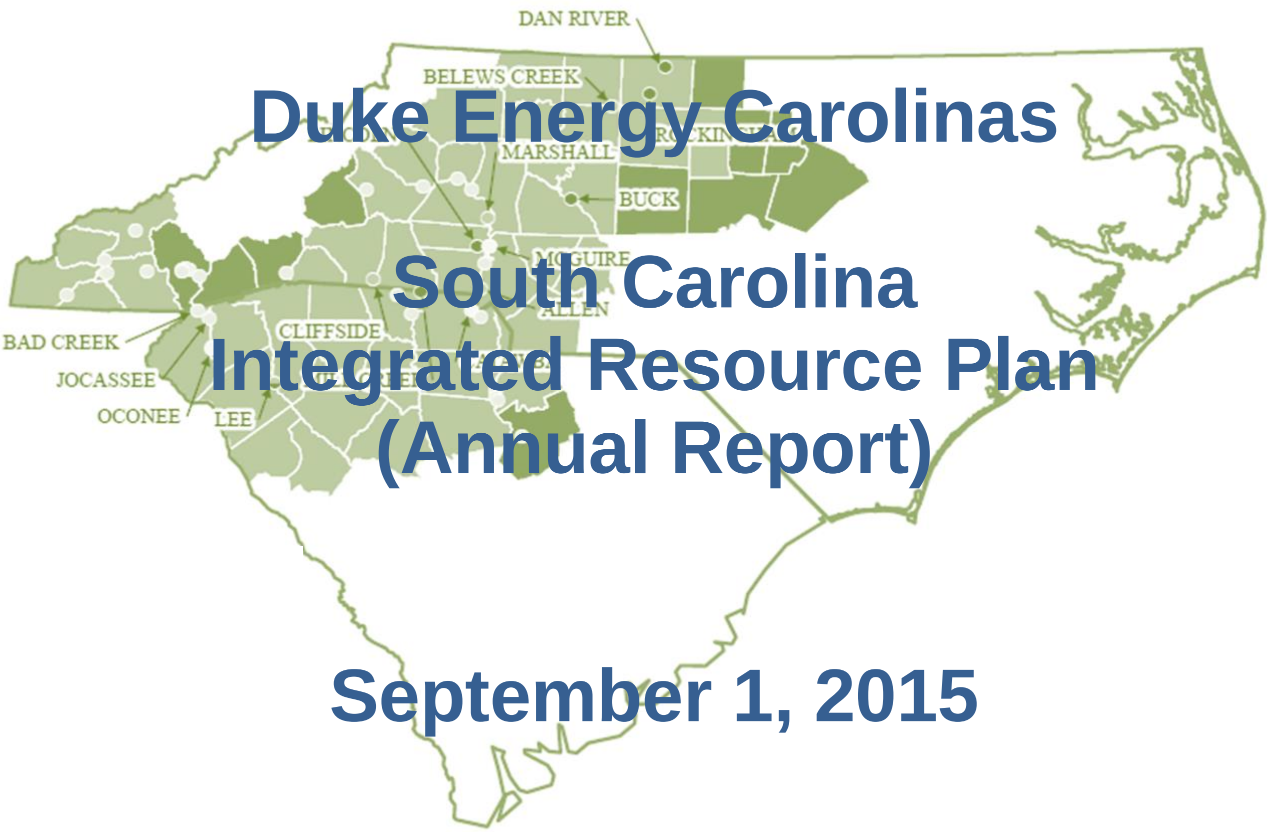
Duke Energy Carolinas

South Carolina
Integrated Resource Plan
(Annual Report)



September 1, 2015

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1. INTRODUCTION:

For more than a century, Duke Energy Carolinas (DEC) has provided affordable and reliable electricity to customers in South Carolina (SC) and North Carolina (NC) now totaling more than 2.4 million in number. The Company continues to serve its customers by planning for future demand requirements in the most reliable and economic way possible.

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. 91-885 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.

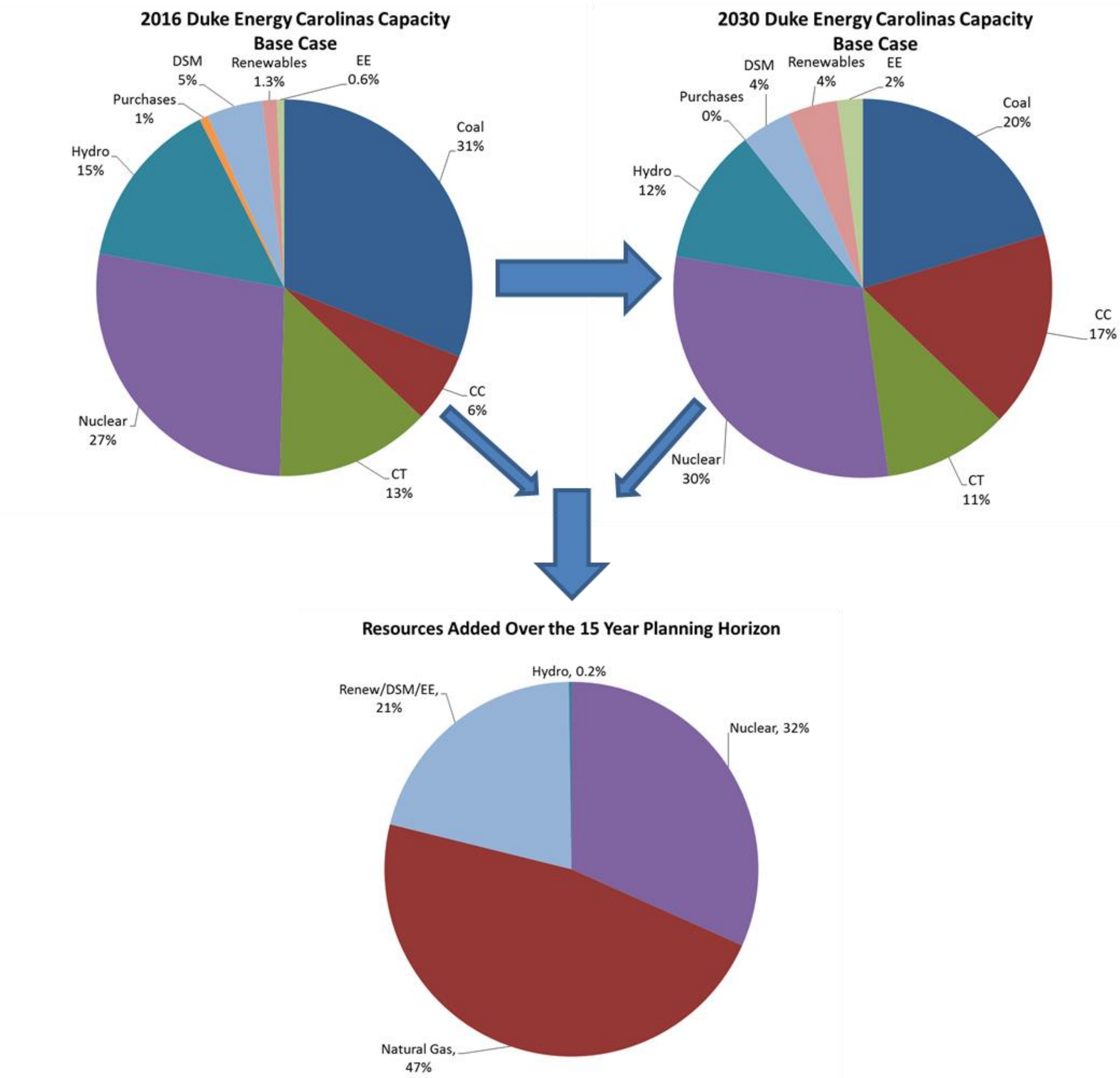
The Company files separate 2015 IRPs for South Carolina and North Carolina. However, the IRP analyzes the system as one DEC utility across both states including customer demand, energy efficiency (EE), demand side management (DSM), renewable resources and traditional supply-side resources. As such, the 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. 2015 IRP SUMMARY:

As 2015 is an update year for the IRP, DEC developed two cases based on the results of the 2014 IRP. The first case, or the "Base Case" is an update to the presented Base Case in the 2014 IRP which includes the expectation of carbon legislation beginning in 2020. Additionally, a "No Carbon Sensitivity" was developed in which no carbon legislation is considered. All results presented in this IRP represent the Base Case, except where otherwise noted.

As shown in the IRP Base Case plan, projected incremental needs are driven by load growth and the retirement of aging coal-fired resources. The 2015 IRP seeks to achieve a reliable, economic long term power supply through a balance of incremental renewable resources, EE, DSM, nuclear, and traditional supply-side resources planned over the coming years. In order to reliably and affordably meet our customers' needs into the future, the Company projects the need for incremental investments in these resources as depicted in the charts below.

Chart 2-A 2016 and 2030 Base Case Summer Capacity Mix and Sources of Incremental Capacity



The additional assets included over the 15 year planning horizon were selected as the most reliable and affordable resource mix to meet customer demand into the future. Furthermore, the selected mix of renewable resources, EE programs, DSM programs, nuclear generation, and state-of-the-art natural gas facilities also help the Company to maintain a diversified resource mix while reducing the environmental footprint associated with each unit of energy production.

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 by a mix of additional resources that reliably and cost effectively meet the load obligation and planning reserve margin while complying with all environmental and regulatory requirements. It should be noted that DEC considers the non-firm energy purchases and sales associated with the Joint Dispatch Agreement (JDA) with 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.

The use of a 17% reserve margin represents an increase over last year's IRP and is discussed in more detail in Chapter 4. As discussed in Chapter 4, this increase does not materially impact the near-term resource needs of the Company as projected in the Short-Term Action Plan but rather influences the subsequent years of the plan.

For the 2015 Update IRP, the Company presents a Base Case with a CO_2 tax beginning in 2020. The current assumption of a CO_2 tax is intended to serve as a placeholder for future carbon regulation. Consistent with this assumption, the final Environmental Protection Agency (EPA) Clean Power Plan (CPP) was released in mid-August and each state is in the process of developing individual state plans to comply with the rule as discussed in Chapter 4. Furthermore, a primary focus of this update IRP is the Short-Term Action Plan (STAP) which runs from 2016 to 2020. It was determined that the inclusion of the CO_2 tax did not have a significant impact on the STAP, and therefore the majority of the data presented in this report is taken from the CO_2 case (Base Case).

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

Duke Energy Carolinas
South Carolina
2015 IRP Update Report
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Figure 3-A Simplified IRP Process

Data Inputs:

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

Production Cost Modeling:

> Update Portfolios from Previous IRP
  > Base Case w/ CO_2
  > Base Case w/o CO_2

Significant Changes:

> Since 2014 IRP

Short-Term Action Plan:

> Detailed Discussion of 2016 through 2020

15-Year Resource Plan:

> 2016 through 2030

4. SIGNIFICANT CHANGES FROM THE 2014 IRP:

As an initial step in the IRP process, all production cost modeling data is updated to include the most current and relative data. Throughout the year, best practices are implemented to ensure the IRP best represents the Company's 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 newly included or updated data elements that had the most substantial impact on the 2015 IRP is provided below.

a) Load Forecast:

The 2015 DEC Spring Load Forecast is updated to include the most current data. The process and models for the load forecast remain the same, however the method by which utility energy efficiency (UEE)[1] impacts are incorporated into the load forecast has changed since the 2014 IRP. UEE programs are energy efficiency programs that were developed and offered to customers by the Company. The impacts of UEE on the load forecast do not include load reductions from free-riders. Free-riders are those customers who would have adopted the energy efficiency program regardless of incentives provided by the Company.

Program lives of UEE programs were previously considered indefinite in the IRP process, but in this year's IRP, are more clearly incorporated in the load forecast. Many UEE programs have a finite program life, much like the useful life of any generating resource. By including the useful life of the programs, the Company is better able to account for the UEE programs available to the DEC system, and as such, represent a more realistic and accurate representation of these programs. A numerical representation of the impacts of these changes and impacts to the load forecast are included in Chapter 5.

In the development of the load forecast, many variables may cause the load forecast projection to change. A brief comparison of the growth of the DEC load forecast is presented in Table 4-A and a more detailed discussion can be found in Chapter 5.

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

Table 4-A 2015 Load Forecast Growth Rates vs. 2014 Load Forecast Growth Rates (Retail and Wholesale Customers)

	2015 Forecast (2016 – 2030)			2014 Forecast (2015 – 2029)		
	Summer Peak Demand	**Winter Peak Demand**	**Energy**	**Summer Peak Demand**	**Winter Peak Demand**	**Energy**
Excludes impact of new EE programs	1.5%	1.5%	1.2%	1.8%	1.8%	1.5%
Includes impact of new EE programs	1.4%	1.4%	1.2%	1.4%	1.5%	1.0%

b) Renewable Energy:

On June 2, 2014, Gov. Nikki Haley signed into law Act 236, the South Carolina Distributed Energy Resource Program (SC DERP). The law permits utilities to participate in a voluntary program through which the utility may invest in or contract for new renewable generation capacity equivalent to as much as 3% of the utility's previous 5-year average peak. On July 15, 2015, Duke Energy Carolinas received approval of a portfolio of initiatives designed to increase the capacity of renewable generation located in its service area to approximately 84,000 kW(ac) by January 1, 2021. Eighty-four thousand kilowatts approximates two percent (2%) of the Company's estimated average South Carolina retail peak demand over the previous five year period and would enable the Company to meet the renewable generation goals of Act 236. The Company anticipates that the majority of this capacity will be solar photovoltaic (PV). Upon completion of the 84,000 kW goal, the Company has the option to invest in an additional 44,000 kW(ac) of renewable capacity before 2021, which approximates one percent (1%) of the Company's estimated average South Carolina retail peak demand over the previous five year period in 2020. The Company is committed to meeting the increasing goals of the SC DERP through 2020, and this has been reflected in the 2015 IRP.

Additionally, the Company is committed to full compliance with the North Carolina Renewable Energy Portfolio Standard (NC REPS). Currently signed projects and additional resources needed to fully comply with NC REPS are included in the 2015 IRP. There is currently a large influx of solar resources in the interconnection queue in the DEC system. With this influx, more solar projects are utilized to meet the NC REPS general compliance requirement, replacing biomass and wind that were represented in the 2014 IRP.

Finally, growing customer demand for renewable generation is driving the need for additional solar resources. These resources are included as Green Source projects and are projected in the IRP. Such projects are incremental to SC DERP and NC REPS compliance renewables. Green Source projects include expected projects, whether Company-owned or procured that will increase the capacity of renewable generation on the DEC system.

As mentioned above, DEC has seen a large influx of solar resources in the interconnection queue. A summary of the projects currently in the interconnection queue is represented in Table 4-B. The table shows not only the amount of resources, but also the type of resources.

Table 4-B DEC QF Interconnection Queue

Utility	Facility State	Energy Source Type	Number of Pending Projects	Pending Capacity MW AC
DEC	**NC**	Biogas	2	6
		Hydroelectric	2	4
		Landfill Gas	2	3
		Solar	165	845
	NC Total		**171**	**858**
	SC	Biomass	1	0
		Solar	4	20
	SC Total		**5**	**20**
DEC Total			**176**	**878**

c) Addition of Combined Heat & Power (CHP) to the IRP:

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

Duke Energy is exploring and working with potential customers with good base thermal loads on a regulated Combined Heat and Power offer. The CHP asset will be included as part of Duke Energy's IRP as a placeholder for future projects as described below. The steam sales are credited back to the revenue requirement of the projects to reduce the total cost of this generation grid resource. Along with the potential to be a competitive cost generation resource, CHP can result in CO_2 emission reductions, and present economic development opportunities for the state.

Projections for CHP have been included in the following quantities in the 2015 IRP:

2018: 20 MW
2020: 20 MW

As CHP continues to be pursued, future IRP processes will incorporate additional CHP, as appropriate.

Additional technologies evaluated as part of the 2015 IRP are discussed in Chapter 7.

d) <u>Reserve Margin:</u>

In 2012, DEC and DEP (the Companies) hired Astrape Consulting to conduct a reserve margin study for each utility. Astrape conducted a detailed resource adequacy assessment that incorporated the uncertainty of weather, economic load growth, unit availability and transmission availability for emergency tie assistance. Astrape analyzed the optimal planning reserve margin based on providing an acceptable level of physical reliability and minimizing economic costs to customers. The most common physical metric used in the industry is to target a system reserve margin that satisfies the one day in 10 years Loss of Load Expectation (LOLE) standard. This standard is interpreted as one firm load shed event every 10 years due to a 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 of loss of power. Thus, there is an economic optimum point where the cost of additional reserves plus the cost of reliability events to customers is minimized. Based on past reliability assessments, results of the Astrape analysis, and to enhance consistency and communication regarding reserve targets, both DEC and DEP had adopted a 14.5% minimum summer planning reserve margin for scheduling new resource additions.

In 2015, DEC and DEP have contracted again with Astrape Consulting to perform an updated resource adequacy study. The Companies believe that the study was warranted at this time due to several factors. First, the severe, extreme weather experienced in the service territory the last two winter periods was so impactful to the systems that additional review with the inclusion of recent years' weather history was warranted. Second, since the last reliability study the system has added, and projects to add, a large amount of resources that provide meaningful capacity benefits in the summer only. From a peak reduction perspective such summer oriented resources include solar generation, HVAC load control and chiller uprates to existing natural gas combined cycle units. The interconnection queue for solar facilities shows potential to add significantly to the solar resources already incorporated in the system.

Initial results of this updated study indicate that a 17% summer planning reserve margin is required to maintain the one day in 10 year LOLE standard. As such, DEC has utilized a 17% planning reserve margin in the 2015 IRP as opposed to the 14.5% reserve margin used in the 2014 IRP. However, preliminary findings also indicate that a summer-only reserve margin target may not be adequate for providing long term reliability given the increasing levels of summer-only resources. Additional study is needed to determine whether dual summer/winter planning reserve margin targets are required in the future. Once the final results are determined, any changes will be included in the 2016 IRP.

Adequacy of Projected Reserves

DEC's resource plan reflects summer reserve margins ranging from 17.0% to 25.6%. Reserves projected in DEC's IRP meet the minimum planning reserve margin target and thus satisfy the one day in 10 years LOLE criterion. The projected reserve margin exceeds the minimum 17% target by 3% or more in in 2022, 2028 and 2030 as a result of the economic addition of large combined cycle facilities in those years. Also, the reserve margin exceeds the minimum target by 3% in 2024 through 2027 due to the addition of baseload nuclear units in 2024 and 2026.

The IRP provides general guidance in the type and timing of resource additions. Since capacity is generally added in large blocks to take advantage of economies of scale, it should be noted that projected planning reserve margins in years immediately following new generation additions will often be somewhat higher than the minimum target. Large resource additions are deemed economic only if they have a lower Present Value Revenue Requirement (PVRR) over the life of the asset as compared to smaller resources that better fit the short-term reserve margin need. Development of detailed self-build projects and utilization of the Request for Proposals (RFP) process to consider purchased power alternatives will ensure the Company selects the most cost-effective resource additions. Reserves projected in DEC's IRP are appropriate for providing an economic and reliable power supply.

e) <u>Fuel Costs:</u>

In the 2014 IRP, the first 5 years of natural gas prices were based on market data and the remaining years were based off of fundamental pricing. 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 markets view of spot prices for a given point in the future. Fundamental prices developed through external econometric modeling, represent a projection of fuel prices into the future taking into account changing supply and demand assumptions of the external marketplace. The natural gas market has become more liquid, and there are now multiple buyers and sellers of natural gas in the marketplace that are willing to transact at longer transaction terms. Due to the evolving natural gas market, DEC and DEP are using market based prices for the first 10 years of the planning period (2016 – 2025). Following the 10 years of market prices, the Companies transition to fundamental pricing over a 5 year period with 100% fundamental pricing in 2030 and beyond.

As in the 2014 IRP, coal prices continue to be based on 5 years of market data in the 2015 IRP. In order to account for the impact on coal prices by using a longer market based natural gas price, the Companies are transitioning to fundamental coal pricing over a 10 year period (2021 to 2030), using the same growth rate as natural gas through that time period. Previously the Companies moved to fundamental coal prices once market prices were unavailable, but the Companies believe this creates an unrealistic disconnect between coal and natural gas prices in the medium term.

f) <u>EPA Clean Power Plan (CPP):</u>

On August 3, 2015, the EPA signed the final CO_2 emission limits rule for existing fossil-fuel power plants, known as the Clean Power Plan. The regulation is promulgated under Section 111(d) of the Clean Air Act and is sometimes referred to as 111(d). The rule is both lengthy (over 1550 pages) and complex. There have been considerable legal questions raised since the initial proposal and the rule remains controversial both at the state and federal levels.

EPA has made substantial changes from the proposed rule it released in June 2014 and a complete analysis will take time. The rule maintains a building block approach and preserves the first three building blocks of heat rate improvement re-dispatch to natural gas and construction of renewables. Building block 4, which in the proposal established energy efficiency targets, has been eliminated from the final rule. There are new elements in the final rule including additional compliance options, a model trading program and a "clean energy incentive program" to encourage early investments in renewable generation and demand-side energy efficiency.

Regulation under Section 111(d) of the Clean Air Act requires EPA to set the program requirements in a guideline document it issues to the states. The document must include:

"An emission guideline that reflects the application of the best system of emission reduction … that has been adequately demonstrated for designated facilities," taking into account both the "cost of achieving such emission reductions" as well as the "remaining useful life of sources."

States use the EPA guidance document to develop their own regulations – often referred to as a state implementation plan (SIP). States have primary implementation and enforcement authority and responsibility for the regulation.

State emission reduction goals were calculated based on EPA's determination of the "Best System of Emission Reduction" (BSER) for existing plants. Since no technology is commercially available to reduce CO_2 emissions at fossil fueled power plants, EPA proposed that the application of building blocks across the entire electric generation system was appropriate for determining the degree of emission reduction that would be achievable.

States have until September 6, 2016 to submit a complete plan or a partial plan with an extension request. States receiving an extension must submit a final state implementation plan (SIP) by September 6, 2018. EPA plans to take one year to review state plans (this could be a significant challenge for the Agency to accomplish). Duke Energy's compliance obligations will be finalized once a state compliance plan has been approved. If a state chooses not to submit a plan or a plan is deemed to be inadequate, EPA will impose a federal plan on the state.

South Carolina

The South Carolina 2030 rate target increased from 772 lbs. CO_2/MWh (proposed rule) to 1,156 lbs./MWh (final rule). In addition, the final rule includes a 2030 mass cap for South Carolina of 25,998,968 tons of CO_2. The SC Department of Health and Environmental Control has a robust stakeholder group evaluating options and intends to apply for the two year extension, pushing back the date for submittal of a final rule to September 2018. Duke Energy operates no coal-fired generation in South Carolina, so the impact of the rule is anticipated to be minimal.

North Carolina

The North Carolina 2030 rate target increased from 992 lbs. CO_2/MWh (proposed rule) to 1,136 lbs./MWh (final rule). In addition, the final rule includes a 2030 mass cap for North Carolina of 51,266,234 tons of CO_2. It remains unclear if this increased rate will make it easier or more difficult to comply given the uncertainty surrounding the treatment of new natural gas combined cycle (NGCC) units. Early indications are that the NC Department of Environment and Natural Resources will pursue submittal of a final plan based on what utilities can achieve at the individual affected unit, referred to as 'Building Block 1', to the EPA by the September 2016 deadline. With seven operational coal-fired stations and a growing fleet of NGCC units, the final rule and implementation plan will certainly impact generation in North Carolina, but the extent of these impacts remains unclear.

g) Transmission Planned or Under Construction:

This section contains the planned transmission line additions since the 2014 IRP. Only those projects added since the 2014 IRP are included. Additionally, a discussion of the system adequacy of DEC's transmission system is included. Table 4-C lists the line projects that are planned to meet reliability needs.

Table 4-C: DEC Transmission Line Additions

	Location		Capacity	Voltage	
Year	**From**	**To**	**MVA**	**KV**	**Comments**
2017	Ripp Switching Station	Riverbend Steam Station	N/A	230	Install new switching station along the Ripp - Riverbend 230kV transmission line to tie in new NTE generation.
2016	Peach Valley Tie	Riverview Switching Station	N/A	230	Install a switchable 3% series reactor on the Peach Valley – Riverview 230 kV transmission line.
2019	Foothills 500/230 kV Tie (New)	Duke Energy Progress Asheville Plant 230 kV station	1008	230	Construct a new 45 mile double circuit 230 kV transmission line with 1533 ACSS at 200°C
2022	Central Tie	Shady Grove Tie	930	230	Re-conductor approximately 18 miles of the Central – Shady Grove 230 kV transmission line with bundled 954 ACSR at 120°C.

The Foothills 500/230 kV Tie is included in the DEC transmission plan based on a Transmission Service Request (TSR) from DEP as part of DEP's Western Carolinas Modernization Project (WCMP). The details of the WCMP are discussed in DEP's 2015 IRP

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 South Carolina Electric & Gas (SCE&G) and Santee Cooper under a number of mechanisms including legacy interchange agreements between SCE&G, Santee Cooper, DEP and DEC.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with DEC's Transmission Planning Guidelines for voltage and thermal loading. The annual screening uses methods that comply with Southeastern Reliability Corporation (SERC) policy and North American Electric Reliability Corporation (NERC) Reliability Standards and the screening results identify the need for future transmission system expansion and upgrades.

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

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

- Assess the interconnected system's capability to handle large firm and non-firm transactions for purposes of economic access to resources and system reliability;
- Ensure that planned future transmission system improvements do not adversely affect neighboring systems; and
- Ensure interconnected system compliance with NERC Reliability Standards.

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

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

5. LOAD FORECAST:

The Duke Energy Carolinas' Spring 2015 Forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2016 – 2030 and represents the needs of the following customer classes:

- Residential
- Commercial
- Industrial
- Other Retail
- Wholesale

Energy projections are developed with econometric models using key economic factors such as income, electricity prices, industrial production indices, along with weather and appliance efficiency trends. Population is also used in the Residential customer model. While regression analysis has consistently yielded reasonable results over the years, processes are continually reviewed and compared between jurisdictions in an effort to improve upon the load forecasting process. Large unforeseen events, however, such as the "great recession" or the loss of large wholesale customers, will cause forecasts to differ from actual results.

The economic projections used in the Spring 2015 Forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of South Carolina and North Carolina.

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

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

The usage per customer forecast was derived using a Statistical Adjusted End-Use Model (SAE). This is a regression based framework that uses projected appliance saturation and efficiency trends developed by Itron using Energy Information Administration (EIA) data. It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models. The outlook for usage per customer is essentially flat through much of the forecast horizon, so most of the growth is primarily due to customer increases. The projected growth rate of Residential in the

Spring 2015 Forecast after all adjustments for UEE programs, Solar and Electric Vehicles from 2016-2030 is 1.3%.

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. Commercial is expected to be the fastest growing Class, with a projected growth rate of 1.5%, after all adjustments.

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

County population projections are obtained from the South Carolina Budget and Control Board as well as the North Carolina Office of State Budget and Management. These are then used to derive the total population forecast for the counties that comprise the DEC service area.

Weather impacts are incorporated into the models by using Heating Degree Days and Cooling Degree Days with a base temperature of 65 degrees. The forecast of degree days is based on a 10-year average.

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

Peak demands were projected using the SAE approach in the Spring 2015 Forecast. The peak forecast was developed using a monthly SAE model, similar to the sales SAE models, which includes monthly appliance saturations and efficiencies, interacted with weather and the fraction of each appliance type that is in use at the time of monthly peak.

Assumptions:

Below are the projected average annual growth rates of several key drivers from DEC's Spring 2015 Forecast:

	2016-2030
Real Income	2.7%
Mfg. IPI	2.1%
Population	1.0%

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.

Wholesale:

The wholesale contracts that are included in the load forecast are listed in Table 9-A in Chapter 9.

Historical Values:

It should be noted that the long-term structural decline of the Textile industry and the recession of 2008-2009 have had an adverse impact on DEC sales. 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 sales are given. As a note, the values in Table 5-B are not weather adjusted.

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

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Residential	1,840	1,877	1,916	2,012	2,024	2,034	2,041	2,053	2,068	2,089
Commercial	311	317	322	334	331	333	335	337	339	342
Industrial	7	7	7	7	7	7	7	7	7	7
Other	13	13	13	14	14	14	14	14	14	15
Total	2,171	2,214	2,259	2,367	2,377	2,389	2,397	2,411	2,428	2,452

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

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Residential	26,108	25,816	27,459	27,335	27,273	30,049	28,323	26,279	26,895	27,976
Commercial	25,679	26,030	27,433	27,288	26,977	27,968	27,593	27,476	27,765	28,421
Industrial	25,495	24,535	23,948	22,634	19,204	20,618	20,783	20,978	21,070	21,577
Other	269	271	278	284	287	287	287	290	293	303
Total Retail	77,550	76,653	79,118	77,541	73,741	78,922	76,985	75,022	78,035	78,278
Wholesale	1,580	1,694	2,454	3,525	3,788	5,166	4,866	5,176	5,824	6,559
Total System	79,130	78,347	81,572	81,066	77,528	84,088	81,851	80,199	83,859	84,837

<u>Utility Energy Efficiency:</u>

A new process for reflecting the impacts of UEE Programs UEE on the forecast was introduced in the Spring of 2015. In the latest forecast, the concept of ‘Program Life’ for a program was included in the calculations. For example, if the accelerated benefit of a residential UEE program is expected to have occurred 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 models framework, the naturally occurring appliance efficiency trends replace the rolled off UEE benefits serving to continue to reduce the forecasted load resulting from energy efficiency adoption.

The table below illustrates this process.

- Column A: Total energy demand for DEC before any reduction for UEE
- Column B: Total incremental cumulative UEE
- Column C: Roll-off amount of the historical UEE programs
- Column D: Roll-off amount of the incremental future UEE programs
- Column E: Total net UEE benefits (column B less columns C & D
- Column F: Total DEC energy demand after incorporating UEE (column A less column E)

Table 5-C UEE Program Life Process (MWh)

	A	B	C	D	E	F
	Forecast Before EE	Total Cumulative EE	Roll-Off Historical UEE	Roll-Off Forecasted UEE	UEE to Subtract From Forecast	Forecast After UEE
2015	97,982,308	2,873,708	47,012	0	2,826,696	95,155,613
2016	99,917,423	3,271,121	174,381	0	3,096,740	96,820,683
2017	101,531,374	3,674,346	459,003	0	3,215,343	98,316,032
2018	103,285,531	4,079,047	802,259	0	3,276,788	100,008,743
2019	103,351,876	4,487,148	1,172,938	0	3,314,210	100,037,666
2020	104,654,462	4,895,248	1,480,766	15,527	3,398,955	101,255,507
2021	105,711,347	5,303,349	1,776,255	56,283	3,470,811	102,240,536
2022	106,993,783	5,711,449	2,013,612	144,371	3,553,466	103,440,317
2023	108,272,081	6,119,549	2,207,592	263,372	3,648,585	104,623,496
2024	109,759,123	6,527,650	2,344,071	432,850	3,750,730	106,008,393
2025	110,943,675	6,935,750	2,401,759	711,975	3,822,016	107,121,660
2026	112,334,984	7,343,851	2,421,015	1,055,253	3,867,583	108,467,401
2027	113,696,808	7,751,951	2,421,015	1,443,797	3,887,138	109,809,670
2028	115,344,683	8,160,051	2,421,015	1,842,280	3,896,756	111,447,927
2029	116,722,458	8,568,152	2,421,015	2,247,713	3,899,424	112,823,034
2030	117,890,622	8,691,375	2,421,015	2,655,580	3,614,780	114,275,842

Note: UEE Data is net of free riders

Results:

Tabulations of class forecasts of customers and sales are given in Table 5-D and Table 5-E. The sales forecasts are after all adjustments for UEE, Solar and Electric Vehicles.

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

	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2016	2,139	348	7	15	2,510
2017	2,164	353	7	15	2,540
2018	2,188	358	7	15	2,568
2019	2,212	362	7	16	2,596
2020	2,234	366	7	16	2,623
2021	2,257	370	7	16	2,651
2022	2,280	375	7	16	2,678
2023	2,303	380	7	16	2,706
2024	2,326	384	7	16	2,733
2025	2,349	389	7	17	2,761
2026	2,371	394	7	17	2,789
2027	2,394	398	7	17	2,816
2028	2,417	403	7	17	2,844
2029	2,440	408	7	17	2,872
2030	2,462	413	7	17	2,899

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

	Residential Gwh	Commercial Gwh	Industrial Gwh	Other Gwh	Retail Gwh
2016	27,871	29,033	31,922	294	79,119
2017	28,162	29,390	22,095	291	79,936
2018	28,508	29,811	22,298	287	80,904
2019	28,858	30,261	22,471	282	81,872
2020	29,234	30,724	22,668	277	82,903
2021	29,573	31,080	22,851	271	83,774
2022	29,975	31,527	23,041	264	84,807
2023	30,355	31,983	23,233	258	85,829
2024	30,811	32,524	23,417	252	87,004
2025	31,144	32,989	23,612	246	87,990
2026	31,573	33,525	23,818	241	89,156
2027	32,022	34,067	23,998	235	90,322
2028	32,546	34,714	24,231	230	91,721
2029	32,990	35,306	24,418	225	92,939
2030	33,448	35,900	24,633	219	94,201

Tabulations of the utility's forecasts, 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-G and 5-H.

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

The values in these tables reflect the loads that Duke Energy Carolinas is contractually obligated to provide and cover the period from 2016 to 2030.

For the period 2016-2030, the Spring 2015 Forecast resulted in the following growth rates:

Table 5-F Growth Rates of Retail and Wholesale Customers (2016-2030)

	2015 Forecast (2016 – 2030)		
	Summer Peak Demand	**Winter Peak Demand**	**Energy**
Excludes impact of new EE programs	1.5%	1.5%	1.2%
Includes impact of new EE programs	1.4%	1.4%	1.2%

The peaks and sales in the tables and charts below are at the generator, except for the Class sales forecast, which is at the meter.

Table 5-G Load Forecast without Energy Efficiency Programs & Before Demand Reduction Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2016	18,764	17,972	99,917
2017	19,129	18,330	101,531
2018	19,566	18,735	103,286
2019	19,659	18,846	103,352
2020	19,992	19,133	104,654
2021	20,296	19,449	105,711
2022	20,607	19,687	106,994
2023	20,908	19,959	108,272
2024	21,217	20,259	109,759
2025	21,524	20,543	110,944
2026	21,810	20,851	112,335
2027	22,131	21,134	113,697
2028	22,462	21,476	115,345
2029	22,770	21,797	116,722
2030	23,125	22,105	117,891

Chart 5-A Load Duration Curve without Energy Efficiency Programs & Before Demand Reduction Programs

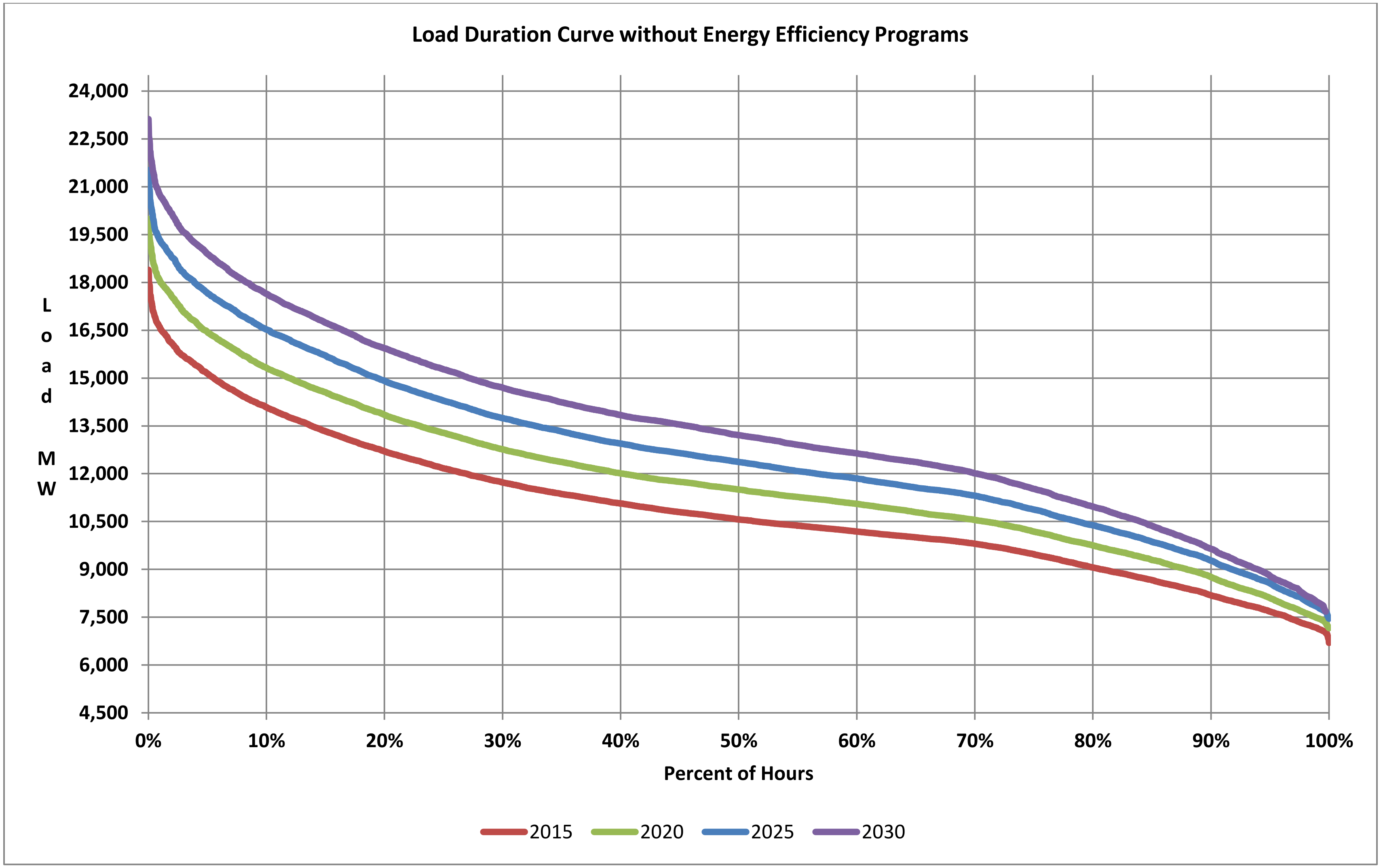
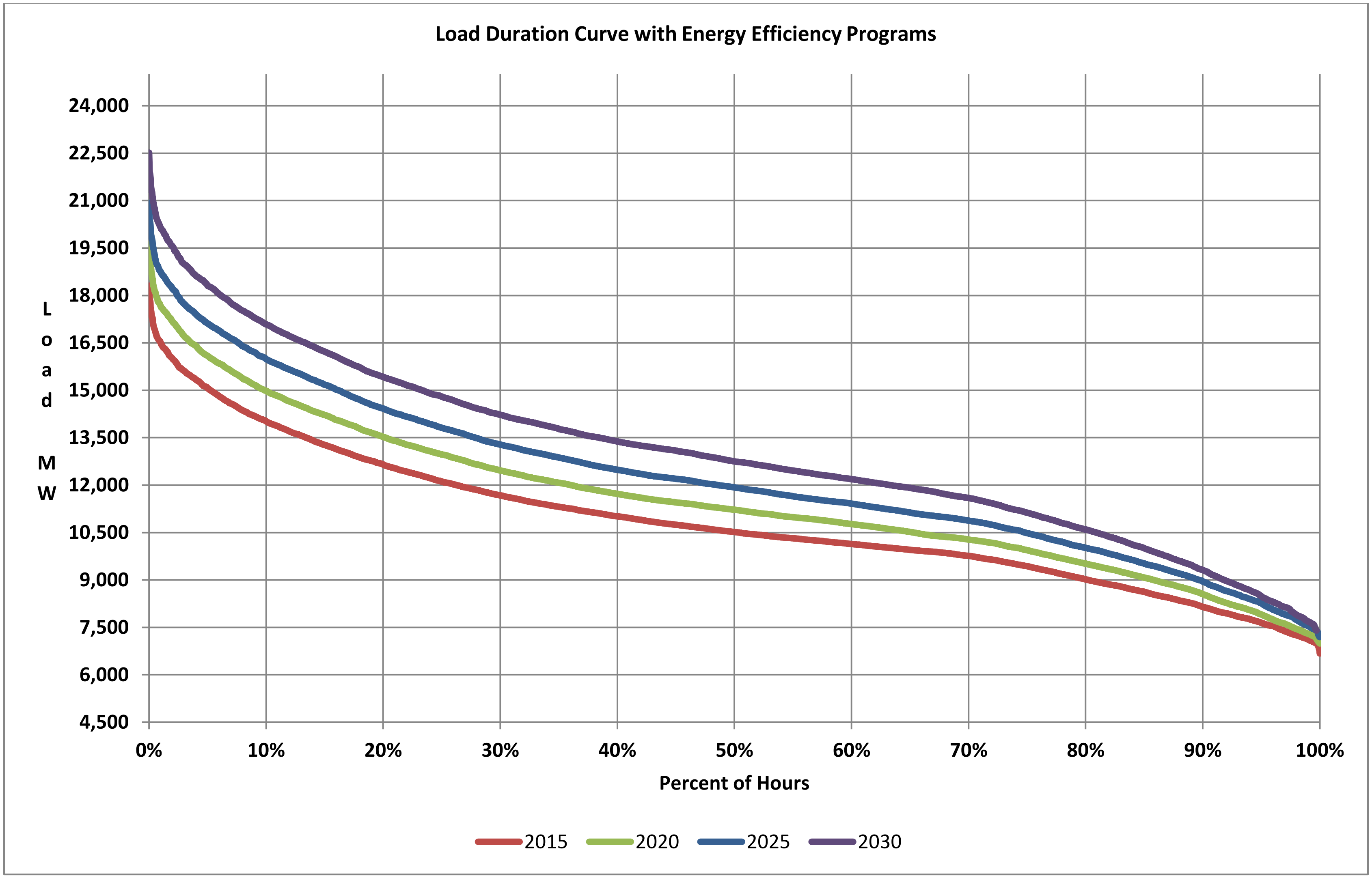


Table 5-H Load Forecast with Energy Efficiency Programs & Before Demand Reduction Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2016	18,625	17,896	96,821
2017	18,927	18,213	98,316
2018	19,303	18,579	100,009
2019	19,334	18,651	100,038
2020	19,611	18,878	101,256
2021	19,859	19,156	102,241
2022	20,121	19,360	103,440
2023	20,377	19,602	104,623
2024	20,649	19,877	106,008
2025	20,934	20,145	107,122
2026	21,209	20,445	108,467
2027	21,527	20,726	109,810
2028	21,859	21,067	111,448
2029	22,164	21,386	112,823
2030	22,517	21,693	114,276

Chart 5-B Load Duration Curve with Energy Efficiency Programs & Before Demand Reduction Programs



6. ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT:

Current Energy Efficiency and Demand-Side Management Programs

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

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

Residential Customer Programs

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

Non-Residential Customer Programs

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

- PowerShare®
- PowerShare® CallOption

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

Pilot Program:

- Energy Management and Information Services Program

Energy Efficiency Programs

These programs are typically non-dispatchable education or incentive programs. Energy and capacity savings are achieved by changing customer behavior or through the installation of more energy-efficient equipment or structures. All cumulative effects (gross of Free Riders, at the Plant[2]) since the inception of these existing programs through the end of 2014 are summarized below. Please note that the cumulative impacts listed below include the impact of any Measurement and Verification (M&V) performed since program inception. The following provides more detail on DEC's existing EE programs:

Residential Programs:

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

Appliance Recycling Program			
Cumulative as of:	**Participants**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2014	21,030	21,001	2,891

[2] "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.

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

Home Energy House Call			
Cumulative as of:	**Participants**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2014	39,803	39,421	6,652

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

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

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

Energy Efficiency Education Program			
Cumulative as of:	**Participants**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2014	109,350	28,397	4,697

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

- Energy Efficient Pool Equipment: This measure encourages the purchase and installation of energy efficient equipment and controls. Initially, the measure will focus on variable speed pumps, but the pool equipment offerings may evolve with the marketplace to include additional equipment options and control devices that reduce energy consumption and/or demand.
- Energy Efficient Lighting: This measure encourages the installation of energy efficient lighting products and controls. The product examples may include, but are not limited to the following: standard CFLs, specialty CFLs, A lamp LEDs, specialty LEDs, CFL fixtures, LED fixtures, 2X incandescent, LED holiday lighting, motion sensors, photo cells, timers, dimmers and daylight sensors.
- Energy Efficient Water Heating and Usage: This measure encourages the adoption of heat pump water heaters, insulation, temperature cards and low flow devices.
- Other Energy Efficiency Products and Services: Other cost-effective measures may be added to in-home installations, purchases, enrollments and events. Examples of additional measures may include, without limitation, outlet gaskets, switch gaskets, weather stripping, filter whistles, fireplace damper seals, caulking, smart strips and energy education tools/materials.

Residential Smart $aver® Program – Residential CFLs			
Cumulative as of:	**Participants (CFLs)**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2014	28,542,160	1,173,014	124,682

Residential Smart $aver® Program – Specialty Lighting			
Cumulative as of:	**Participants (bulbs)**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2014	549,494	23,833	2,879

Residential Smart $aver® Program – Water Measures			
Cumulative as of:	**Measures**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2014	96,911	6,575	524

Residential Smart $aver® Program – Pool Equipment			
Cumulative as of:	**Measures**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2014	89	221	56

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

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

Residential Smart $aver® Program -- HVAC			
Cumulative as of:	**Participants**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2014	58,881	48,104	12,380

Residential Smart $aver® Program -- Tune and Seal			
Cumulative as of:	**Participants**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2014	1,457	783	238

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

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

Residential Smart $aver® Program – Property Manager CFLs			
Cumulative as of:	**Participants (CFLs)**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2014	987,897	42,588	4,386

Residential Smart $aver® Program – Multi Family Water Measures			
Cumulative as of:	**Participants (Measures)**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2014	84,242	9,052	723

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

My Home Energy Report Program			
Cumulative as of:	**Participants**	**Capability (MWh)**	**Summer Capability (kW)**
December 31, 2014	748,303	146,012	39,424

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

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

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

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

Income Qualified Energy Efficiency and Weatherization Program			
Cumulative as of:	**Participants**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2014	26,045	12,119	1,819

Non-Residential:

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

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

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

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

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

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

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

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

Non-Residential Smart $aver® Program			
Cumulative as of:	**Measures**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2014	2,942,356	1,055,182	170,446

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 Program			
Cumulative as of:	**Participants (KWh@meter)**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2014	4,023,251	4,231	1,023

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 Program			
Cumulative as of:	**Participants (KWh@meter)**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2014	20,768,337	22,060	4,591

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

Smart Energy Now Pilot			
Cumulative as of:	**Participants**	**Energy Savings (MWh)**	**Peak Demand (kW)**
December 31, 2014	70	41,064	1,315

<u>Pilot:</u>

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

This Pilot was never implemented and was removed from the EE portfolio in 2015.

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:

<u>Residential:</u>

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

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

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

Power Manager Program			
As of:	**Participants (customers)**	**Devices (switches)**	**Summer 2014 Capability (MW)**[3]
December 31, 2014	157,188	187,471	464

The following table shows Power Manager® program activations that were not for testing purposes from June 1, 2011 through December 31, 2014.

Power Manager® Program Activations*			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**[4]
June 21, 2011 – 2:30 PM	June 21, 2011 – 5:00 PM	150	101
July 11, 2011 – 2:30 PM	July 11, 2011 – 6:00 PM	210	101
July 13, 2011 – 2:30 PM	July 13, 2011 – 6:00 PM	210	102
July 20, 2011 – 2:30 PM	July 20, 2011 – 5:00 PM	150	108
July 21, 2011 – 2:30 PM	July 21, 2011 – 5:00 PM	150	115
July 29, 2011 – 2:30 PM	July 29, 2011 – 5:00 PM	150	110
August 2, 2011 – 3:30 PM	August 2, 2011 – 6:00 PM	150	115
June 29, 2012 – 2:30 PM	June 29, 2012 – 5:00 PM	150	152
July 9, 2012 – 1:30 PM	July 9, 2012 – 5:00 PM	210	113
July 17, 2012 – 2:30 PM	July 17, 2012 – 5:00 PM	150	141
July 26, 2012 – 2:30 PM	July 26, 2012 – 6:00 PM	210	143
July 27, 2012 – 1:30 PM	July 27, 2012 – 4:00 PM	150	152
July 18, 2013 – 2:30 PM	July 18, 2013 – 5:00 PM	150	116
July 19, 2013 – 1:30 PM	July 19, 2013 – 4:00 PM	150	112
July 24, 2013 – 1:30 PM	July 24, 2013 – 4:00 PM	150	150

[3] *MW value "at the generator" using conversion factor of 1.062187*
[4] *MW Load Reduction is the average load reduction "at the generator" over the event period for full clock hours using conversion factor of 1.062187*

Power Manager® Program Activations* cont.			
Start Time	**Start Time**	**Start Time**	**Start Time**
August 12, 2013 – 1:30 PM	August 12, 2013 – 4:00 PM	150	158
August 29, 2013 – 1:30 PM	August 29, 2013 – 4:00 PM	150	157
September 10, 2013 – 2:30 PM	September 10, 2013 – 5:00 PM	150	143
September 11, 2013 – 2:30 PM	September 11, 2013 – 5:30 PM	180	123
June 5, 2014 – 1:00 PM	June 5, 2014 – 3:00 PM	120	155
June 10, 2014 – 3:00 PM	June 10, 2014 – 5:00 PM	120	213
June 18, 2014 – 3:30 PM	June 18, 2014 – 5:00 PM	90	217
September 2, 2014 – 2:30 PM	September 2, 2014 – 6:00 PM	210	272
September 11, 2014 – 2:30 PM	September 11, 2014 – 6:00 PM	210	275
September 16, 2014 – 2:30 PM	September 16, 2014 – 6:00 PM	210	274

Non-Residential:

Demand Response – Interruptible Programs and Related Rate Structures:

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

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

IS Program		
As of:	**Participants**	**Summer 2014 Capability (MW)**[5]
December 31, 2014	56	134

The following table shows IS program activations that were not for testing purposes from June 1, 2011 through December 31, 2014.

[5] *MW value "at the generator" using conversion factor of 1.062187*

IS Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**[6]
June 1, 2011 – 1:00 PM	June 1, 2011 – 6:00 PM	300	156
July 12, 2011 – 1:00 PM	July 12, 2011 – 5:00 PM	240	133
January 7, 2014 6:30 AM	January 7, 2014 11:00 AM	270	133
January 8, 2014 6:00 AM	January 8, 2014 10:00 AM	240	149

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

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

SG Program		
As of:	**Participants**	**Summer 2014 Capability (MW)**[7]
December 31, 2014	30	14

The following table shows SG program activations that were not for testing purposes from June 1, 2011 through December 31, 2014.

SG Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**[8]
June 1, 2011 – 1:00 PM	June 1, 2011 – 6:00 PM	300	55
July 12, 2011 – 1:00 PM	July 12, 2011 – 5:00 PM	240	45
January 7, 2014 6:30 AM	January 7, 2014 11:00 AM	270	28
January 8, 2014 6:00 AM	January 8, 2014 10:00 AM	240	33

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

[6] *MW Load Reduction is the average load reduction "at the generator" over the event period for full clock hours using conversion factor of 1.062187*
[7] MW value "at the generator" using conversion factor of 1.062187
[8] *MW Load Reduction is the average load reduction "at the generator" over the event period for full clock hours* using conversion factor of 1.062187

(PowerShare® Voluntary) and a combined emergency and economic option that allows for increased notification time of events (PowerShare® CallOption).

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

PowerShare® Mandatory Program		
As of:	**Participants**	**Summer 2014 Capability (MW)**[9]
December 31, 2014	186	370

The following table shows PowerShare® Mandatory program activations that were not for testing purposes from June 1, 2011 through December 31, 2014.

PowerShare® Mandatory Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**[10]
June 1, 2011 – 1:00 PM	June 1, 2011 – 6:00 PM	300	334
July 12, 2011 – 1:00 PM	July 12, 2011 – 5:00 PM	240	339
January 7, 2014 6:30 AM	January 7, 2014 11:00 AM	270	281
January 8, 2014 6:00 AM	January 8, 2014 10:00 AM	240	354

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 2014 Capability (MW)**[11]
December 31, 2014	9	26

The following table shows PowerShare® Generator program activations that were not for testing purposes from June 1, 2011 through December 31, 2014.

[9] *MW value "at the generator" using conversion factor of 1.062187*
[10] *MW Load Reduction is the average load reduction "at the generator" over the event period for full clock hours using conversion factor of 1.062187*
[11] *MW value "at the generator" using conversion factor of 1.062187*

PowerShare® Generator Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**[12]
June 1, 2011 – 1:00 PM	June 1, 2011 – 6:00 PM	300	17
July 12, 2011 – 1:00 PM	July 12, 2011 – 5:00 PM	240	13
January 7, 2014 6:30 AM	January 7, 2014 11:00 AM	270	12
January 8, 2014 6:00 AM	January 8, 2014 10:00 AM	240	13

In response to EPA regulations finalized January 2013, the manner in which PowerShare Generator is dispatched was modified to allow customers with emergency generators to continue participation in demand response programs. To comply with the new rule, dispatch of the PowerShare Generator program must be limited to NERC Level II (EEA2) except for the monthly readiness tests. More recently, on May 1, 2015, the DC Circuit Court of Appeals entered a decision against the EPA questioning the merits of portions of the generator regulations including allowance of 100 hours of annual participation in demand response. Vacatur of the 100-hour provision could result in the inability of DEC to offer a cost-effective emergency generator program because the original rule only allowed for 12 hours of DR participation annually. Therefore, the Company will continue to monitor the impact of court proceedings on the regulations and will make appropriate adjustments to program offerings.

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

PowerShare® Voluntary Program		
As of:	**Participants**	**Summer Capability (MW)**[13]
December 31, 2014	5	N/A

The following table shows PowerShare® Voluntary program activations that were <u>not</u> for testing purposes from June 1, 2011 through December 31, 2014.

[12] *MW Load Reduction is the average load reduction "at the generator" over the event period for full clock hours using conversion factor of 1.062187*
[13] *MW value "at the generator" using conversion factor of 1.062187*

PowerShare® Voluntary Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**[14]
June 1, 2011 – 1:00 PM	June 1, 2011 – 9:00 PM	480	2
June 2, 2011 – 2:00 PM	June 2, 2011 – 8:00 PM	360	16
July 20, 2011 – 1:00 PM	July 20, 2011 – 7:00 PM	360	2
July 21, 2011 – 1:00 PM	July 21, 2011 – 7:00 PM	360	2
July 22, 2011 – 11:00 AM	July 22, 2011 – 4:00 PM	300	4
August 3, 2011 – 2:00 PM	August 3, 2011 – 7:00 PM	300	2
January 23, 2014 – 6:00 AM	January 23, 2014 – 11:00 AM	300	16

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

PowerShare® CallOption Program		
As of:	**Participants**	**Summer 2014 Capability (MW)**[15]
December 31, 2014	0	0

The following table shows PowerShare® CallOption program activations that were not for testing purposes from June 1, 2011 through December 31, 2014.

PowerShare® CallOption Program Activations			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**[16]
July 27, 2012 – 1:00 PM	July 27, 2012 – 9:00 PM	480	0.2

[14] *MW Load Reduction is the average load reduction "at the generator" over the event period for full clock hours using conversion factor of 1.062187*
[15] *MW value "at the generator" using conversion factor of 1.062187*
[16] *MW Load Reduction is the average load reduction "at the generator" over the event period for full clock hours using conversion factor of 1.062187*

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

The program was not available for customer participation until January 1, 2014.

PowerShare® CallOption Program		
As of:	**Participants**	**Summer Capability (MW)**
December 31, 2014	0	N/A

The table below incorporates December 31, 2014 participation levels for demand response programs and the capability of these programs projected for the summer of 2015.

Demand Side Management Programs and Capability		
Program Name	**Program Participation as of 12/31/14**	**2014 Estimated Summer IRP Capability (MW)**
IS	56	163
SG	30	20
PowerShare® Mandatory	186	345
PowerShare® Generator	9	44
PowerShare® Voluntary	5	N/A
PowerShare® CallOption	-	-
Total	**286**	**574**
Power Manager® (Switches)	187,471	433
Grand Total	**-**	**1,007**

Source: 2015 DEC IRP Forecast (Base Case)

Future EE and DSM Programs:

DEC is continually seeking to enhance its EE and DSM portfolio by: (1) adding new programs or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new M&V results, and (3) other EE pilots. .[17]

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

Two programs currently being developed for filing and approval are Residential HVAC Referrals program and Small Business Demand Response. Both of these programs have been presented to the DSM Collaborative and final preparation of the actual filing documents was underway at the time this IRP was being created. However, because these programs have not yet been approved by the Commissions, the expected impacts from these programs have not been included in this year's analysis of generation needs

EE and DSM Program Screening:

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

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

- The UCT compares utility benefits (avoided costs) to the costs incurred by the utility to implement the program, and does not consider other benefits such as participant savings or

[17] DEC has not included "Pay As You Go" as a potential EE program at this time. The Company will make a determination regarding the viability of an associated EE program upon completion of the Pilot Program.

societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs, and load (line) losses.

- The RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program.

- The TRC Test compares the total benefits to the utility and to participants relative to the costs to the utility to implement the program along with the costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test, however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC.

- The Participant Test evaluates programs from the perspective of the program's participants. The benefits include reductions in utility bills, incentives paid by the utility and any State, Federal or local tax benefits received.

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

Energy Efficiency and Demand-Side Management Program Forecasts:

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

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

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

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

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

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

In response to these Recommendations above, the company has included the following information.

Forecast Methodology:

In 2011, DEC commissioned a new EE market potential study to obtain new estimates of the technical, economic and achievable potential for EE savings within the DEC service area. The final report was prepared by Forefront Economics Inc. and H. Gil Peach and Associates, LLC and was completed on February 23, 2012 and included an achievable potential for planning year 5 and an economic potential for planning year 20.

The Forefront study results are suitable for IRP purposes and for use in long-range system planning models. This study also helps to inform utility program planners regarding the extent of EE opportunities and to provide broadly defined approaches for acquiring savings. This study did not, however, attempt to closely forecast EE achievements in the short-term or from year to year. Such an annual accounting is highly sensitive to the nature of programs adopted as well as the timing of the introduction of those programs. As a result, it was not designed to provide detailed specifications and work plans required for program implementation. The study provides part of the picture for planning EE programs. Fully implementable EE program plans are best developed considering this study along with the experience gained from currently running programs, input from DEC program managers and EE planners, feedback from the DSM Collaborative and with the possible assistance of implementation contractors.

As part of its annual planning process, DEC created a detailed Base Case forecast of its EE and DSM portfolio for the upcoming 5 year planning horizon. In addition, DEC also developed a long run load forecast for the next 25 years under the assumption that no incremental new Utility sponsored EE would be implemented. This "before EE" forecast was then used to project the long run Economic potential for DEC based on the results of the Market Potential Study by multiplying the Load Forecast times the expected Economic Potential as a percentage of Retail sales. This

Economic Potential was further adjusted to account for the cumulative actual EE portfolio achievements since the creation of the Market Potential Study. This overall Economic Potential was then multiplied times an Achievable Potential factor consistent with information provided in the most recent energy efficiency market potential study conducted by EPRI[18].

Using this Achievable Potential as an upper boundary for the cumulative EE Achievement along with the projection of the first 5 years (2015-19) from the Company's annual planning process, a long run EE forecast was created by extrapolating the incremental achievements for Year 5 (2019) until such time as the cumulative EE Achievement, including actual achievement since the analysis performed in the Market Potential Study, reached the Achievable Potential factor of approximately 60% of the Economic Potential. In the forecast, after inclusion of approximately 1,533 GWh achieved since 2011, the projected EE achievement reaches this level by the year 2029.

For periods beyond 2029, the annual incremental EE achievements were set to maintain the same percentage achievement of the Economic Potential, i.e. the achievements were set to essentially keep up with the growth in the retail sales forecast.

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 Gross and Net of Free Riders basis (responsive to Recommendation Number 10 above). The Company assumes total EE savings will continue to grow on an annual basis throughout the planning period until reaching approximately 60% of the Economic Potential in approximately 2029, 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, in response to Recommendation Number 12 above, this table includes a column that shows historical EE program savings since the inception of the EE programs in 2009 through the end of 2014, which accounts for approximately an additional 2,702 GWh of energy. These projections also do not include savings from DEC's proposed Integrated Voltage-VAR Control program, which will be discussed later in this document.

[18] http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001025477

Base Case MWh Load Impacts of EE Programs

Year	Annual MWh Load Reduction - Gross		Annual MWh Load Reduction - Net	
	Including measures added in 2015 and beyond	Including measures added since 2009	Including measures added in 2015 and beyond	Including measures added since 2009
2009-14		2,701,707		2,423,095
2015	501,970	3,203,677	450,613	2,873,708
2016	953,597	3,655,303	848,027	3,271,121
2017	1,411,427	4,113,134	1,251,252	3,674,346
2018	1,870,848	4,572,554	1,655,953	4,079,047
2019	2,334,511	5,036,218	2,064,053	4,487,148
2020	2,798,175	5,499,881	2,472,154	4,895,248
2021	3,261,838	5,963,545	2,880,254	5,303,349
2022	3,725,502	6,427,208	3,288,354	5,711,449
2023	4,189,165	6,890,872	3,696,455	6,119,549
2024	4,652,829	7,354,535	4,104,555	6,527,650
2025	5,116,492	7,818,199	4,512,655	6,935,750
2026	5,580,156	8,281,862	4,920,756	7,343,851
2027	6,043,819	8,745,526	5,328,856	7,751,951
2028	6,507,483	9,209,189	5,736,957	8,160,051
2029	6,971,146	9,672,853	6,145,057	8,568,152
2030	7,111,146	9,812,853	6,268,280	8,691,375

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

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

Base Case Load Impacts of DSM Programs

Year	Annual Peak MW Reduction				
	IS	SG	PowerShare	PowerManager	Total Annual Peak
2015	163	21	389	433	1,007
2016	150	20	395	442	1,007
2017	142	19	406	448	1,015
2018	135	18	417	451	1,021
2019	129	17	427	451	1,024
2020	123	17	432	449	1,021
2021	121	16	432	449	1,018
2022	121	16	432	449	1,018
2023	121	16	432	449	1,018
2024	121	16	432	449	1,018
2025	121	16	432	449	1,018
2026	121	16	432	449	1,018
2027	121	16	432	449	1,018
2028	121	16	432	449	1,018
2029	121	16	432	449	1,018
2030	121	16	432	449	1,018

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

DEC's approved EE plan is consistent with the requirement set forth in the Cliffside Unit 6 CPCN Order to invest 1% of annual retail electricity revenues in EE and DSM programs, subject to the results of ongoing collaborative workshops and appropriate regulatory treatment.

However, pursuing EE and DSM initiatives is not expected to meet the incremental demand for electricity. DEC still envisions the need to secure additional generation, as well as cost-effective renewable generation, but the EE and DSM programs offered by DEC will address a significant portion of this need if such programs perform as expected.

EE Savings Variance since last IRP:

In response to Recommendation Number 9 from the Public Staff, the Base Case EE savings forecast of MW and MWh is within 10% of the forecast presented in the 2014 IRP when compared on the cumulative achievements at year 15 of the forecast as shown in the table below.

Base Case Comparison to 2014 IRP - Gross					
	2014 IRP		2015 IRP		
	Annual MWh Load Reduction		Annual MWh Load Reduction		
Year	Including measures added in 2014 and beyond	Including measures added since 2009	Including measures added in 2015 and beyond	Including measures added since 2009	% Change from 2014 to 2015 IRP
2014	439,799	2,646,334		2,701,707	2.1%
2015	845,866	3,052,401	501,970	3,203,677	5.0%
2016	1,272,833	3,479,369	953,597	3,655,303	5.1%
2017	1,712,712	3,919,247	1,411,427	4,113,134	4.9%
2018	2,161,679	4,368,214	1,870,848	4,572,554	4.7%
2019	2,637,421	4,843,957	2,334,511	5,036,218	4.0%
2020	3,119,267	5,325,803	2,798,175	5,499,881	3.3%
2021	3,670,534	5,877,069	3,261,838	5,963,545	1.5%
2022	4,272,614	6,479,150	3,725,502	6,427,208	-0.8%
2023	4,891,005	7,097,541	4,189,165	6,890,872	-2.9%
2024	5,489,403	7,695,938	4,652,829	7,354,535	-4.4%
2025	6,097,058	8,303,594	5,116,492	7,818,199	-5.8%
2026	6,607,562	8,814,097	5,580,156	8,281,862	-6.0%
2027	7,073,440	9,279,976	6,043,819	8,745,526	-5.8%
2028	7,490,168	9,696,704	6,507,483	9,209,189	-5.0%
2029	7,788,479	9,995,015	6,971,146	9,672,853	-3.2%
2030	8,029,871	10,236,407	7,111,146	9,812,853	-4.1%

Programs Evaluated but Rejected:

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

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

Duke Energy is pursuing implementation of grid modernization throughout the enterprise with a vision of creating a sustainable energy future for our customers and our business by being a leader of innovative approaches that will modernize the grid.

Duke Energy Carolinas is reviewing an Integrated Volt-Var Control (IVVC) project that will better manage the application and operation of voltage regulators (the Volt) and capacitors (the VAR) on the Duke Energy Carolinas distribution system. In general, the project tends to optimize the operation of these devices, resulting in a "flattening" of the voltage profile across an entire circuit, starting at the substation and continuing out to the farthest endpoint on that circuit. This flattening of the voltage profile is accomplished by automating the substation level voltage regulation and capacitors, line capacitors and line voltage regulators while integrating them into a single control system. This control system continuously monitors and operates the voltage regulators and capacitors to maintain the desired "flat" voltage profile. Once the system is operating with a relatively flat voltage profile across an entire circuit, the resulting circuit voltage at the substation can then be operated at a lower overall level. Lowering the circuit voltage at the substation results in an immediate reduction of system loading.

The deployment of an IVVC program for Duke Energy Carolinas is anticipated to take approximately 4 years following project approval. This IVVC program is projected to reduce future distribution-only peak needs by 0.20% in 2018, 0.4% in 2019, 0.6% in 2020, 1.0% in 2021 and beyond.

While the subject of grid modernization is very broad, only the supply and demand impacts of the IVVC program is included in the IRP process.

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 "No Carbon" sensitivity case.

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

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2015 Annual Plan

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Forecast															
1 Duke System Peak	18,811	19,176	19,613	19,706	20,039	20,296	20,607	20,908	21,217	21,524	21,810	22,131	22,462	22,770	23,125
Catawba Owner Backstand	47	47	47	47	47	0	0	0	0	0	0	0	0	0	0
2 Firm Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(140)	(202)	(263)	(325)	(381)	(438)	(486)	(531)	(568)	(590)	(601)	(604)	(603)	(606)	(608)
4 Adjusted Duke System Peak	**18,672**	**18,974**	**19,350**	**19,381**	**19,658**	**19,859**	**20,121**	**20,377**	**20,649**	**20,934**	**21,209**	**21,527**	**21,859**	**22,164**	**22,517**
Existing and Designated Resources															
5 Generating Capacity	20,368	20,389	20,734	21,104	21,114	21,120	21,120	21,120	21,120	21,120	21,120	21,120	21,120	19,993	19,993
6 Designated Additions / Uprates	21	345	670	10	6	0	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	0	(300)	0	0	0	0	0	0	0	0	0	(1,127)	0	0
8 Cumulative Generating Capacity	**20,389**	**20,734**	**21,104**	**21,114**	**21,120**	**21,120**	**21,120**	**21,120**	**21,120**	**21,120**	**21,120**	**21,120**	**19,993**	**19,993**	**19,993**
Purchase Contracts															
9 Cumulative Purchase Contracts	**228**	**223**	**217**	**177**	**172**	**86**	**68**	**56**	**46**	**46**	**37**	**37**	**35**	**10**	**2**
Non-Compliance Renewable Purchases	69	64	58	56	54	54	54	42	33	33	23	23	21	10	2
Non-Renewables Purchases	159	159	159	121	118	32	14	14	14	14	14	14	14	0	0
Undesignated Future Resources															
10 Nuclear	0	0	0	0	0	0	0	0	1,117	0	1,117	0	0	0	0
11 Combined Cycle	0	0	0	0	0	0	895	0	0	0	0	0	895	0	895
12 Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 CHP	0	0	20	0	20	0	0	0	0	0	0	0	0	0	0
Renewables															
14 Cumulative Renewables Capacity	212	200	202	459	708	961	1,044	1,057	1,079	1,093	1,110	1,122	1,140	1,160	1,171
15 Cumulative Production Capacity	**20,829**	**21,157**	**21,542**	**21,769**	**22,040**	**22,207**	**23,167**	**23,168**	**24,297**	**24,311**	**25,435**	**25,448**	**25,232**	**25,227**	**26,124**
Demand Side Management (DSM)															
16 Cumulative DSM Capacity	**1,056**	**1,064**	**1,097**	**1,127**	**1,151**	**1,202**	**1,202**	**1,202**	**1,202**	**1,202**	**1,202**	**1,202**	**1,202**	**1,202**	**1,202**
17 Cumulative Capacity w/ DSM	**21,885**	**22,221**	**22,639**	**22,897**	**23,191**	**23,409**	**24,369**	**24,370**	**25,499**	**25,513**	**26,637**	**26,650**	**26,434**	**26,429**	**27,326**
Reserves w/ DSM															
18 Generating Reserves	3,214	3,247	3,289	3,515	3,533	3,550	4,248	3,993	4,850	4,580	5,428	5,122	4,575	4,266	4,809
19 % Reserve Margin	**17.2%**	**17.1%**	**17.0%**	**18.1%**	**18.0%**	**17.9%**	**21.1%**	**19.6%**	**23.5%**	**21.9%**	**25.6%**	**23.8%**	**20.9%**	**19.2%**	**21.4%**

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

Winter Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2015 Annual Plan

	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Load Forecast														
1 Duke System Peak	18,019	18,377	18,782	18,846	19,180	19,449	19,687	19,959	20,259	20,543	20,851	21,134	21,476	21,797
2 Firm Sale	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(75)	(117)	(157)	(195)	(255)	(293)	(326)	(357)	(382)	(398)	(406)	(408)	(409)	(411)
4 Adjusted Duke System Peak	**17,943**	**18,260**	**18,626**	**18,651**	**18,925**	**19,156**	**19,360**	**19,602**	**19,877**	**20,145**	**20,445**	**20,726**	**21,067**	**21,386**
Existing and Designated Resources														
5 Generating Capacity	21,155	21,200	21,970	21,970	21,980	21,986	21,986	21,986	21,986	21,986	21,986	21,986	21,986	20,825
6 Designated Additions / Uprates	45	1,070	0	10	6	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	(300)	0	0	0	0	0	0	0	0	0	0	(1,161)	0
8 Cumulative Generating Capacity	**21,200**	**21,970**	**21,970**	**21,980**	**21,986**	**21,986**	**21,986**	**21,986**	**21,986**	**21,986**	**21,986**	**21,986**	**20,825**	**20,825**
Purchase Contracts														
9 Cumulative Purchase Contracts	**193**	**191**	**185**	**146**	**141**	**49**	**31**	**19**	**18**	**18**	**17**	**17**	**16**	**1**
Non-Compliance Renewable Purchases	28	26	20	19	17	17	17	5	4	4	3	3	2	1
Non-Renewables Purchases	165	165	165	127	124	32	14	14	14	14	14	14	14	0
Undesignated Future Resources														
10 Nuclear	0	0	0	0	0	0	0	0	1,117	0	1,117	0	0	0
11 Combined Cycle	0	0	0	0	0	0	935	0	0	0	0	0	935	0
12 Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 CHP	0	0	20	0	20	0	0	0	0	0	0	0	0	0
Renewables														
14 Cumulative Renewables Capacity	114	94	89	113	145	179	194	195	203	206	206	204	206	208
15 Cumulative Production Capacity	**21,507**	**22,255**	**22,264**	**22,259**	**22,312**	**22,254**	**23,185**	**23,174**	**24,298**	**24,302**	**25,417**	**25,415**	**25,191**	**25,178**
Demand Side Management (DSM)														
16 Cumulative DSM Capacity	**554**	**551**	**553**	**556**	**558**	**553**	**553**	**553**	**553**	**553**	**553**	**553**	**553**	**553**
17 Cumulative Capacity w/ DSM	**22,061**	**22,806**	**22,817**	**22,814**	**22,870**	**22,807**	**23,738**	**23,727**	**24,851**	**24,855**	**25,970**	**25,968**	**25,744**	**25,731**
Reserves w/ DSM														
18 Generating Reserves	4,118	4,546	4,191	4,163	3,946	3,651	4,378	4,125	4,974	4,710	5,525	5,242	4,677	4,345
19 % Reserve Margin	**22.9%**	**24.9%**	**22.5%**	**22.3%**	**20.8%**	**19.1%**	**22.6%**	**21.0%**	**25.0%**	**23.4%**	**27.0%**	**25.3%**	**22.2%**	**20.3%**

DEC - Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Summer Projections of Load, Capacity, and Reserves tables. All values are MW except where shown as a Percent.

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

   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 January 2015.

   Includes 101 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for NCMPA1 firm capacity sale.

6. A short-term 300 MW PPA is included in 2017, and removed in the fall of 2017.

   This PPA is a placeholder to ensure compliance with the minimum planning reserve margin and will be re-evaluated in the coming months.

   Lee Combined Cycle is reflected in 2018 (670 MW). This is the DEC capacity net of 100 MW to be owned by NCEMC.

   Capacity Additions include Duke Energy Carolinas hydro units scheduled to be repaired and returned to service. The units are returned to service in the 2016-2020 timeframe and total 17 MW.
   Also included is a 65 MW capacity increase due to nuclear uprates at Catawba, McGuire, and Oconee. Timing of these uprates is shown from 2016-2017.

7. The short-term 300 MW PPA is removed in the fall of 2017.

   A planning assumption for coal retirements has been included in the 2015 IRP.

   Allen Steam Station (1127 MW) is assumed to retire in 2028.

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

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.

8. Sum of lines 5 through 7.

9. Cumulative Purchase Contracts including purchased capacity from PURPA Qualifying Facilities, an 86 MW Cherokee County Cogeneration Partners contract which began in June 1998 and expires June 2020 and miscellaneous other QF projects.

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

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

10. New nuclear resources economically selected to meet load and minimum planning reserve margin.

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

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

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

    Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.
    Addition of 895 MW of combined cycle capacity in 2022, 2028 and 2030.

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

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

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 resources were selected in the Base Case.

13. New 20 MW combined heat and power units included in 2018 and 2020. The 2015 IRP represents the first time that CHP resources have been included in the IRP.

14. Cumulative solar, biomass, hydro and wind resources to meet NC REPS and SC DERP compliance.

    Also includes Green Source solar projects.

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 target planning reserve margin is 17%.

<u>Technologies Considered:</u>

Similar to the 2014 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 2015 IRP.

As in the 2014 IRP, the Company conducted an economic screening analysis of various technologies. Through the screening process the following technologies were considered as part of the more detailed quantitative analysis phase of the planning process in the 2015 IRP, with changes from the 2014 IRP highlighted and explained in further detail below.

- Base load – 723 MW Supercritical Pulverized Coal with CCS
- Base load – 525 MW IGCC with CCS
- Base load – 2 x 1,117 MW Nuclear units (AP1000)
- Base load – **895 MW** – 2x2x1 Advanced Combined Cycle (Inlet Chiller and Duct Fired)
- **Base load – 20 MW – CHP** (CT with HRSG)
- Peaking/Intermediate – **828 MW** 4-7FA CTs
- Renewable – 150 MW Wind - On-Shore
- Renewable – 5 MW Landfill Gas
- Renewable – 25 MW Solar Photovoltaic (PV)

Combined Cycle base capacities and technologies: Based on proprietary third party engineering studies, the 2x2x1 Advanced CC saw an increase in base load of 29 MWs. 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 an increase in base load of 36 MWs. 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 20-MW Combined Heat & Power units are considered in the 2015 IRPs and are included as resources for meeting future generation needs. Duke Energy is exploring and working with potential customers with good base thermal loads on a regulated CHP offer and, as CHP continues to be implemented, future IRP processes will incorporate additional CHP as appropriate.

In addition to the technologies listed above, Lithium-Ion (Li-ion) batteries with off-peak charging were considered in the screening process as an energy storage option. Energy Storage in the form or battery storage is becoming more feasible with the advances in battery technology and the reduction in battery cost; however, their uses have been concentrated on frequency regulation, solar smoothing, and/or energy shifting from localized renewable energy sources with a high incidence of intermittency (i.e. solar and wind applications).

Centralized generation will likely remain the backbone of the grid for Duke Energy in the long term; however, in addition to centralized generation it is possible that distributed generation will begin to share more and more grid responsibilities over time as technologies such as energy storage increase our grid's flexibility. At this point however, the screening analysis shows that costs are still prohibitive for large scale battery technologies to be considered in the IRP.

Expansion Plan and Resource Mix

A tabular presentation of the 2015 Base Case resource plan represented in the above LCR table is shown below:

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

Duke Energy Carolinas Resource Plan (1) Base Case - Summer				
Year	**Resource**		**MW**	
2016	Nuclear Uprates	Hydro Units Return to Service (2)	20	1
2017	Nuclear Uprates		45	
2018	Lee CC (3)	CHP	670	20
2019	Hydro Units Return to Service (4)		10	
2020	Hydro Units Return to Service (4)	CHP	6	20
2021	-		-	
2022	New CC		895	
2023	-		-	
2024	New Nuclear		1117	
2025	-		-	
2026	New Nuclear		1117	
2027	-		-	
2028	New CC		895	
2029	-		-	
2030	New CC		895	

Notes: (1) Table includes both designated and undesignated capacity additions
(2) Bryson City and Mission hydro units return to service
(3) Lee CC capacity is net of NCEMC ownership of 100 MW
(4) Rocky Creek Units currently offline for refurbishment; these are expected return to service dates

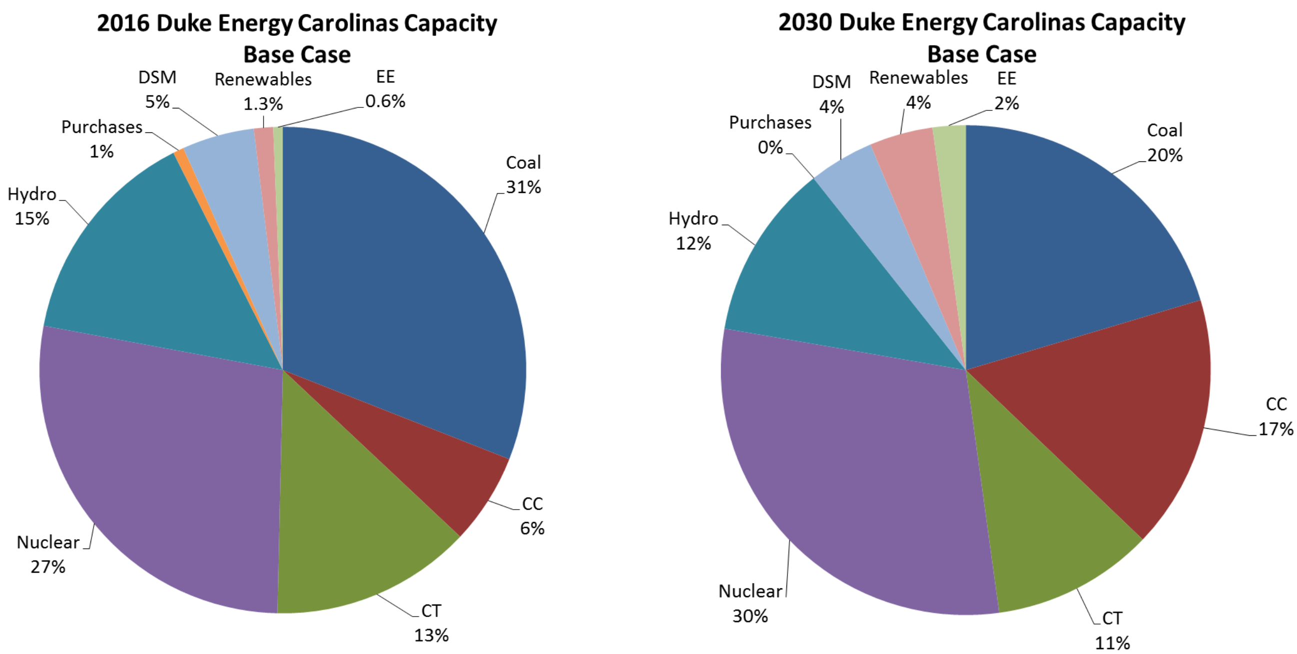
Table 7-D DEC Base Case Resources (with CO_2) Cumulative Summer Totals

DEC Base Case Resources
Cumulative Summer Totals - 2016 - 2030

Nuclear	2299
CC	3355
CT	0
Hydro	17
CHP	40
Total	5711

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 2030, the Base Case projects that DEC will have a smaller reliance on coal and a higher reliance on gas-fired resources, nuclear, renewable resources and EE as compared to the current state.

Chart 7-A 2016 & 2030 Base Case Summer Capacity Mix



As a sensitivity, the Company developed a No Carbon Price scenario (No Carbon Sensitivity). The expansion plan for this case is shown below in Table 7-E. Table 7-F summarizes the capacity additions for the No Carbon Sensitivity case by technology type.

Table 7-E No Carbon Sensitivity - Summer

Duke Energy Carolinas Resource Plan (1)
No Carbon Sensitivity - Summer

Year	Resource		MW	
2016	Nuclear Uprates	Hydro Units Return to Service (2)	20	1
2017	Nuclear Uprates		45	
2018	Lee CC (3)	CHP	670	20
2019	Hydro Units Return to Service (4)		10	
2020	Hydro Units Return to Service (4)	CHP	6	20
2021	-		-	
2022	New CC		895	
2023	-		-	
2024	-		-	
2025	New CC		895	
2026	-		-	
2027	New CT		414	
2028	New CT		1242	
2029	New CT		414	
2030	New CC		895	

Notes: (1) Table includes both designated and undesignated capacity additions
(2) Bryson City and Mission hydro units return to service
(3) Lee CC capacity is net of NCEMC ownership of 100 MW
(4) Rocky Creek Units currently offline for refurbishment; these are expected return to service dates

Table 7-F No Carbon Sensitivity Cumulative Summer Totals

DEC No Carbon Sensitivity Resources
Cumulative Summer Totals - 2016 - 2030

Nuclear	65
CC	3355
CT	2070
Hydro	17
CHP	40
Total	5547

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.

- Over the 5 year period represented by the Short-Term Action Plan, DEC projects to add an incremental 241 MW of EE, and 95 MW of DSM.

Continued Focus on Renewable Energy Resources:

- DEC is committed to full compliance with SC DERP in South Carolina and NC REPS in North Carolina. Due to pending expiries of Federal and State tax subsidies for solar development, 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 continues to evaluate market options for renewable generation and procure capacity, as appropriate. PPAs have been signed with developers of solar PV and landfill gas resources. Additionally, REC purchase agreements have been executed for purchases of unbundled RECs from wind, solar PV, solar thermal and hydroelectric facilities.

- In the 2015 IRP, over the 5 year period represented by the Short-Term Action Plan, DEC projects to add an incremental 1,093 MW of renewable resources (nameplate).

- DEC continues to pursue CHP opportunities, as appropriate.

Continue to Pursue New Nuclear:

Duke Energy Carolinas sees significant value in new nuclear generation. Today, nuclear and gas generation are effectively the only base load electrical generating options available for construction, and new nuclear generation is the only carbon-free, base load generation option available. Coupling that situation with Duke Energy's long term aspiration to reduce carbon dioxide emissions and the EPA's recently released Clean Power Plan, that value is patently evident. Furthermore, Oconee Nuclear Station's operating licenses expire in 2033-2034. The NRC is expected to finalize its guidance for Second License Renewal (SLR) in mid-2017. The Company believes Oconee Nuclear Station is an excellent candidate for SLR; however before a decision is made the scope, cost and complexity of required modifications, upgrades, and other improvements need to be fully understood and evaluated once the NRC issues its SLR guidance.

Duke Energy continues the work necessary to obtain combined construction and operating licenses (COLs) for the William States Lee III Nuclear Station (Lee Nuclear). The Lee COL application references and incorporates the Westinghouse AP1000 NRC certified design. As that design is refined and modified through Westinghouse's design finalization activities and construction of AP1000 units in China and the United States, a handful of issues have arisen that must be resolved by the Nuclear Regulatory Commission (NRC) prior to issuance of the Lee COL. Assuming no new significant issues are identified, issuance of the COL is expected by late 2016.

Given the long cycle times to license and build a new nuclear electric generation station, it is essential to continue the licensing work on Lee Nuclear as a hedge against extensive carbon dioxide regulation, uncertain load growth, volatile fuel prices, and the possibility of not relicensing the existing operating nuclear stations.

Addition of Clean Natural Gas Resources:

- Continue construction of the Lee combined cycle plant (Lee CC) at the Lee Steam Station site located in Anderson, SC. As demonstrated in recent IRP plans, a capacity need was identified in 2017/2018 to allow DEC to meet its customers' load demands. The Company received a Certificate of Environmental Compatibility and Public Convenience and Necessity (CECPCN) in an order dated May 2, 2014, to move forward with the construction of the Lee

CC. For the Lee CC project, site clearing and grubbing is complete and the project site is to grade. The engineering phase is approximately 50% complete through the end of June and the first foundation is planned to be placed by mid-August.

- Operate Lee Steam Station Unit 3 as a natural gas-fired unit. Lee Unit 3 was successfully converted to a natural gas-fired facility. This conversion was completed in April 2015. The unit was available for the summer peak of 2015.

Expiration of Wholesale Sales Contracts: (CONFIDENTIAL)

In the 2016-2020 timeframe, DEC has [redacted] of 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 Contracts Expiration (CONFIDENTIAL)

[redacted]

Expiration of Wholesale Purchase Contracts: (CONFIDENTIAL)

In the 2016-2020 timeframe, DEC has [redacted] of 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: (CONFIDENTIAL)

[redacted]

Continued Focus on System Reliability and Resource Adequacy for DEC System:

As previously stated, DEC has retained Astrape Consulting to conduct a reserve margin study to examine the resource adequacy of the DEC system. Based upon the recent extreme winter weather, the potential for continued extreme weather, and the large amount of expected summer-only resource additions, the Company felt that new examination of the reliability of the system and the adequacy of the resources was warranted.

Initial results of this updated study indicate that a 17% summer planning reserve margin is required to maintain the one day in 10 year LOLE. As such, DEC has utilized a 17% planning reserve margin in the 2015 IRP as opposed to the 14.5% reserve margin used in the 2014 IRP. However, preliminary findings also indicate that a summer-only reserve margin target may not be adequate for providing long term reliability given the increasing levels of summer-only resources. Additional study is needed to determine whether dual summer/winter planning reserve margin targets are required in the future. Once the final results are determined, any changes will be included in the 2016 IRP.

The 2015 IRP includes a placeholder for a short-term 300 MW purchased power agreement (PPA) in the summer of 2017 to satisfy the increase in the planning reserve margin to 17%. The need for this short-term PPA will be reevaluated after the reserve margin study is completed and there is greater certainty regarding reserve margin target(s), load and resource needs.

Continued Focus on Regulatory, Environmental Compliance & Wholesale Activities:

- Retire 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.

- Continue to be on target for compliance with the Cliffside 6 Air Quality Permit Plan by 2018:

    - Completed retirement of Buck, Riverbend, Dan River and Lee coal units.

    - Completed Bridgewater hydro units capacity increase.

    - EE, DSM, renewable energy, and nuclear uprates currently achieved combined with future projections continue to exceed the total annual required emission reduction by 2018.

    - Updated projected emission reductions based on the 2015 IRP are 9,298,091 tons of CO_2 equivalent emissions.

- Continue to prepare for the final rule of EPA's Clean Power Plan.

- Continue to investigate the future environmental control requirements and resulting operational impacts associated with existing and potential environmental regulations such as MATS, the Coal Combustion Residuals rule, the Cross-State Air Pollution Rule (CSAPR), 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 2015 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 occur. 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								
			Compliance Renewable Resources (Cumulative Nameplate MW)			Other Non-Compliance Renewables (Cumulative Nameplate MW) [4]		
Year	Retirements	Additions	Wind [2]	Solar [2]	Biomass/Hydro [3]	Solar/Biomass/Hydro	EE	DSM [5]
2016		20 MW Nuc 1.1 MW Hydro Units Return to Service[1]	0	212	101	153	140	1056
2017		45 MW Nuc 300 MW PPA [7]	0	219	81	154	202	1064
2018	300 MW PPA [7]	670 MW Lee CC [6] 20 MW CHP	0	227	74	158	263	1097
2019		10 MW Hydro Units [8] Return to Service	0	798	70	155	325	1127
2020		6 MW Hydro Units [8] Return to Service 20 MW CHP	0	1332	75	154	381	1151

Notes:

(1) Bryson City & Mission hydro units are currently offline for refurbishment; this is expected return to service date.

(2) Capacity is shown in nameplate ratings. For planning purposes, wind presents a 13% contribution to peak and solar has a 46% contribution to peak.

(3) Biomass includes swine and poultry contracts.

(4) Other renewables includes NUGs and Green Source Projects.

(5) Includes impacts of grid modernization.

(6) 670 MW is net of NCEMC portion of Lee CC.

(7) This is a summer PPA; PPA is a placeholder in the summer of the year needed to meet 17% minimum planning reserve margin, and removed in the fall of that same year.

(8) Rocky Creek Hydro units are currently offline for refurbishment; this is expected return to service date.

9. OWNED GENERATION:

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 2014, Duke Energy Carolinas' nuclear and coal-fired generating units met the vast majority of customer needs by providing 58% and 32%, respectively, of Duke Energy Carolinas' energy from generation. Hydroelectric generation, Combustion Turbine generation, Combined Cycle generation, solar generation, long term PPAs, and economical purchases from the wholesale market supplied the remainder.

The tables below list the Duke Energy Carolinas' plants in service in 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 January 1, 2015

Coal						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Allen	1	167	162	Belmont, NC	Coal	Intermediate
Allen	2	167	162	Belmont, NC	Coal	Intermediate
Allen	3	270	261	Belmont, NC	Coal	Intermediate
Allen	4	282	276	Belmont, NC	Coal	Intermediate
Allen	5	275	266	Belmont, NC	Coal	Intermediate
Belews Creek	1	1135	1110	Belews Creek, NC	Coal	Base
Belews Creek	2	1135	1110	Belews Creek, NC	Coal	Base
Cliffside	5	556	552	Cliffside, NC	Coal	Base
Cliffside	6	844	844	Cliffside, NC	Coal	Base
Marshall	1	380	380	Terrell, NC	Coal	Intermediate
Marshall	2	380	380	Terrell, NC	Coal	Intermediate
Marshall	3	658	658	Terrell, NC	Coal	Base
Marshall	4	660	660	Terrell, NC	Coal	Base
Total Coal		6,909	6,821			

Combustion Turbines						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Lee	7C	41	41	Pelzer, SC	Natural Gas/Oil-Fired	Peaking
Lee	8C	41	41	Pelzer, SC	Natural Gas/Oil-Fired	Peaking
Lincoln	1	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	2	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	3	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	4	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	5	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	6	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	7	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	8	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	9	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	10	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	11	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	12	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	13	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	14	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	15	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Lincoln	16	93	79.2	Stanley, NC	Natural Gas/Oil-Fired	Peaking
Mill Creek	1	92.4	74.4	Blacksburg, SC	Natural Gas/Oil-Fired	Peaking
Mill Creek	2	92.4	74.4	Blacksburg, SC	Natural Gas/Oil-Fired	Peaking
Mill Creek	3	92.4	74.4	Blacksburg, SC	Natural Gas/Oil-Fired	Peaking
Mill Creek	4	92.4	74.4	Blacksburg, SC	Natural Gas/Oil-Fired	Peaking
Mill Creek	5	92.4	74.4	Blacksburg, SC	Natural Gas/Oil-Fired	Peaking
Mill Creek	6	92.4	74.4	Blacksburg, SC	Natural Gas/Oil-Fired	Peaking
Mill Creek	7	92.4	74.4	Blacksburg, SC	Natural Gas/Oil-Fired	Peaking
Mill Creek	8	92.4	74.4	Blacksburg, SC	Natural Gas/Oil-Fired	Peaking
Rockingham	1	179	165	Rockingham, NC	Natural Gas/Oil-Fired	Peaking
Rockingham	2	179	165	Rockingham, NC	Natural Gas/Oil-Fired	Peaking
Rockingham	3	179	165	Rockingham, NC	Natural Gas/Oil-Fired	Peaking
Rockingham	4	179	165	Rockingham, NC	Natural Gas/Oil-Fired	Peaking
Rockingham	5	179	165	Rockingham, NC	Natural Gas/Oil-Fired	Peaking
Total NC		2,383	2,092.2			
Total SC		821.2	677.4			
Total CT		3,204	2,770			

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

Combined Cycle						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Buck	CT11	187.2	172.9	Salisbury, N.C.	Natural Gas	Base
Buck	CT12	186.8	172.8	Salisbury, N.C.	Natural Gas	Base
Buck	ST10	314.0	309.0	Salisbury, N.C.	Natural Gas	Base
Buck CTCC		688.0	654.7			
Dan River	CT8	177.8	159.9	Eden, N.C.	Natural Gas	Base
Dan River	CT9	176.4	161.6	Eden, N.C.	Natural Gas	Base
Dan River	ST7	317.7	316.2	Eden, N.C.	Natural Gas	Base
Dan River CTCC		671.9	637.7			
Total CTCC		1,359.9	1,292.4			

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

Hydro						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
99 Islands	1	2.4	2.4	Blacksburg, SC	Hydro	Peaking
99 Islands	2	2.4	2.4	Blacksburg, SC	Hydro	Peaking
99 Islands	3	2.4	2.4	Blacksburg, SC	Hydro	Peaking
99 Islands	4	2.4	2.4	Blacksburg, SC	Hydro	Peaking
99 Islands	5	0	0	Blacksburg, SC	Hydro	Peaking
99 Islands	6	0	0	Blacksburg, SC	Hydro	Peaking
Bear Creek	1	9.45	9.45	Tuckasegee, NC	Hydro	Peaking
Bridgewater	1	15	15	Morganton, NC	Hydro	Peaking
Bridgewater	2	15	15	Morganton, NC	Hydro	Peaking
Bridgewater	3	1.5	1.5	Morganton, NC	Hydro	Peaking
Bryson City	1	.48	.48	Whittier, NC	Hydro	Peaking
Bryson City	2	.48	.48	Whittier, NC	Hydro	Peaking
Cedar Cliff	1	6.4	6.4	Tuckasegee, NC	Hydro	Peaking
Cedar Cliff	2	0.4	0.4	Tuckasegee, NC	Hydro	Peaking
Cedar Creek	1	15	15	Great Falls, SC	Hydro	Peaking
Cedar Creek	2	15	15	Great Falls, SC	Hydro	Peaking
Cedar Creek	3	15	15	Great Falls, SC	Hydro	Peaking
Cowans Ford	1	81.3	81.3	Stanley, NC	Hydro	Peaking
Cowans Ford	2	81.3	81.3	Stanley, NC	Hydro	Peaking
Cowans Ford	3	81.3	81.3	Stanley, NC	Hydro	Peaking
Cowans Ford	4	81.3	81.3	Stanley, NC	Hydro	Peaking
Dearborn	1	14	14	Great Falls, SC	Hydro	Peaking
Dearborn	2	14	14	Great Falls, SC	Hydro	Peaking
Dearborn	3	14	14	Great Falls, SC	Hydro	Peaking
Fishing Creek	1	11	11	Great Falls, SC	Hydro	Peaking
Fishing Creek	2	9.5	9.5	Great Falls, SC	Hydro	Peaking
Fishing Creek	3	9.5	9.5	Great Falls, SC	Hydro	Peaking
Fishing Creek	4	11	11	Great Falls, SC	Hydro	Peaking
Fishing Creek	5	8	8	Great Falls, SC	Hydro	Peaking
Franklin	1	0.5	0.5	Franklin, NC	Hydro	Peaking
Franklin	2	0.5	0.5	Franklin, NC	Hydro	Peaking
Gaston Shoals	3	0	0	Blacksburg, SC	Hydro	Peaking
Gaston Shoals	4	1	1	Blacksburg, SC	Hydro	Peaking
Gaston Shoals	5	1	1	Blacksburg, SC	Hydro	Peaking
Gaston Shoals	6	1.7	1.7	Blacksburg, SC	Hydro	Peaking

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

Hydro cont.						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Rocky Creek	5	0	0	Great Falls, SC	Hydro	Peaking
Rocky Creek	6	0	0	Great Falls, SC	Hydro	Peaking
Rocky Creek	7	0	0	Great Falls, SC	Hydro	Peaking
Rocky Creek	8	0	0	Great Falls, SC	Hydro	Peaking
Tuxedo	1	3.2	3.2	Flat Rock, NC	Hydro	Peaking
Tuxedo	2	3.2	3.2	Flat Rock, NC	Hydro	Peaking
Tennessee Creek	1	9.8	9.8	Tuckasegee, NC	Hydro	Peaking
Thorpe	1	19.7	19.7	Tuckasegee, NC	Hydro	Peaking
Tuckasegee	1	2.5	2.5	Tuckasegee, NC	Hydro	Peaking
Wateree	1	17	17	Ridgeway, SC	Hydro	Peaking
Wateree	2	17	17	Ridgeway, SC	Hydro	Peaking
Wateree	3	17	17	Ridgeway, SC	Hydro	Peaking
Wateree	4	17	17	Ridgeway, SC	Hydro	Peaking
Wateree	5	17	17	Ridgeway, SC	Hydro	Peaking
Wylie	1	18	18	Fort Mill, SC	Hydro	Peaking
Wylie	2	18	18	Fort Mill, SC	Hydro	Peaking
Wylie	3	18	18	Fort Mill, SC	Hydro	Peaking
Wylie	4	18	18	Fort Mill, SC	Hydro	Peaking
Total NC		629.9	629.9			
Total SC		470.3	470.3			
Total Hydro		1,100.2	1,100.2			

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

Nuclear						
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
McGuire	1	1160.1	1138.5	Huntersville, NC	Nuclear	Base
McGuire	2	1187.2	1157.6	Huntersville, NC	Nuclear	Base
Catawba	1	1173.7	1140.1	York, SC	Nuclear	Base
Catawba	2	1179.8	1150.1	York, SC	Nuclear	Base
Oconee	1	865	847	Seneca, SC	Nuclear	Base
Oconee	2	872	848	Seneca, SC	Nuclear	Base
Oconee	3	881	859	Seneca, SC	Nuclear	Base
Total NC		2,347.3	2,296.1			
Total SC		4,971.5	4,844.2			
Total Nuclear		7,318.8	7,140.3			

Total Generation Capability		
	Winter Capacity (MW)	Summer Capacity (MW)
TOTAL DEC SYSTEM - NC	13,361	13,134
TOTAL DEC SYSTEM - SC	8,571	8,300
TOTAL DEC SYSTEM	22,202	21,434

Note (a): Unit information is provided by State, but resources are dispatched on a system-wide basis.
Note (b): Summer and winter capability does not take into account reductions due to future environmental emission controls.
Note (c): Catawba Units 1 and 2 capacity reflects 100% of the station’s capability, and does not factor in the North Carolina Municipal Power Agency #1’s (NCMPA#1) decision to sell or utilize its 832 MW retained ownership in Catawba.
Note (d): The Catawba units’ multiple owners and their effective ownership percentages are:

Catawba Owner	Percent Of Ownership
Duke Energy Carolinas	19.25%
North Carolina Electric Membership Corporation (NCEMC)	30.75%
NCMPA#1	37.5%
PMPA	12.5%

Planned Uprates			
Unit	**Date**	**Winter MW**	**Summer MW**
McGuire 1 [a,b]	Oct 2014	20	20
Catawba 1 [a,b]	Oct 2015	20	20
Oconee 1 [b]	Nov 2016	15	15
Oconee 2 [b]	Nov 2016	15	15
Oconee 3 [b]	Nov 2016	15	15
Dan River CC [b]	Mar 2015	24	24
Buck CC [b]	Feb 2015	14	14

Note a: The capacity represented in this table is the total operating capacity addition and is not adjusted for the Joint Exchange Agreement for Catawba and McGuire. The adjusted values are utilized in the resource plan.

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

Retirements				
Unit & Plant Name	**Location**	**Capacity (MW) Summer**	**Fuel Type**	**Retirement Date**
Buck 3[a]	Salisbury, NC	75	Coal	05/15/11
Buck 4[a]	Salisbury, NC	38	Coal	05/15/11
Cliffside 1[a]	Cliffside, NC	38	Coal	10/1/11
Cliffside 2[a]	Cliffside, NC	38	Coal	10/1/11
Cliffside 3[a]	Cliffside, NC	61	Coal	10/1/11
Cliffside 4[a]	Cliffside, NC	61	Coal	10/1/11
Dan River 1[a]	Eden, NC	67	Coal	04/1/12
Dan River 2[a]	Eden, NC	67	Coal	04/1/12
Dan River 3[a]	Eden, NC	142	Coal	04/1/12
Buzzard Roost 6C[b]	Chappels, SC	22	Combustion Turbine	10/1/12
Buzzard Roost 7C[b]	Chappels, SC	22	Combustion Turbine	10/1/12
Buzzard Roost 8C	Chappels, SC	22	Combustion Turbine	10/1/12
Buzzard Roost 9C[b]	Chappels, SC	22	Combustion Turbine	10/1/12
Buzzard Roost 10C[b]	Chappels, SC	18	Combustion Turbine	10/1/12
Buzzard Roost 11C[b]	Chappels, SC	18	Combustion Turbine	10/1/12
Buzzard Roost 12C[b]	Chappels, SC	18	Combustion Turbine	10/1/12
Buzzard Roost 13C[b]	Chappels, SC	18	Combustion Turbine	10/1/12
Buzzard Roost 14C[b]	Chappels, SC	18	Combustion Turbine	10/1/12
Buzzard Roost 15C[b]	Chappels, SC	18	Combustion Turbine	10/1/12
Riverbend 8C[b]	Mt. Holly, NC	0	Combustion Turbine	10/1/12
Riverbend 9C[b]	Mt. Holly, NC	22	Combustion Turbine	10/1/12
Riverbend 10C[b]	Mt. Holly, NC	22	Combustion Turbine	10/1/12
Riverbend 11C[b]	Mt. Holly, NC	20	Combustion Turbine	10/1/12
Buck 7C[b]	Spencer, NC	25	Combustion Turbine	10/1/12
Buck 8C[b]	Spencer, NC	25	Combustion Turbine	10/1/12
Buck 9C[b]	Spencer, NC	12	Combustion Turbine	10/1/12
Dan River 4C[b]	Eden, NC	0	Combustion Turbine	10/1/12
Dan River 5C[b]	Eden, N.C.	24	Combustion Turbine	10/1/12
Dan River 6C[b]	Eden, N.C.	24	Combustion Turbine	10/1/12
Riverbend 4[a]	Mt. Holly, NC	94	Coal	04/1/13
Riverbend 5[a]	Mt. Holly, NC	94	Coal	04/1/13
Riverbend 6[c]	Mt. Holly, NC	133	Coal	04/1/13
Riverbend 7[c]	Mt. Holly, NC	133	Coal	04/1/13
Buck 5[c]	Spencer, NC	128	Coal	04/1/13
Buck 6[c]	Spencer, NC	128	Coal	04/1/13
Lee 1[d]	Pelzer, SC	100	Coal	11/6/14
Lee 2[d]	Pelzer, SC	100	Coal	11/6/14
Lee 3[e]	Pelzer, SC	170	Coal	05/12/15
	Total	2,037 MW		

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 to 2012 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	Capacity (MW)	Fuel Type	Expected Retirement
Allen 1[a]	Belmont, NC	162	Coal	6/2028
Allen 2[a]	Belmont, NC	162	Coal	6/2028
Allen 3[a]	Belmont, NC	261	Coal	6/2028
Allen 4[a]	Belmont, NC	276	Coal	6/2028
Allen 5[a]	Belmont, NC	266	Coal	6/2028
Oconee 1[b, c]	Seneca, SC	862	Nuclear	5/2033
Oconee 2[b, c]	Seneca, SC	863	Nuclear	5/2033
Oconee 3[b, c]	Seneca, SC	874	Nuclear	5/2033
Total		3726		

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

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

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

Operating License Renewal:

Planned Operating License Renewal				
Plant & Unit Name	**Location**	**Original Operating License Expiration**	**Date of Approval**	**Extended Operating License Expiration**
Catawba Unit 1	York, SC	12/6/2024	12/5/2003	12/5/2043
Catawba Unit 2	York, SC	2/24/2026	12/5/2003	12/5/2043
McGuire Unit 1	Huntersville, NC	6/12/2021	12/5/2003	6/12/2041
McGuire Unit 2	Huntersville, NC	3/3/2023	12/5/2003	3/3/2043
Oconee Unit 1	Seneca, SC	2/6/2013	5/23/2000	2/6/2033
Oconee Unit 2	Seneca, SC	10/6/2013	5/23/2000	10/6/2033
Oconee Unit 3	Seneca, SC	7/19/2014	5/23/2000	7/19/2034
Bad Creek (PS)(1-4)	Salem, SC	N/A	8/1/1977	7//31/2027
Jocassee (PS) (1-4)	Salem, SC	N/A	9/1/1966	8/31/2016
Cowans Ford (1-4)	Stanley, NC	8/31/2008	Pending	8/31/2064 (Est)
Keowee (1&2)	Seneca, SC	N/A	9/1/1966	8/31/2016
Rhodhiss (1-3)	Rhodhiss, NC	8/31/2008	Pending	8/31/2064 (Est)
Bridge Water (1-3)	Morganton, NC	8/31/2008	Pending	8/31/2064 (Est)
Oxford (1&2)	Conover, NC	8/31/2008	Pending	8/31/2064 (Est)
Lookout Shoals (1-3)	Statesville, NC	8/31/2008	Pending	8/31/2064 (Est)
Mountain Island (1-4)	Mount Holly, NC	8/31/2008	Pending	8/31/2064 (Est)
Wylie (1-4)	Fort Mill, SC	8/31/2008	Pending	8/31/2064 (Est)
Fishing Creek (1-5)	Great Falls, SC	8/31/2008	Pending	8/31/2064 (Est)
Great Falls (1-8)	Great Falls, SC	8/31/2008	Pending	8/31/2064 (Est)
Dearborn (1-3)	Great Falls, SC	8/31/2008	Pending	8/31/2064 (Est)
Rocky Creek (1-8)	Great Falls, SC	8/31/2008	Pending	8/31/2064 (Est)
Cedar Creek (1-3)	Great Falls, SC	8/31/2008	Pending	8/31/2064 (Est)
Wateree (1-5)	Ridgeway, SC	8/31/2008	Pending	8/31/2064 (Est)
Gaston Shoals (3-6)	Blacksburg, SC	12/31/1993	6/1/1996	5/31/2036
Tuxedo (1&2)	Flat Rock, NC	N/A	N/A	N/A
Ninety Nine (1-6)	Blacksburg, SC	12/31/1993	6/1/1996	5/31/2036
Cedar Cliff (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Bear Creek (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Tennessee Creek (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Nantahala (1)	Topton, NC	2/28/2006	2/1/2012	1/31/2042

Planned Operating License Renewal cont.				
Plant & Unit Name	**Location**	**Original Operating License Expiration**	**Date of Approval**	**Extended Operating License Expiration**
Queens Creek (1)	Topton, NC	9/30/2001	3/1/2002	2/29/2032
Thorpe (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Tuckasegee (1)	Tuckasegee, NC	1/31/2006	5/1/2011	4/30/2041
Bryson City (1&2)	Whittier, NC	7/31/2005	7/1/2011	6/30/2041
Franklin (1&2)	Franklin, NC	7/31/2005	9/1/2011	8/31/2041
Mission (1-3)	Murphy, NC	7/31/2005	10/1/2011	9/30/2041

10. 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 2015 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 planning reserve margin. Over the 15-year planning horizon, DEC expects to require 5,711 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 2015 IRP focuses on the following:

- Complete construction of the Lee CC plant in Anderson, SC scheduled for operation in November of 2017.
- Continue the work necessary to obtain COLs for Lee Nuclear.
- Complete the resource adequacy study currently underway with Astrape Consulting.
- Procure CHP resources as cost-effective and diverse generation sources as appropriate.
- Continue to meet SC DERP and NC REPS compliance plans by adding additional renewable resources and EE to the DEC system.
- Continue to grow DSM in the Carolinas region.

Long-Term:

Beyond the next 5 years, DEC's 2015 IRP focuses on the following:

- Continue to seek the most cost-effective, reliable resources to meet the growing customer demand in the service territory. Currently, those are new combined cycle units and nuclear units in the 15 year planning horizon.
- Procure CHP resources as cost-effective and diverse generation sources as appropriate.
- Continue to meet SC DERP and NC REPS compliance plans by investing in additional renewable resources and EE on the DEC system.
- Continue to invest in DSM in the Carolinas region.

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 and EE and DSM.

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 2015 Load Forecast. This information is **CONFIDENTIAL**.

Wholesale Purchase Contracts

This table includes all wholesale purchase contracts that are included as resources in the 2015 IRP. This information is **CONFIDENTIAL**.

Table 11-A Wholesale Sales Contracts (CONFIDENTIAL)

[redacted]

Table 11-B Firm Wholesale Purchased Power Contracts (CONFIDENTIAL)

[redacted]

[redacted]