IRP and are included as resources for meeting future generation needs. DEC has signed agreements and obtained regulatory approval for a 15 MW CHP at Clemson University, which is expected to be in service by 2020. Filing for a CPCN for a 21 MW CHP at Duke University has been delayed pending the resolution of issues raised by the University. Discussions with other potential steam hosts are currently underway. As CHP continues to be implemented, future IRP processes will incorporate additional CHP as appropriate.

Energy Storage: Energy storage solutions, in particular batteries, are becoming an increasing necessity for support of grid services, including frequency regulation, solar smoothing, and/or energy shifting from localized renewable energy sources with a high incidence of intermittency (i.e. solar and wind). These technologies are capable of providing resiliency benefits and economic value for the utility and its customers. Duke Energy owns and operates several battery projects that have been in operation since 2011 through its Emerging Technology Office, mainly in support of regulating grid frequency and voltage, integrating renewables and energy time shifting.

Duke Energy is committed to supporting emerging technologies that can complement more conventional technologies and is in a prime position to optimize the investment in batteries by dispatching them in a manner that directly benefits customers. The Company intends to begin investing in multiple systems dispersed throughout its South and North Carolina service territory that will be located on property owned by the Company or leased from its customers. These deployments will allow Duke Energy and its customers to evaluate the costs and impacts of batteries deployed at a significant scale, explore the nature of new offerings desired by customers, and fill knowledge gaps.

Duke Energy Progress currently has one battery constructed and two in the interconnection queue in the western Carolinas region.

Pumped Storage Hydropower (PSH), another form of Energy Storage is the only conventional, mature, commercial, utility-scale bulk 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 Carolinas currently has two PSH assets, Bad Creek Reservoir and Jocassee Hydro with an approximate combined generating capacity of 2,140 MW.

Expansion Plan and Resource Mix

A tabular presentation of the 2017 Base Case resource plan represented in the above Load, Capacity and Reserves (LCR) table is shown below:

Table 7-C DEC Base Case Resources – Winter (with CO_2)

Duke Energy Carolinas Resource Plan [1] Base Case - Winter				
Year	**Resource**		**MW**	
2018	Lee CC		683	
2019	Hydro Refurb Return to Service		10	
2020	Hydro Refurb Return to Service	CHP	6	43
2021	Bad Creek Uprate		46.4	
2022	Bad Creek Uprate	CHP	46.4	43
2023	Bad Creek Uprate		46.4	
2024	Bad Creek Uprate		46.4	
2025	Lincoln CT	New CC	402	1282
2026				
2027				
2028				
2029	New CC		1282	
2030				
2031				
2032	Lee Nuclear		1117	

Notes: (1) Table includes both designated and undesignated capacity additions
Future additions of renewables, EE and DSM not included
(2) Lee CC capacity is net of NCEMC ownership of 100 MW
(3) Rocky Creek Units currently offline for refurbishment; these are expected return to service dates
(4) Lee Nuclear in service dates are assumed to be Dec, 2031 and Dec, 2033.
(5) An application was filed for a CPCN for the Lincoln County CT Addition Project on June 12, 2017.
The Lincoln CT is now included as a designated resource in the 2017 IRP.

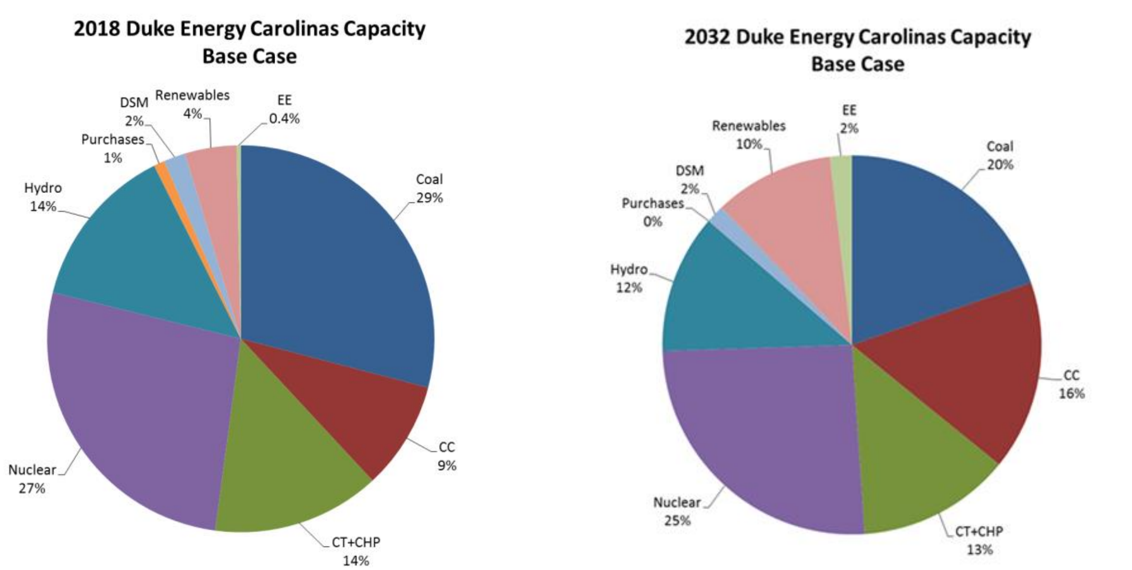
Table 7-D DEC Base Case Resources (with CO_2) Cumulative Winter Totals

DEC Base Case Resources
Cumulative Winter Totals - 2018 - 2032

Nuclear	1117
CC	3247
CT	402
Hydro	202
CHP	86
Total	5054

The following charts illustrate both the current and forecasted capacity by fuel type for the DEC system, as projected in the Base Case. As demonstrated in Chart 7-A, the capacity mix for the DEC system changes with the passage of time. In 2032, the Base Case projects that DEC will have a smaller percentage reliance on coal, a continued reliance on nuclear and gas-fired CTs, and a higher reliance on gas-fired combined cycles, renewable resources and EE as compared to the current state.

Chart 7-A 2018 and 2032 Base Case Winter Capacity Mix



As discussed earlier, the Company developed three additional cases which represent variations of the Base Case. The expansion plans for these cases are shown below in Table 6-E.

A description of these additional cases are:

- "No Carbon Case" - No carbon legislation and without nuclear relicensing.
- "Carbon and Nuclear Relicensing Case" – Carbon legislation in 2026 and with nuclear relicensing.
- "No Carbon with Nuclear Relicensing Case" – No carbon legislation and with nuclear relicensing.

A representation of the expansion plans for these cases is shown in Table 7-E.

Table 7-E Additional Cases - Winter

Duke Energy Carolinas Resource Plans Additional Cases - Winter (Resource - MW)			
Year	**No Carbon Case w/o Relicensing Case**	**Carbon w/ Relicensing Case**	**No Carbon w/ Relicensing Case**
2018	Lee CC - 683	Lee CC - 683	Lee CC - 683
2019	Hydro Refurb - 10	Hydro Refurb - 10	Hydro Refurb - 10
2020	Hydro Refurb - 6 CHP - 43	Hydro Refurb - 6 CHP - 43	Hydro Refurb - 6 CHP - 43
2021	Bad Creek - 47.4	Bad Creek - 47.4	Bad Creek - 47.4
2022	Bad Creek - 47.4 CHP - 43	Bad Creek - 47.4 CHP - 43	Bad Creek - 47.4 CHP - 43
2023	Bad Creek - 47.4	Bad Creek - 47.4	Bad Creek - 47.4
2024	Bad Creek - 47.4	Bad Creek - 47.4	Bad Creek - 47.4
2025	Lincoln CT - 402 New CC - 1282	Lincoln CT - 402 New CC - 1282	Lincoln CT - 402 New CC - 1282
2026			
2027			
2028			
2029	New CT - 942	New CC - 1282	New CT - 942
2030			
2031	New CT - 471		New CT - 471
2032	New CT - 471	New CT - 471	

8. SHORT-TERM ACTION PLAN:

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

Continued Reliance on EE and DSM Resources

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

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

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

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

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

Continued Focus on Renewable Energy Resources

- DEC is committed to full compliance with the SC DER Program in South Carolina and NC REPS in North Carolina. Due to NC's current favorable avoided cost rate and 15 year contract terms for QFs under PURPA the Company has experienced a substantial increase in solar QFs in the interconnection queue. With this significant level of interest in solar development, DEC continues to procure renewable purchase power resources, when economically viable, as part of its Compliance Plans. DEC is also pursuing the addition of new utility-owned solar on the DEC system.

- DEC is committed to complying with the newly signed HB 589 legislation. The Company has made assumptions to account for the non-compliance PURPA renewable purchases part of the "Transition" MW of HB 589, as well as the competitive procurement, renewable energy procurement for large customers, and community solar components of the bill.

- DEC continues to evaluate market options for renewable generation and procure capacity, as appropriate. Purchase Power Agreements (PPAs) have been signed with developers of solar PV and landfill gas resources. Additionally, REC purchase agreements have been executed for purchases of unbundled RECs from wind, solar PV, solar thermal and hydroelectric facilities.

- DEC has signed agreements and obtained regulatory approval for a 15 MW CHP at Clemson University, which is expected to be in service by 2020. Filing for a CPCN for a 21 MW CHP at Duke University has been delayed pending the resolution of issues raised by the University. Discussions with other potential steam hosts are currently underway. DEC continues to pursue CHP opportunities, as appropriate, and placeholders have been included in the IRP.

Cancellation of the Lee Project and Continue to Evaluate Nuclear

In its last filed IRP on September 1, 2016, DEC indicated it continued to have a long-term need for new nuclear generation. The Base Case scenario, which included a cost on carbon emissions, assumed new nuclear resources to meet load and minimum planning reserve margin with Lee Nuclear additions in 2026 and 2028 (2,234 MW).

On December 19, 2016, the Company received the COL for the Lee Nuclear Project from the U.S. Nuclear Regulatory Commission. On August 25, 2017, DEC filed a request to cancel the Lee Nuclear Project as that project was originally envisioned and included in prior IRPs. On August 25th, DEC filed notice of its request with the Public Service Commission of South Carolina in Docket 2011-20-E. Also, the cancellation request is now pending before the NCUC in Docket Nos. E-7, Sub 819 and E-7 Sub 1146. DEC's decision to cancel the project resulted from events that have occurred subsequent to receipt of the Lee Nuclear COL. These events include the AP-1000 technology owner, designer and engineer, Westinghouse, and its parent company, Toshiba Corporation, indicating that they intend to exit the nuclear construction business in the U.S., including the Lee Project; the subsequent bankruptcy of Westinghouse, and the substantial cost increases and schedule delays associated with the Vogtle and V.C. Summer new nuclear construction projects; the latter of which SCE&G and project joint owner, Santee Cooper, recently canceled.

In addition to these developments, revised projections indicate that new nuclear baseload capacity is needed only under a carbon-constrained scenario with the assumption of no existing nuclear re-licensing. Even in that scenario, the added capacity would not be needed until much later in the 15-year planning horizon (2031, 2033) than projected in the 2016 IRP.

The Company views all of its existing nuclear fleet as excellent candidates for license extensions, however to date, no existing nuclear plant operating licenses have been extended from 60 years to 80 years in the United States. As such, there is uncertainty regarding license extension, and any costs associated with continuing to operate for an additional 20 years. A discussion of the Company's activities is included below.

Subsequent License Renewal for Nuclear Power Plants

Duke Energy is considering Oconee Nuclear Station for its first nuclear site to submit an SLR application and extend the licenses to 80 years. The remaining nuclear fleet sites will follow where the cost/benefit proves acceptable.

An Advance was approved on May 12, 2016 for the development portion of the ONS SLR project. These funds are being used to further develop and refine the Project Plan including scope, schedule, cost, risk, and other project elements. The next phase of funding for the project is expected to be submitted for approval in 2Q2018. At this time a final decision to extend the ONS or any other Duke Energy nuclear power plants' operating licenses to 80 years has not been made.

Addition of Clean Natural Gas Resources

- Construction on the Lee combined cycle plant (Lee CC) at the Lee Steam Station site located in Anderson, SC is being completed. The unit is expected to be online in late 2017 and available to meet the 2018 winter peak.

- A CPCN application was filed on June 12, 2017 for the construction of a new, state-of-the-art 402 MW combustion turbine at the existing Lincoln County CT site. While Duke Energy is not expected to take care, custody, and control of the CT until October 2024, DEC and its customers will benefit from the energy produced by the generating unit beginning in 3Q2020 as the unit begins an extended commissioning and testing period.

- Complete engineering phase of Cliffside Dual Fuel Optimization (DFO) project by year-end 2017, and begin construction 1Q2018. Current commercial operation date (COD) for both Units 5 & 6 is year-end 2018. The Cliffside DFO Project enables up to 100% gas co-firing on Unit 6 and up to 10% gas co-firing on Unit 5 when the units are running simultaneously. The project is designed to maximize the value of CS5 and CS6, improve unit dispatch, and increase unit flexibility by lowering the delivered fuel cost to the complex through gas co-firing.

- As part of the Company's effort to modernize and increase unit flexibility, and in order to take advantage of continued historically low natural gas prices, DEC is moving forward with a modification to Belews Creek Coal Units 1 and 2. The project will enable 50% natural gas co-firing on each unit. Similar to the Cliffside DFO Project, co-firing at Belews Creek is designed to maximize the value of these units, improve unit dispatch, and increase unit flexibility by lowering the delivered fuel cost to the complex through gas co-firing. Based on the current schedule, COD for Unit 1 is December 2019 and Unit 2 is December 2020.

Expiration of Wholesale Sales Contracts (PUBLIC)

In the 2018-2022 timeframe, DEC has several wholesale sales contracts that are scheduled to expire. At this time, DEC is not relying on contract extensions for these contracts. As such, these contract expirations are included in the IRP and Short-Term Action Plan. A summary of those expirations is shown in Table 8-A below. In addition to the expirations shown in this five year period, additional contracts expire during the 15-year IRP study period.

Table 8-A Wholesale Sales Contract Expirations
(BEGIN CONFIDENTIAL)

[redacted]

(END CONFIDENTIAL)

Table 8-A Wholesale Sales Contract Expirations

DEC	
	Wholesale Sales Contract Expirations
2018	-
2019	(Concord) (Kings Mountain) (Greenwood) **302 MW**
2020	-
2021	-
2022	-
Total	**302 MW**

Expiration of Wholesale Purchase Contracts

In the 2018-2022 timeframe, DEC has several wholesale purchases that are scheduled to expire. At this time, DEC is not relying on contract extensions on these contracts. As such, these contract expirations are included in the IRP and Short-Term Action Plan. A summary of those expirations is shown in Table 8-B below. In addition to the expirations shown in this five year period, additional contracts expire during the 15-year IRP study period.

Table 8-B Wholesale Purchase Contract Expirations
(BEGIN CONFIDENTIAL)

[redacted]

(END CONFIDENTIAL)

Continued Focus on System Reliability and Resource Adequacy for DEC System

The 2016 and 2017 DEC and DEP IRPs incorporated a 17% winter reserve margin target based on results of the resource adequacy studies completed in 2016. The NCUC's 2016 IRP Order concluded that the reserve margins included in the DEC and DEP IRPs are reasonable for planning purposes. However, the Commission noted concerns outlined by the Public Staff and a report submitted by SACE, NRDC, and Sierra Club consultant Wilson. DEC and DEP responded to these concerns in the Companies' detailed 2016 IRP Reply Comments regarding reserve margins and winter capacity planning. In addition, since the issuance of the 2016 IRP Order, the Companies

Table 8-B Wholesale Purchase Contract Expirations

	DEC
	Wholesale Purchase Contract Expirations
2018	**-**
2019	**38 MW**
2020	**3 MW**
2021	**86 MW**
2022	**6 MW**
Total	**133 MW**

have met with and initiated further discussions with the Public Staff to identify and address any remaining issues. The Companies and the Public Staff plan to file a joint report summarizing the on-going review and conclusions within 150 days of the filing of the Companies' 2017 IRP updates as directed by the NCUC.

Continued Focus on Evolving Regulations, Environmental Compliance and Wholesale Activities

- Retired older coal generation. As of April 2015, Duke Energy Carolinas has no remaining older, un-scrubbed coal units in operation. The Company has retired approximately 1,700 MW of un-scrubbed, older coal units and over 400 MW of older combustion turbines.

- The 2017 IRP shows an additional approximately 1,300 MW of retirements over the study period with just over 1,100 MW of coal being retired at the Allen site and just over 170 MW of combustion turbine capacity at Lee 3.

- Continue to monitor the status of EPA's Clean Power Plan. In response to a March 28, 2017 Executive Order, EPA has undertaken a review of the rule to determine whether it should be suspended, revised, or rescinded. The rule remains in effect pending the outcome of litigation and EPA's review of the rule. EPA has not announced a schedule for completing its review.

- Continue to investigate the future environmental control requirements and resulting operational impacts associated with existing and potential environmental regulations such as the Mercury Air Toxics Standard (MATS), the Coal Combustion Residuals rule, the Cross-State Air Pollution Rule (CSAPR), and the new ozone National Ambient Air Quality Standard (NAAQS).

- Aggressively pursue compliance in South Carolina and North Carolina in addressing coal ash management and ash pond remediation. Ensure timely compliance plans and their associated costs are contemplated within the planning process and future integrated resource plans, as appropriate.

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

- Continue to monitor energy-related statutory and regulatory activities.

- Continue to examine the benefits of joint capacity planning and pursue appropriate regulatory actions.

A summarization of the capacity resources for the Base Case in the 2017 IRP is shown in Table 8-C below. Capacity retirements and additions are presented as incremental values in the year in which the change is projected to impact the winter peak. The values shown for renewable resources, EE and DSM represent cumulative totals.

Table 8-C DEC Short-Term Action Plan

Duke Energy Carolinas Short-Term Action Plan (1) (6)

			Compliance Renewable Resources (Cumulative Nameplate MW)			
Year	Retirements	Additions	Solar (2)	Biomass/Hydro	EE	DSM (3)
2018		683 MW Lee CC (4)	889	121	83	426
2019		10 MW Hydro Refurb (5)	1214	116	104	433
2020		6 MW Hydro Refurb (5) 43 MW CHP	1333	115	141	442
2021		46 MW Bad Creek	1711	115	175	450
2022		46 MW Bad Creek 43 MW CHP	2088	96	227	459

Notes:

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

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

(3) Includes impacts of grid modernization.

(4) 683 MW is net of NCEMC portion of Lee CC.

(5) Rocky Creek is currently offline for refurbishment. Hydro Refurb MW in table represent expected return to service date.

(6) First resource need moved from 2023 in the 2016 IRP to 2025 in the 2017 IRP.

9. CONCLUSIONS:

DEC continues to focus on the needs of customers by meeting the growing demand in the most economical and reliable manner possible. The Company continues to improve the IRP process by determining best practices and making changes to more accurately and realistically represent the DEC System in its planning practices. The 2017 IRP represents a 15 year projection of the Company's plan to balance future customer demand and supply resources to meet this demand plus a 17% minimum winter planning reserve margin. Over the 15-year planning horizon, DEC expects to require 5,054 MW of additional generating resources in addition to the incremental renewable resources, EE and DSM already in the resource plan.

The Company focuses on the needs of the short-term, while keeping a close watch on market trends and technology advancements to meet the demands of customers in the long-term. The Company's short-term and long-term plans are summarized below:

Short-Term

Over the next 5 years, DEC's 2017 IRP focuses on the following:

- Complete construction of the Lee CC plant in Anderson, SC scheduled for operation in November 2017.
- Begin work on the upgrades to the Bad Creek units.
- Continue work with Astrapé and the Public Staff to resolve outstanding issues regarding the 2016 Resource Adequacy Study.
- Pursue investment in a limited number of battery storage projects to gain additional operational and technical experience with evolving utility-scale storage technologies.
- Procure CHP resources as cost-effective and diverse generation sources, as appropriate.
- Pending the CPCN application outcome, pursue new Lincoln CT to begin providing low-cost energy benefits to DECs customers in 3Q2020, prior to taking care, custody, and control of the CT in 4Q2024.
- Continue work on the Cliffside and Belews Creek dual fuel optimization projects to increase flexibility of the DEC system.
- Continue to review energy storage options for feasibility on the DEC system.
- Continue to meet the SC DER Program and NC REPS compliance plans, as well as the new HB 589 bill, and invest in additional cost-effective and diverse renewable resources.

- Begin compliance with HB 589, by completing the "Transition" MW, and connecting a portion of the competitive procurement, renewable energy procurement for large customers, and community solar components of the bill.
- Continue to grow and enhance EE and DSM in the Carolinas region.
- Continue to seek additional DSM programs that will specifically benefit during winter peak situations.
- Continue work on the 15 MW CHP at Clemson University, which is expected to be in service by 2020. Complete the filing for a CPCN for a 21 MW CHP at Duke University pending the resolution of issues raised by the University.

Long-Term

Beyond the next 5 years, DEC's 2017 IRP focuses on the following:

- Continue plan to pursue new Lincoln CT, expected to be available for the winter peak of 2025.
- Continue discussions with other potential steam hosts to pursue CHP opportunities, as appropriate.
- Continue to meet and NC REPS compliance plans, as well as the new HB 589 bill, and invest in additional cost-effective and diverse renewable resources.
- Continue completing all portions of the HB 589 bill.
- Continue to grow and enhance EE and DSM in the Carolinas region.
- Continue to seek additional DSM programs that will specifically benefit during winter peak situations.

DEC's goal is to continue to diversify the DEC system by adding a variety of cost-effective, reliable, clean resources to meet customer demand. Over the next 15 years, the Company projects filling the increasing demand with investments in natural gas, nuclear, renewables, EE and DSM.

10. DUKE ENERGY CAROLINAS OWNED GENERATION:

Duke Energy Carolinas' generation portfolio includes a balanced mix of resources with different operating and fuel characteristics. This mix is designed to provide energy at the lowest reasonable cost to meet the Company's obligation to serve its customers. Duke Energy Carolinas-owned generation, as well as purchased power, is evaluated on a real-time basis in order to select and dispatch the lowest-cost resources to meet system load requirements. In 2016, Duke Energy Carolinas' nuclear, coal-fired and gas-fired generating units met the vast majority of customer needs by providing 61%, 26% and 12%, respectively, of Duke Energy Carolinas' energy from generation. Hydroelectric generation, solar generation, long term PPAs, and economical purchases from the wholesale market supplied the remainder.

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

Existing Generating Units and Ratings [a, b, c, d]
All Generating Unit Ratings are as of July 1, 2017

Coal						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Allen	1	167	162	Belmont, N.C.	Coal	Peaking
Allen	2	167	162	Belmont, N.C.	Coal	Peaking
Allen	3	270	258	Belmont, N.C.	Coal	Peaking
Allen	4	267	257	Belmont, N.C.	Coal	Intermediate
Allen	5	259	259	Belmont, N.C.	Coal	Peaking
Belews Creek	1	1,110	1,110	Belews Creek, N.C.	Coal	Base
Belews Creek	2	1,110	1,110	Belews Creek, N.C.	Coal	Base
Cliffside	5	546	544	Cliffside, N.C.	Coal	Peaking
Cliffside	6	844	844	Cliffside, N.C.	Coal	Intermediate
Marshall	1	380	370	Terrell, N.C.	Coal	Intermediate
Marshall	2	380	370	Terrell, N.C.	Coal	Intermediate
Marshall	3	658	658	Terrell, N.C.	Coal	Base
Marshall	4	660	660	Terrell, N.C.	Coal	Base
Total Coal		6,818	6,764			

Combustion Turbines						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Lee	7C	48	42	Pelzer, S.C.	Natural Gas/Oil-Fired	Peaking
Lee	8C	48	42	Pelzer, S.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	1	98	76	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	2	99	76	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	3	99	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	4	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	5	97	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	6	97	73	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	7	98	76	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	8	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	9	97	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	10	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	11	98	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	12	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	13	98	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	14	97	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	15	98	73	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Lincoln	16	97	73	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	1	92	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	2	92	70	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	3	92	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	4	92	70	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	5	90	69	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	6	92	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	7	92	70	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Mill Creek	8	93	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	1	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	2	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	3	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	4	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Rockingham	5	179	165	Rockingham, N.C.	Natural Gas/Oil-Fired	Peaking
Total NC		2,460	2,018			
Total SC		831	647			
Total CTs		3,291	2,665			

Natural Gas Fired Boiler						
		Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Lee	3	173	170	Pelzer, N.C.	Nat. Gas	Peaking
Total Nat. Gas		173	170			

Combined Cycle						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Buck	CT11	206	178	Salisbury, N.C.	Natural Gas	Base
Buck	CT12	206	178	Salisbury, N.C.	Natural Gas	Base
Buck	ST10	304	312	Salisbury, N.C.	Natural Gas	Base
Buck CTCC		716	668			
Dan River	CT8	199	171	Eden, N.C.	Natural Gas	Base
Dan River	CT9	199	171	Eden, N.C.	Natural Gas	Base
Dan River	ST7	320	320	Eden, N.C.	Natural Gas	Base
Dan River CTCC		718	662			
Total CTCC		1,434	1,330			

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

Hydro						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
99 Islands	1	2.4	2.4	Blacksburg, S.C.	Hydro	Peaking
99 Islands	2	2.4	2.4	Blacksburg, S.C.	Hydro	Peaking
99 Islands	3	2.4	2.4	Blacksburg, S.C.	Hydro	Peaking
99 Islands	4	2.4	2.4	Blacksburg, S.C.	Hydro	Peaking
99 Islands	5	0	0	Blacksburg, S.C.	Hydro	Peaking
99 Islands	6	0	0	Blacksburg, S.C.	Hydro	Peaking
Bear Creek	1	9.5	9.5	Tuckasegee, N.C.	Hydro	Peaking
Bridgewater	1	15	15	Morganton, N.C.	Hydro	Peaking
Bridgewater	2	15	15	Morganton, N.C.	Hydro	Peaking
Bridgewater	3	1.5	1.5	Morganton, N.C.	Hydro	Peaking
Bryson City	1	0.4	0.4	Whittier, N.C.	Hydro	Peaking
Bryson City	2	0.5	0.5	Whittier, N.C.	Hydro	Peaking
Cedar Cliff	1	6.4	6.4	Tuckasegee, N.C.	Hydro	Peaking
Cedar Cliff	2	0.4	0.4	Tuckasegee, N.C.	Hydro	Peaking
Cedar Creek	1	15	15	Great Falls, S.C.	Hydro	Peaking
Cedar Creek	2	15	15	Great Falls, S.C.	Hydro	Peaking
Cedar Creek	3	15	15	Great Falls, S.C.	Hydro	Peaking
Cowans Ford	1	81	81	Stanley, N.C.	Hydro	Peaking
Cowans Ford	2	81	81	Stanley, N.C.	Hydro	Peaking
Cowans Ford	3	81	81	Stanley, N.C.	Hydro	Peaking
Cowans Ford	4	81	81	Stanley, N.C.	Hydro	Peaking
Dearborn	1	14	14	Great Falls, S.C.	Hydro	Peaking
Dearborn	2	14	14	Great Falls, S.C.	Hydro	Peaking
Dearborn	3	14	14	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	1	11	11	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	2	10	10	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	3	10	10	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	4	11	11	Great Falls, S.C.	Hydro	Peaking
Fishing Creek	5	8	8	Great Falls, S.C.	Hydro	Peaking
Franklin	1	0.5	0.5	Franklin, N.C.	Hydro	Peaking
Franklin	2	0.5	0.5	Franklin, N.C.	Hydro	Peaking
Gaston Shoals	3	0	0	Blacksburg, S.C.	Hydro	Peaking
Gaston Shoals	4	2	2	Blacksburg, S.C.	Hydro	Peaking
Gaston Shoals	5	2	2	Blacksburg, S.C.	Hydro	Peaking
Gaston Shoals	6	2	2	Blacksburg, S.C.	Hydro	Peaking

Hydro (cont.)						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Great Falls	1	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	2	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	3	0	0	Great Falls, S.C.	Hydro	Peaking
Great Falls	4	0	0	Great Falls, S.C.	Hydro	Peaking
Great Falls	5	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	6	3	3	Great Falls, S.C.	Hydro	Peaking
Great Falls	7	0	0	Great Falls, S.C.	Hydro	Peaking
Great Falls	8	0	0	Great Falls, S.C.	Hydro	Peaking
Keowee	1	76	76	Seneca, S.C.	Hydro	Peaking
Keowee	2	76	76	Seneca, S.C.	Hydro	Peaking
Lookout Shoals	1	9	9	Statesville, N.C.	Hydro	Peaking
Lookout Shoals	2	9	9	Statesville, N.C.	Hydro	Peaking
Lookout Shoals	3	9	9	Statesville, N.C.	Hydro	Peaking
Mission	1	0.6	0.6	Murphy, N.C.	Hydro	Peaking
Mission	2	0.6	0.6	Murphy, N.C.	Hydro	Peaking
Mission	3	0.6	0.6	Murphy, N.C.	Hydro	Peaking
Mountain Island	1	14	14	Mount Holly, N.C.	Hydro	Peaking
Mountain Island	2	14	14	Mount Holly, N.C.	Hydro	Peaking
Mountain Island	3	17	17	Mount Holly, N.C.	Hydro	Peaking
Mountain Island	4	17	17	Mount Holly, N.C.	Hydro	Peaking
Nantahala	1	50	50	Topton, N.C.	Hydro	Peaking
Oxford	1	20	20	Conover, N.C.	Hydro	Peaking
Oxford	2	20	20	Conover, N.C.	Hydro	Peaking
Queens Creek	1	1.4	1.4	Topton, N.C.	Hydro	Peaking
Rhodhiss	1	9.5	9.5	Rhodhiss, N.C.	Hydro	Peaking
Rhodhiss	2	11.5	11.5	Rhodhiss, N.C.	Hydro	Peaking
Rhodhiss	3	12.4	12.4	Rhodhiss, N.C.	Hydro	Peaking
Rocky Creek	1	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	2	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	3	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	4	0	0	Great Falls, S.C.	Hydro	Peaking

Hydro (cont.)						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Rocky Creek	5	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	6	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	7	0	0	Great Falls, S.C.	Hydro	Peaking
Rocky Creek	8	0	0	Great Falls, S.C.	Hydro	Peaking
Tuxedo	1	3.2	3.2	Flat Rock, N.C.	Hydro	Peaking
Tuxedo	2	3.2	3.2	Flat Rock, N.C.	Hydro	Peaking
Tennessee Creek	1	9.8	9.8	Tuckasegee, N.C.	Hydro	Peaking
Thorpe	1	19.7	19.7	Tuckasegee, N.C.	Hydro	Peaking
Tuckasegee	1	2.5	2.5	Tuckasegee, N.C.	Hydro	Peaking
Wateree	1	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	2	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	3	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	4	17	17	Ridgeway, S.C.	Hydro	Peaking
Wateree	5	17	17	Ridgeway, S.C.	Hydro	Peaking
Wylie	1	18	18	Fort Mill, S.C.	Hydro	Peaking
Wylie	2	18	18	Fort Mill, S.C.	Hydro	Peaking
Wylie	3	18	18	Fort Mill, S.C.	Hydro	Peaking
Wylie	4	18	18	Fort Mill, S.C.	Hydro	Peaking
Total NC		627.7	627.7			
Total SC		473.6	473.6			
Total Hydro		1,101.3	1,101.3			

Solar						
		Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
NC Solar		4.19	38.6	N.C.	Solar	Intermittent

Nuclear						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
McGuire	1	1,199.0	1,158.0	Huntersville, N.C.	Nuclear	Base
McGuire	2	1,187.2	1,157.6	Huntersville, N.C.	Nuclear	Base
Catawba	1	1,198.7	1,160.1	York, S.C.	Nuclear	Base
Catawba	2	1,179.8	1,150.1	York, S.C.	Nuclear	Base
Oconee	1	865	847	Seneca, S.C.	Nuclear	Base
Oconee	2	872	848	Seneca, S.C.	Nuclear	Base
Oconee	3	881	859	Seneca, S.C.	Nuclear	Base
Total NC		2,386.2	2,315.6			
Total SC		4,996.5	4,864.2			
Total Nuclear		7,382.7	7,179.8			

Total Generation Capability		
	Winter Capacity (MW)	Summer Capacity (MW)
TOTAL DEC SYSTEM - N.C.	13,903	13,264
TOTAL DEC SYSTEM – S.C.	8,441	8,125
TOTAL DEC SYSTEM	22,344	21,389

Note a: Unit information is provided by State, but resources are dispatched on a system-wide basis.

Note b: Summer and winter capability does not take into account reductions due to future environmental emission controls.

Note c: Catawba Units 1 and 2 capacity reflects 100% of the station's capability, and does not factor in the North Carolina Municipal Power Agency #1's (NCMPA#1) decision to sell or utilize its 832 MW retained ownership in Catawba.

Note d: The Catawba units' multiple owners and their effective ownership percentages are:

Catawba Owner	Percent Of Ownership
Duke Energy Carolinas	19.246%
North Carolina Electric Membership Corporation (NCEMC)	30.754%
NCMPA#1	37.5%
PMPA	12.5%

Planned Uprates			
Unit	Date	Winter MW	Summer MW
None			

Planned Additions			
Unit	Date	Winter MW	Summer MW
Lee CC [a]	Nov 2017	783	753
Bad Creek 1	June 2023	46.4	46.4
Bad Creek 2	June 2020	46.4	46.4
Bad Creek 3	June 2021	46.4	46.4
Bad Creek 4	June 2022	46.4	46.4
Clemson CHP [b]	Nov 2019	15	15

Note a: Includes 100 MW ownership by NCEMC.
Note b: There is an additional placeholder for CHP projects in 2022.

Retirements				
Unit & Plant Name	Location	Capacity (MW) Winter / Summer	Fuel Type	Expected Retirement Date
Buck 3[a]	Salisbury, N.C.	76 / 75	Coal	05/15/11
Buck 4 [a]	Salisbury, N.C.	39 / 38	Coal	05/15/11
Cliffside 1 [a]	Cliffside, N.C.	39 / 38	Coal	10/1/11
Cliffside 2 [a]	Cliffside, N.C.	39 / 38	Coal	10/1/11
Cliffside 3 [a]	Cliffside, N.C.	62 / 61	Coal	10/1/11
Cliffside 4 [a]	Cliffside, N.C.	62 / 61	Coal	10/1/11
Dan River 1 [a]	Eden, N.C.	69 / 67	Coal	04/1/12
Dan River 2 [a]	Eden, N.C.	69 / 67	Coal	04/1/12
Dan River 3 [a]	Eden, N.C.	145 / 142	Coal	04/1/12
Buzzard Roost 6C [b]	Chappels, S.C.	22 /22	Combustion Turbine	10/1/12
Buzzard Roost 7C [b]	Chappels, S.C.	22 /22	Combustion Turbine	10/1/12
Buzzard Roost 8C	Chappels, S.C.	22 /22	Combustion Turbine	10/1/12
Buzzard Roost 9C [b]	Chappels, S.C.	22 /22	Combustion Turbine	10/1/12

Retirements (cont.)				
Unit & Plant Name	Location	Capacity (MW) Winter / Summer	Fuel Type	Expected Retirement Date
Buzzard Roost 10C [b]	Chappels, S.C.	18 / 18	Combustion Turbine	10/1/12
Buzzard Roost 11C [b]	Chappels, S.C.	18 / 18	Combustion Turbine	10/1/12
Buzzard Roost 12C [b]	Chappels, S.C.	18 / 18	Combustion Turbine	10/1/12
Buzzard Roost 13C [b]	Chappels, S.C.	18 / 18	Combustion Turbine	10/1/12
Buzzard Roost 14C [b]	Chappels, S.C.	18 / 18	Combustion Turbine	10/1/12
Buzzard Roost 15C [b]	Chappels, S.C.	18 / 18	Combustion Turbine	10/1/12
Riverbend 8C [b]	Mt. Holly, N.C.	0 / 0	Combustion Turbine	10/1/12
Riverbend 9C [b]	Mt. Holly, N.C.	30 / 22	Combustion Turbine	10/1/12
Riverbend 10C [b]	Mt. Holly, N.C.	30 / 22	Combustion Turbine	10/1/12
Riverbend 11C [b]	Mt. Holly, N.C.	30 / 20	Combustion Turbine	10/1/12
Buck 7C [b]	Spencer, N.C.	30 / 25	Combustion Turbine	10/1/12
Buck 8C [b]	Spencer, N.C.	30 / 25	Combustion Turbine	10/1/12
Buck 9C [b]	Spencer, N.C.	15 / 12	Combustion Turbine	10/1/12
Dan River 4C [b]	Eden, N.C.	0 / 0	Combustion Turbine	10/1/12
Dan River 5C [b]	Eden, N.C.	31 / 24	Combustion Turbine	10/1/12
Dan River 6C [b]	Eden, N.C.	31 / 24	Combustion Turbine	10/1/12
Riverbend 4 [a]	Mt. Holly, N.C.	96 / 94	Coal	04/1/13
Riverbend 5 [a]	Mt. Holly, N.C.	96 / 94	Coal	04/1/13
Riverbend 6 [c]	Mt. Holly, N.C.	136 / 133	Coal	04/1/13
Riverbend 7 [c]	Mt. Holly, N.C.	136 / 133	Coal	04/1/13
Buck 5 [c]	Spencer, N.C.	131 / 128	Coal	04/1/13
Buck 6 [c]	Spencer, N.C.	131 / 128	Coal	04/1/13
Lee 1 [d]	Pelzer, S.C.	100 / 100	Coal	11/6/14
Lee 2 [d]	Pelzer, S.C.	102 / 100	Coal	11/6/14
Lee 3 [e]	Pelzer, S.C.	170 / 170	Coal	05/12/15*
	Total	2121 / 2037 MW		

*converted to NG

Note a: Retirement assumptions associated with the conditions in the NCUC Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6.

Note b: The old fleet combustion turbines retirement dates were accelerated in 2009 based on derates, availability of replacement parts and the general condition of the remaining units.

Note c: The decision was made to retire Buck 5 & 6 and Riverbend 6 & 7 early on April 1, 2013. The original expected retirement date was April 15, 2015.

Note d: Lee Steam Units 1 and 2 were retired November 6, 2014.

Note e: The conversion of the Lee 3 coal unit to a natural gas unit was effective March 12, 2015.

Planning Assumptions – Unit Retirements

Unit & Plant Name	Location	Winter Capacity (MW)	Summer Capacity (MW)	Fuel Type	Expected Retirement
Allen 1[a]	Belmont, NC	167	162	Coal	12/2024
Allen 2[a]	Belmont, NC	167	162	Coal	12/2024
Allen 3[a]	Belmont, NC	270	258	Coal	12/2024
Allen 4[a]	Belmont, NC	267	257	Coal	12/2028
Allen 5[a]	Belmont, NC	259	259	Coal	12/2028
Lee 3	Pelzer, SC	173	170	NG	12/2030
Total		1,303	1,268		

Note a: Retirement assumptions are for planning purposes only; dates are based on useful life expectations of the unit.
Note b: Nuclear retirements for planning purposes are based on the end of current operating license.

11. NON-UTILITY GENERATION & WHOLESALE:

The following information describes the tables included in this chapter.

Wholesale Sales Contracts

This table includes wholesale sales contracts that are included in the 2017 Load Forecast. This information is **CONFIDENTIAL**.

Wholesale Purchase Contracts

This table includes all wholesale purchase contracts that are included as resources in the 2017 IRP. This information is **CONFIDENTIAL**.

Table 11-A Wholesale Sales Contracts

DEC Aggregated Wholesale Sales Contracts								
Commitment (MW)								
2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
1997	1797	2015	1782	1758	1777	1794	1807	1827

Customer	**Term**
Concord	2009-2018
Dallas	2009-2028
Due West	2009-2028
Forest City	2009-2028
Greenwood	2010-2018
Highlands	2010-2029
Kings Mountain	2009-2018
Lockhart	2009-2028
Prosperity	2009-2028
Western Carolina	2010-2021
Blue Ridge EMC	2010-2031
Central EPC	2013-2030
Haywood EMC	2009-2031
NCEMC	2009-2038
NCEMC	1985-2043
Piedmont EMC	2010-2031
PMPA	2014-2020
Rutherford EMC	

Notes:

- **For wholesale contracts, Duke Carolinas/Duke Progress assumes 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 11-B Firm Wholesale Purchased Power Contracts

DEC Aggregated Firm Wholesale Purchased Power Contracts			
Capacity Designation	**Summer Capacity (MW)**	**Location**	**Volume of Purchases (MWh) Jul 16-Jun 17**
Base	56	NC	488,480
Intermediate	2	NC	8,378
Peaking	63	NC	22,347
Base	86	SC	607,962
Peaking	3	SC	0
Peaking	8	System	12,645

Notes:

- **EOP: End of study period.**
- **Data represented above represents contractual agreements. Future expected consumption may differ from historic actuals.**

12. CROSS-REFERENCE OF IRP REQUIREMENTS AND SUBSEQUENT ORDERS:

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

Table 12-A Cross-Reference Table

Requirement	Location	Reference	Updated
B. REQUIREMENTS FOR THE DEVELOPMENT AND COMPOSITION OF THE IRP FILING			
1. Environmental costs are to be considered on a monetized basis where sufficient data is available. Those environmental costs that cannot be monetized must be addressed on a qualitative basis within the planning process. Environmental costs are to be considered within the IRP to the extent that they impact. the utility's specific system costs such as meeting existing regulatory standards and such standards as ran be reasonably anticipated to occur. The term "reasonably anticipated to occur" refers to standards that are in the process of being developed and are known to be forthcoming but are not finalized at the time of analysis. This does not mean that. the utility is prohibited from incorporating factors which go beyond the above definition. Should the utility feel that other factors (environmental or other) are important and need to be incorporated within the planning process, it needs to justify within the IRP the basis for inclusion. a. Environmental costs should be monetized and included within the planning process whenever possible. To the extent that environmental costs cannot be monetized the utility must consider them on a qualitative basis in developing the plan. The same guideline applies to relevant utility and customer costs. b. Each utility must provide the general environmental standards applicable to each supply-side option and explain the impact of each supply-side option on compliance with the standards. To the extent feasible each utility should seek to identify on a quantitative basis the impact of	Ch. 2, 4, 7	SC § 58-37-10	Yes

Table 12-A Cross-Reference Table (cont.)

demand-side options on the environment (i.e. reduced pollutant emissions, reduced waste disposal, increased noise pollution, etc.) Such impacts ran be reflected on a qualitative basis when quantitative information is not available. Each utility should identify and monetize, to the extent possible, the cost of compliance for existing and projected supply-side options.			
2. Each utility must. provide a demand forecast (to include both summer and winter peak demand) and an energy forecast. Forecasting requirements for the IRP filing: a. Forecast must incorporate explicit treatment of demand-side resources. b. Forecasting methodologies should seek to incorporate "end-use" modeling techniques where they are appropriate. End-use and econometric modeling techniques can be combined where appropriate to seek accuracy while being able to address the impacts of demand-side options. c. The IRP filing must incorporate energy and peak demand forecasts that include an explanation of the forecasting methodology and modeling procedures. d. The IRP filing must incorporate summary statistics for major models; assumptions followed within the forecasting process; projected energy usage by customer class; load factors by customer class; and total system sales. The utility must file this information, either as part of the IRP or as supplemental material to the IRP. e. An analysis must be performed to assess forecast uncertainty. This can consist of a high, most likely, low scenario analysis. f. The utility should periodically test its forecasting methodology for historical accuracy. g. The utility must identify significant changes in forecasting methodology.	Ch. 2, 4, 5, 7, 8	SC § 58-37-10	Yes

Table 12-A Cross-Reference Table (cont.)

3. The IRP filing must include a discussion of the risk associated with the plan (risk assessment). Where feasible the impacts of potential deviations from the plan should be identified.	Ch. 1, 2, 4, 7, 8, 9	SC § 58-37-10	Yes
4. The transmission improvements and/or additions necessary to support the IRP will also be provided within the plan. This includes listing the transmission lines and other associated facilities (125 kv or more) which are under construction or proposed, including the capacity and volt. age levels, locations, and schedules for completion and operation.	Ch. 4	SC § 58-37-10	Yes
5. The plan must incorporate an evaluation and review of the existing demand-side options utilized the utility. It should identify changes in objectives and specifically identify and quantify achievements within each specific program. plan should include a description of each objectives; implementation schedule; achievements to date. An explanation be provided outlining the approaches used to measure achievements and benefits.	Ch. 6	SC § 58-37-10	Yes
6. The IRP filing must identify and discuss any significant studies being conducted by the company on future demand-side and/or supply-side options.	Ch. 2, 3, 4, 6, 7, 8, 9	SC § 58-37-10	Yes
7. The IRP must be flexible to allow for the unknowns and uncertainties that confront the plan. The IRP must have the ability to quickly adapt to changes in a manner consistent with minimizing costs while maintaining reliability.	Ch. 2, 4, 7, 8	SC § 58-37-10	Yes
8. The utilities must incorporate as part of their IRP's a maintenance and refurbishment program of existing units when economically viable and consistent with system reliability and planning flexibility.	3, 4, 7, 8, 10	SC § 58-37-10	Yes
9. Utilities must adequately consider all cost effective third-party power purchases including firm, unit, etc., consistent with the IRP objective statement. This involves consideration of both interconnected and non-interconnected third-party purchases. The utility will describe any consideration of joint planning with other utilities. The utility will identify all third party power purchase agreements.	Ch. 2, 4, 7	SC § 58-37-10	Yes

Table 12-A Cross-Reference Table (cont.)

10. The IRP filing must identify any major problems the *utility* anticipates that have the potential to impact the success of the plan and the planning process. Strategies which might be invoked to deal with each problem should be identified whenever possible.	Ch. 2, 4, 7, 8	SC § 58-37-10	Yes
11. Each utility must demonstrate that the IRP incorporates not only efficient and cost. effective generation resources but also that transmission and distribution system costs are consistent with the minimization of total system costs. Any supporting information can be filed as a supplement to the IRP.	Ch. 3, 4, 8	SC § 58-37-10	Yes
12. Each utility must explain and/or describe any technologies included in the IRP.	Ch. 7	SC § 58-37-10	Yes
13. Each future supply-side option incorporated within the identified. fuel source; anticipated generating capacity; anticipated date of initial construction; anticipated date of commercial operation; etc. provided for each option. Utility shall identify the anticipated location of future supply-side option it is consistent with the utility's proprietary interests.	Ch. 2, 4, 7, 8, 9	SC § 58-37-10	Yes
14. The IRP must demonstrate that each utility is pursuing those resource options available for less than the avoided costs of new supply-side alternatives. Demand-side options will included in the IRP to the extent they are cost-effective are consistent with the Commission objective statement for the IRP. Utility DSM plans shall give attention to capturing lost opportunity resources. They include those cost effective energy efficiency savings that can only be realized during a narrow time period, such as in new construction, renovation, and in routine replacement of existing equipment.	Ch. 6	SC § 58-37-10	Yes