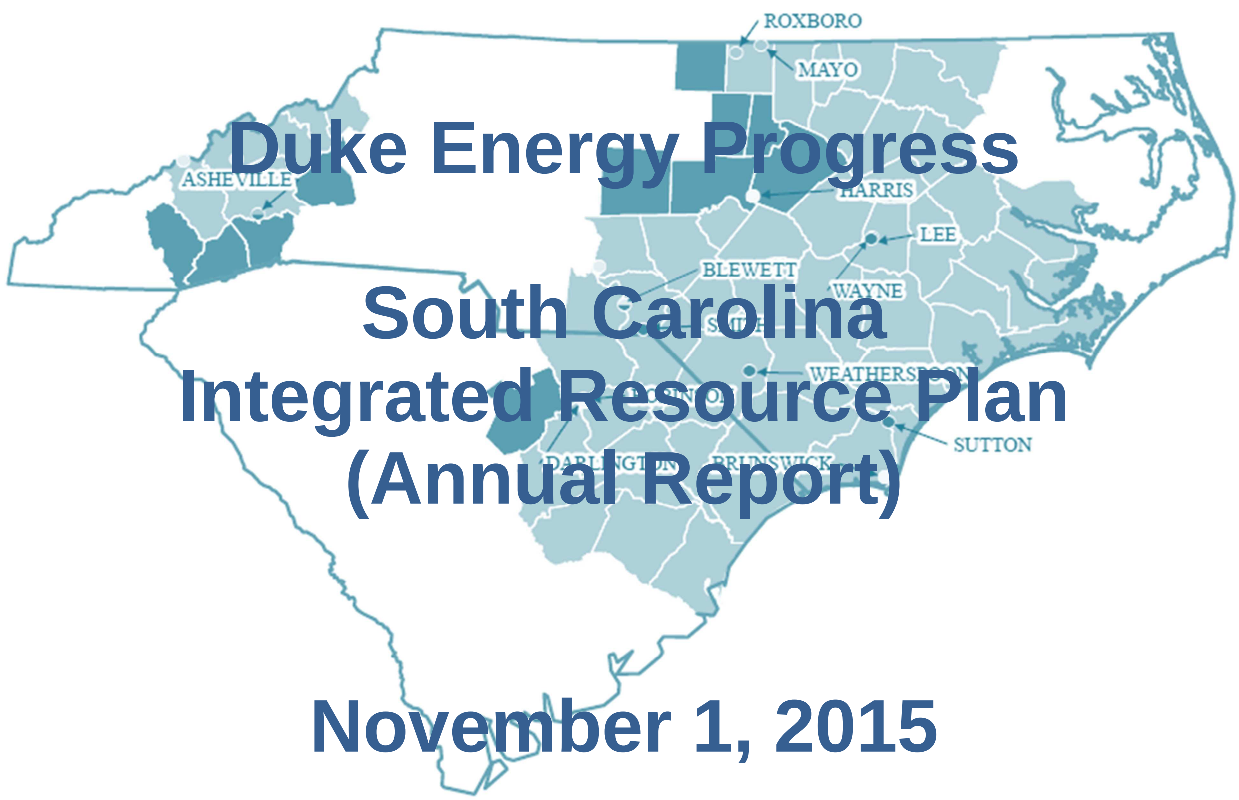

Duke Energy Progress

South Carolina
Integrated Resource Plan
(Annual Report)

November 1, 2015

PUBLIC

DEP SC 2015 IRP
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1. INTRODUCTION

For more than a century, Duke Energy Progress (DEP) has provided affordable and reliable electricity to customers in South Carolina (SC) and North Carolina (NC) now totaling more than 1.5 million in number. The Company continues to serve its customers by planning for future demand requirements in the most reliable and economic way possible.

Historically, each year, as required by the Public Service Commission of South Carolina (PSCSC) and the North Carolina Utilities Commission (NCUC), DEP submits a long-range planning document called the Integrated Resource Plan (IRP) 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.

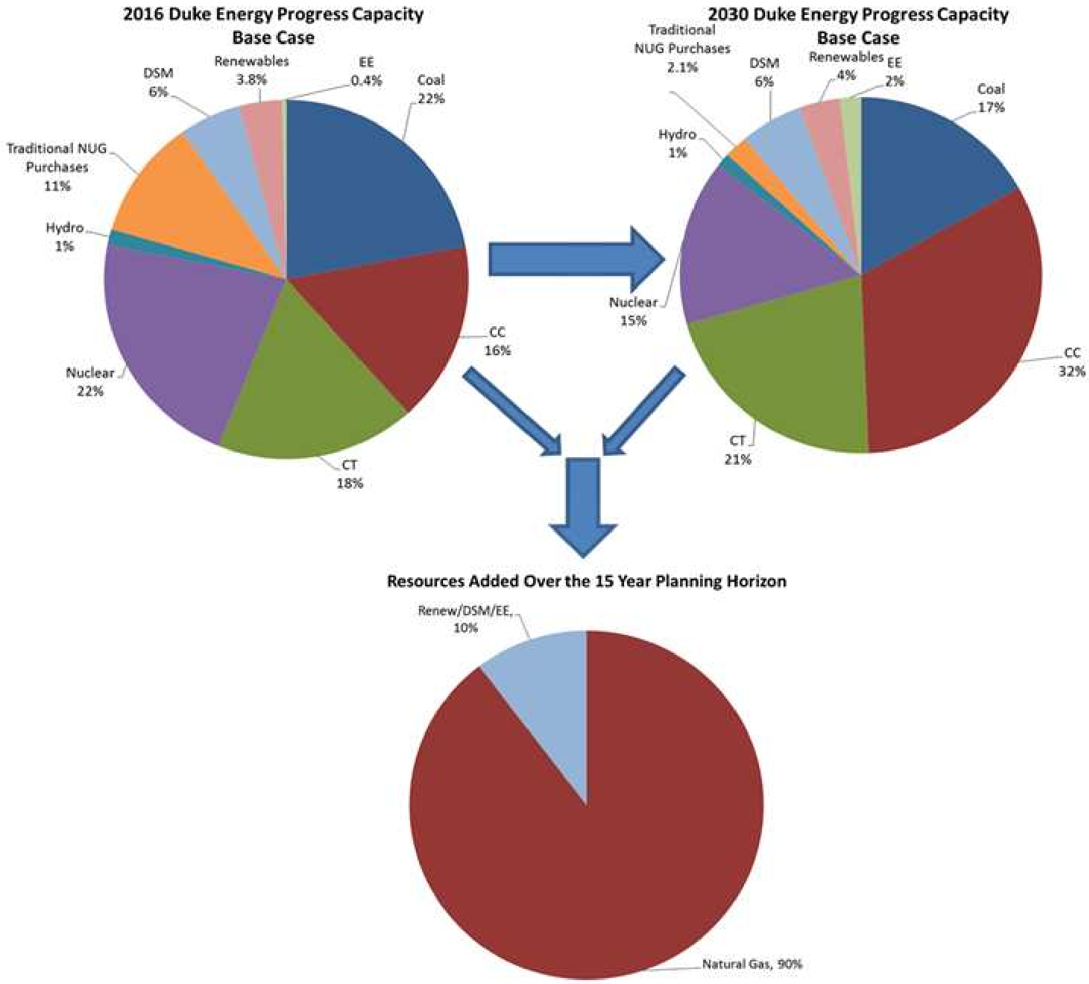
The Company files separate 2015 IRPs for South Carolina and North Carolina. However, the IRP analyzes the system as one DEP utility across both states including customer demand, energy efficiency (EE), demand side management (DSM), renewable resources and traditional supply-side resources. As such, the quantitative analysis contained in both the South Carolina and North Carolina filings is identical, while certain sections dealing with state-specific issues such as state renewable standards or environmental standards may be specific to that state's IRP.

2. 2015 IRP SUMMARY

As 2015 is an update year for the IRP, DEP 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 2015 IRP Base Case, projected incremental needs are driven by load growth and the retirement of aging combustion turbine (CT) and 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 maintain a diversified resource mix while reducing the environmental footprint associated with each unit of energy production.

3. IRP PROCESS OVERVIEW

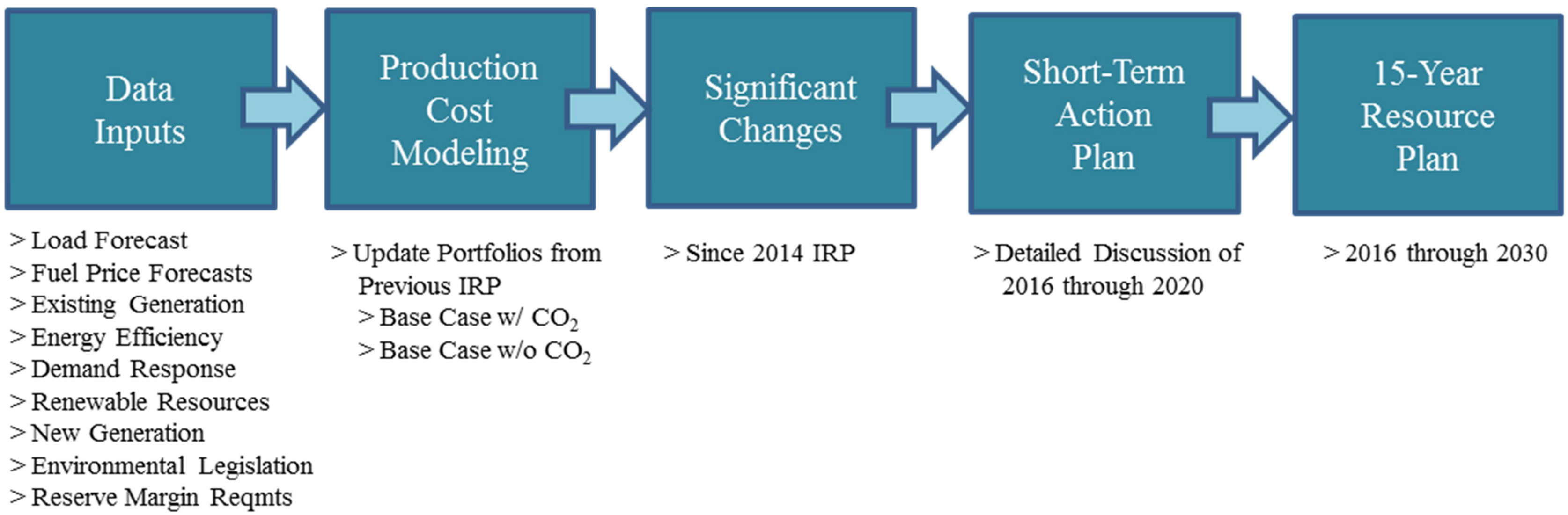
To meet the future needs of DEP's customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, the Company develops a load forecast of cumulative energy sales and hourly peak demand. To determine total resources needed, the 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 DEP considers the non-firm energy purchases and sales associated with the Joint Dispatch Agreement (JDA) with Duke Energy Carolinas (DEC) in the development of its independent Base Case. To accomplish this, DEP and DEC 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 that 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 (odd years) of the IRP cycle.

Figure 3-A Simplified IRP Process



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 DEP Spring Load Forecast is updated to include the most current data available at this time. 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 DEP 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 DEP 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 DEP 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%	1.3%	1.2%	1.6%	1.5%	1.3%
Includes impact of new EE programs	1.3%	1.2%	1.2%	1.4%	1.3%	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 Progress 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 DEP 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 DEP system.

As mentioned above, DEP 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 DEP QF Interconnection Queue

Utility	Facility State	Energy Source Type	Number of Pending Projects	Pending Capacity MW AC
DEP	**NC**	Biogas	2	7
		Biomass	3	53
		Landfill Gas	2	16
		Other	2	1
		Solar	436	3244
		Wood Waste	1	5
DEP	**NC Total**		**446**	**3326**
	SC	Solar	37	605
	SC Total		**37**	**605**
DEP Total			**483**	**3931**

c) <u>Addition of Combined Heat & Power (CHP) to the IRP</u>

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 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:

2019: 20 MW
2021: 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) Reserve Margin:

In 2012, DEP and DEC 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 DEP and DEC had adopted a 14.5% minimum summer planning reserve margin for scheduling new resource additions.

In 2015, DEP and DEC 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, DEP 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

DEP's resource plan reflects reserve margins ranging from 17.0% to 21.9%. Reserves projected in DEP's IRP meet the minimum planning reserve margin target and thus satisfy the one day in 10 years LOLE criterion. The projected reserve margin exceeds the minimum 17% target by 3% or more in 2016-2018 primarily due to a decrease in the load forecast compared to earlier projections. The projected reserve margin exceeds the target by 3% or more in 2022 as a result of the economic addition of a large combined-cycle facility. A significant increase in projected solar capacity causes reserves to exceed 3% of the target in 2023. The projected reserve margin also exceeds the target by 3% or more in 2027 as a result of the economic addition of a large block of combustion turbine capacity.

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 DEP's IRP are appropriate for providing an economic and reliable power supply.

e) Fuel Costs

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 models, on the other hand, represent a projection of fuel prices into the future taking into account changing supply and demand assumptions of the changing dynamics 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, DEP and DEC 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) New Resource Retirements/Additions

Asheville Plant

Note as to section below: As announced on October 8, 2015, the Company is looking at all options that can meet the region's power demand over the next 10 to 15 years – including possible alternatives to the transmission line, Campobello substation and the configuration of the proposed Asheville natural gas power plant.

As part of the Western Carolinas Modernization Project (WCMP) announced in the spring of 2015, the combined 376 MW Asheville 1 & 2 coal units are planned to be retired no later than January 31, 2020. The retired units are expected to be replaced with a 663 MW natural gas combined cycle unit on site in November 2019, along with necessary and associated natural gas delivery and electric transmission infrastructure projects. Additionally, an undetermined amount of solar generation is planned for installation at the same site shortly after the retirement of the coal plants. The Certificate of Public Convenience and Necessity (CPCN) for the new combined cycle unit is expected to be filed with the NCUC in the fourth quarter of 2015. As part of the WCMP, the three fuel oil combustion turbine units totaling 126 MW that were planned for Asheville in 2019, as included in the 2014 DEP IRP Short-Term Action Plan, are no longer necessary and have been removed from the 2015 IRP.

This retirement date for the Asheville coal units represents an acceleration of approximately 10 years from previous planning assumptions. The retirements of the units, and the corresponding investments in the required infrastructure to replace those units, are being accelerated due to a culmination of several factors. These factors include continued declines in natural gas prices, the unique opportunity to take advantage of an economic gas delivery project by the local gas distribution company, and the opportunity to avoid significant investment in additional environmental controls at the coal units that would be required by 2020.

In summary, benefits from the WCMP include, but are not limited to:

- Significant fuel cost reductions through the construction of new transmission infrastructure and combined cycle plant coupled with eliminating the uneconomic utilization of the coal units.
- Avoidance of significant capital expenditures for further environmental controls on the coal units.
- Avoidance of costs associated with three fuel oil combustion turbine units that would be required in the absence of the WCMP.
- Engagement in a unique opportunity to partner with the local gas distribution company to bring cost-effective natural gas supply to the western Carolinas.
- Enhanced reliability following multiple polar vortex events.

Sutton and Lee Inlet Air Chillers

The 2014 IRP called for installation of 137 MW of inlet air chiller technology at Sutton and Lee combined cycle plants prior to the summer of 2018. The most recent analysis of summer reserves shows that these chillers can be delayed until at least the summer of 2019. The 2015 IRP shows installation in May 2019, and a slight downward adjustment of capacity to 135 MW (77 MW at Lee CC and 58 MW at Sutton CC). The benefits to winter capacity from these chillers is not included in the plan as the chiller technology only provides summer peaking capability.

Purchase of NCEMPA Portion of Assets

The North Carolina Eastern Municipal Power Agency (NCEMPA) previously owned partial interest in several Duke Energy Progress plants, including Brunswick Nuclear Plant Units 1 and 2, Mayo Plant, Roxboro Plant Unit 4 and the Harris Nuclear Plant. The Power Agency's ownership interest in these plants represented approximately 700 megawatts of generating capacity. DEP's prior IRPs included NCEMPA's ownership share of the jointly owned assets along with the associated load obligation.

Boards of directors of Duke Energy and the NCEMPA approved an agreement for Duke Energy Progress to purchase the Power Agency's ownership in these generating assets. All required regulatory approvals have been completed and the agreement closed on July 31, 2015. DEP is now 100% owner of these previously jointly owned assets. Under the agreement, Duke Energy Progress will continue meeting the needs of NCEMPA customers previously served by the Power Agency's interest in Duke Energy Progress' plants.

g) EPA Clean Power Plan (CPP):

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.

h) <u>Transmission Planned or Under Construction</u>

This section contains the planned transmission line and substation additions since the 2014 IRP. Only those projects added since the 2014 IRP are included. A discussion of the adequacy of DEP's transmission system is also included. Table 4-C lists the transmission projects that are planned to meet reliability needs.

Table 4-C: DEP Transmission Line and Substation Additions

	Location		Capacity	Voltage	
Year	**From**	**To**	**MVA**	**KV**	**Comments**
2016	Falls	-	336	230/115	New
2016	Selma	-	336	230/115	Upgrade
2018[2]	Vanderbilt	West Asheville	307	115	Upgrade
2018[3]	Richmond	Raeford	1195	230	Relocate, new
2018[4]	Ft. Bragg Woodruff St.	Raeford	1195	230	Relocate, new
2019	Craggy	Enka	799	230	New
2019	Asheville Plant	-	448	230/115	New
2020	Jacksonville	Grants Creek	1195	230	New
2020	Newport	Harlowe	681	230	New

DEP Transmission System Adequacy

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

[2] The date for this project in the 2014 IRP was 2016. The project has been re-scheduled for 2018.
[3] This project was included in the 2014 IRP, however some parameters have been made and are represented on the following pages.
[4] This project was included in the 2014 IRP, however some parameters have been made and are represented on the following pages.

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

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with DEP's Transmission Planning Summary guidelines for voltage and thermal loading. The annual screening uses methods that comply with SERC policy and NERC Reliability Standards and the screening results identify the need for future transmission system expansion and upgrades. The transmission system is planned to ensure that no equipment overloads and adequate voltage is maintained to provide reliable service. The most stressful scenario is typically at peak load with certain equipment out of service. A thorough screening process is used to analyze the impact of potential equipment failures or other disturbances. As problems are identified, solutions are developed and evaluated.

Transmission planning and requests for transmission service and generator interconnection are interrelated to the resource planning process. DEP currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Summary guidelines and the FERC Open Access Transmission Tariff (OATT). The Company performs studies to ensure transfer capability is acceptable to meet reliability needs and customers' expected use of the transmission system. Generator interconnection requests are studied in accordance with the Large and Small Generator Interconnection Procedures in the OATT and the North Carolina Interconnection Procedures.

Southeastern Reliability Corporation (SERC) audits DEP every three years for compliance with NERC Reliability Standards. Specifically, the audit requires DEP to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the Company's annual compliance filing certifications. SERC conducted a NERC Reliability Standards compliance audit of DEP in the fall of 2014. DEP received "No Findings" from the audit team.

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

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

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

- Ensure interconnected system compliance with NERC Reliability Standards.

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

Application of the practices and procedures described above have ensured DEP'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 Progress 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 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 Utility EE 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 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 0.9% 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 DEP service area.

Weather impacts are incorporated into the models by using Heating Degree Days and Cooling Degree Days with a base temperature of 65. The forecast of degree days is based on a 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 DEP'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 11-A in Chapter 11.

Historical Values

It should be noted that the long-term structural decline of the Textile industry and the recession of 2008-2009 have had an adverse impact on DEP sales. 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 DEP 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	1,123	1,149	1,174	1,195	1,207	1,216	1,221	1,231	1,242	1,257
Commercial	205	210	214	216	215	216	217	219	222	222
Industrial	4	4	4	4	5	5	4	4	4	4
Total	1,332	1,363	1,392	1,415	1,426	1,437	1,443	1,455	1,468	1,484

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

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Residential	16,003	16,664	16,259	17,200	17,000	17,117	19,108	17,764	16,663	18,201
Commercial	13,019	13,314	13,358	14,033	13,940	13,639	14,184	13,709	13,581	13,887
Industrial	13,036	12,741	12,416	11,883	11,216	10,375	10,677	10,573	10,508	10,321
Military &Other	1,431	1,410	1,419	1,438	1,467	1,497	1,574	1,591	1,602	1,614
Total Retail	43,490	44,129	43,451	44,553	43,622	42,628	45,544	43,637	42,355	44,023
Wholesale	12,439	12,210	12,231	12,656	12,868	12,772	12,772	12,267	12,676	13,578
Total System	55,928	56,340	55,682	57,209	56,489	55,400	58,316	55,903	55,031	57,601

Utility Energy Efficiency

A new process for reflecting the impacts of UEE on the forecast was introduced in Spring 2015. In the latest forecast, the concept of '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 DEP 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 DEP 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**
2016	**66,805,005**	**1,611,837**	**37,998**	**0**	**1,573,839**	**65,231,166**
2017	**67,539,168**	**1,789,279**	**104,966**	**0**	**1,684,313**	**65,854,855**
2018	**68,364,378**	**1,968,176**	**206,527**	**0**	**1,761,649**	**66,602,728**
2019	**69,176,185**	**2,144,881**	**351,978**	**0**	**1,792,903**	**67,383,282**
2020	**70,004,351**	**2,321,586**	**533,731**	**17,605**	**1,770,249**	**68,234,102**
2021	**70,639,854**	**2,498,291**	**733,010**	**65,593**	**1,699,688**	**68,940,166**
2022	**71,379,803**	**2,674,996**	**882,119**	**172,724**	**1,620,152**	**69,759,651**
2023	**72,151,810**	**2,851,701**	**999,141**	**298,876**	**1,553,685**	**70,598,125**
2024	**73,065,309**	**3,028,406**	**1,068,137**	**438,547**	**1,521,722**	**71,543,587**
2025	**73,863,360**	**3,205,111**	**1,098,140**	**595,656**	**1,511,315**	**72,352,045**
2026	**74,748,903**	**3,381,816**	**1,106,441**	**765,119**	**1,510,256**	**73,238,647**
2027	**75,636,152**	**3,558,521**	**1,106,441**	**948,224**	**1,503,856**	**74,132,296**
2028	**76,674,488**	**3,735,226**	**1,106,441**	**1,139,861**	**1,488,924**	**75,185,564**
2029	**77,495,104**	**3,911,931**	**1,106,441**	**1,338,884**	**1,466,606**	**76,028,497**
2030	**78,426,888**	**4,088,636**	**1,106,441**	**1,540,020**	**1,442,175**	**76,984,713**
Note: UEE Data is net of free riders						

Results

Tabulations of class forecasts 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	1,292	225	4	1	1,523
2017	1,309	227	4	2	1,542
2018	1,325	229	4	2	1,560
2019	1,342	231	4	2	1,578
2020	1,358	233	4	2	1,596
2021	1,373	235	4	2	1,614
2022	1,389	237	4	2	1,632
2023	1,404	239	5	2	1,649
2024	1,419	241	5	2	1,667
2025	1,434	244	5	2	1,683
2026	1,448	246	5	2	1,700
2027	1,463	248	5	2	1,717
2028	1,478	250	5	2	1,734
2029	1,492	252	5	2	1,751
2030	1,507	255	5	2	1,767

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

	Residential Gwh	Commercial Gwh	Industrial Gwh	Other Gwh	Retail Gwh
2016	17,967	14,043	10,412	1,620	44,042
2017	18,166	14,207	10,497	1,618	44,487
2018	18,383	14,418	10,574	1,615	44,990
2019	18,620	14,635	10,658	1,612	45,525
2020	18,878	14,863	10,758	1,610	46,107
2021	19,095	15,048	10,836	1,607	46,587
2022	19,354	15,252	10,920	1,605	47,130
2023	19,615	15,476	11,020	1,602	47,713
2024	19,897	15,734	11,120	1,600	48,351
2025	20,125	15,952	11,219	1,597	48,894
2026	20,402	16,201	11,316	1,595	49,514
2027	20,681	16,460	11,416	1,593	50,150
2028	21,042	16,756	11,514	1,591	50,904
2029	21,304	17,008	11,611	1,589	51,511
2030	21,616	17,311	11,723	1,587	52,236

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 Progress 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%	1.3%	1.2%
Includes impact of new EE programs	1.3%	1.2%	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 meter.

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

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2016	13,048	12,767	66,805
2017	13,224	12,938	67,539
2018	13,402	13,133	68,364
2019	13,595	13,342	69,176
2020	13,949	13,531	70,004
2021	14,208	13,703	70,640
2022	14,444	13,882	71,380
2023	14,709	14,062	72,152
2024	14,901	14,278	73,065
2025	15,082	14,437	73,863
2026	15,264	14,621	74,749
2027	15,440	14,797	75,636
2028	15,636	15,022	76,674
2029	15,814	15,183	77,495
2030	15,981	15,352	78,427

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

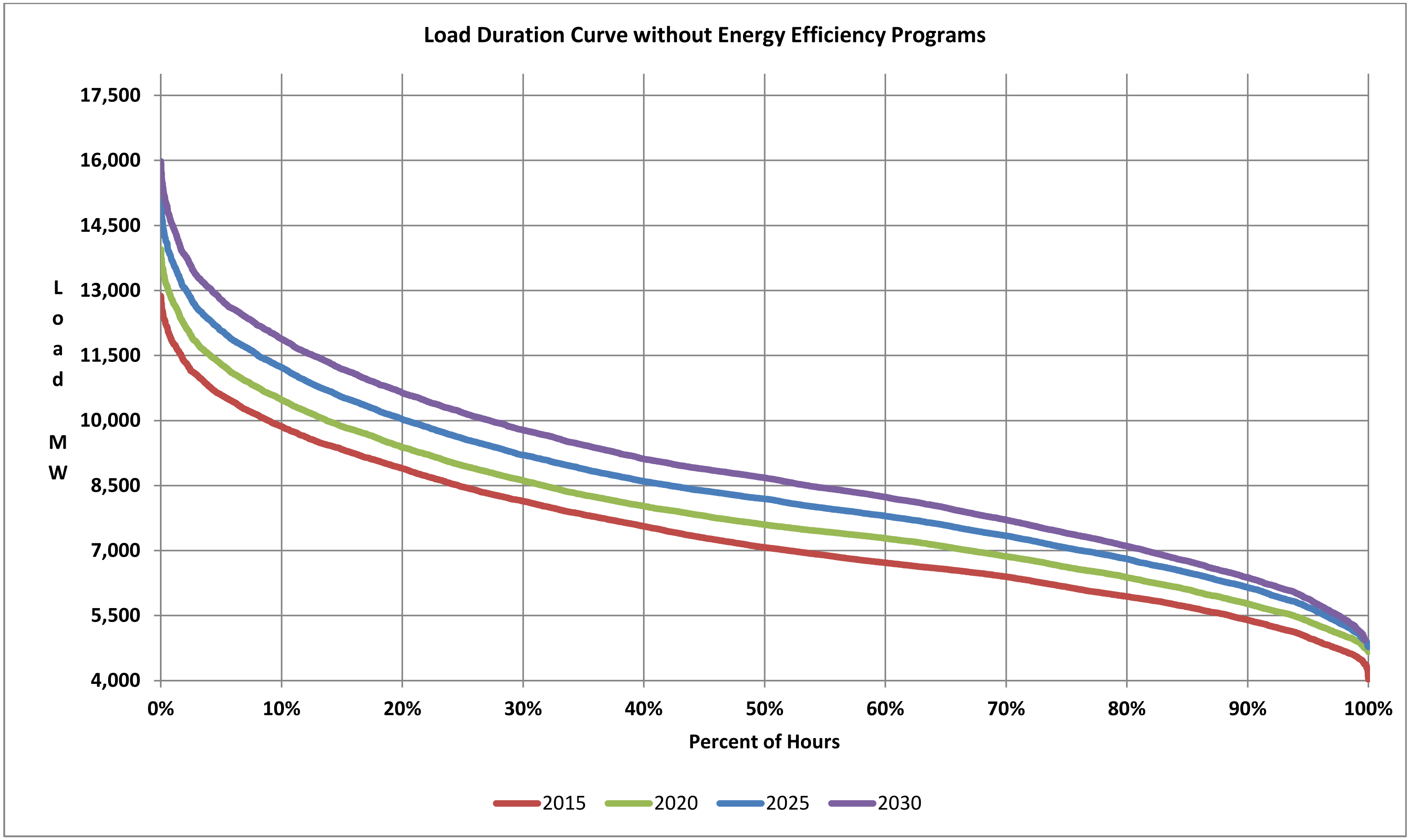
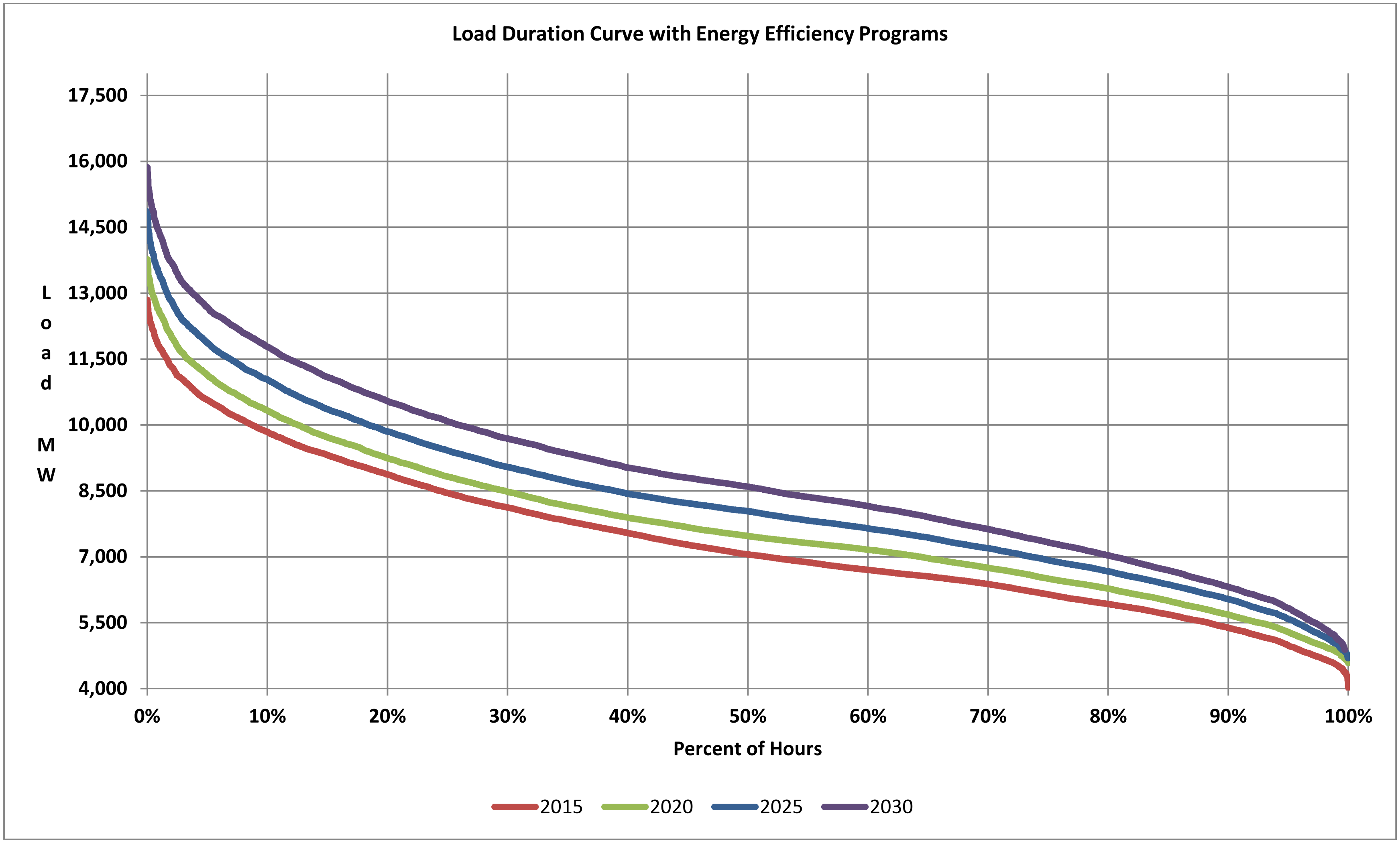


Table 5-H Load Forecast with Energy Efficiency Programs & Before Demand Reduction Programs

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2016	12,981	12,727	65,231
2017	13,127	12,877	65,855
2018	13,277	13,050	66,603
2019	13,440	13,236	67,383
2020	13,766	13,403	68,234
2021	13,996	13,552	68,940
2022	14,205	13,711	69,760
2023	14,445	13,872	70,598
2024	14,611	14,070	71,544
2025	14,770	14,211	72,352
2026	14,934	14,381	73,239
2027	15,098	14,548	74,132
2028	15,292	14,772	75,186
2029	15,465	14,930	76,028
2030	15,629	15,096	76,985

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



6. ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT:

Demand Side Management and Energy Efficiency Programs

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

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

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

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

DSM/EE Program Descriptions

Residential Home Energy Improvement Program
Program Type: Energy Efficiency

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

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

Residential Home Energy Improvement Program			
As of:	**Participants**	**Gross MWh Energy Savings**	**Gross Peak kW Demand Savings**
December 31, 20143	105,910	35,057	32,806

Residential New Construction Program
Program Type: Energy Efficiency

The Residential New Construction Program offers single family builders and multi-family developers equipment incentives for installing high efficiency HVAC and/or heat pump water heating equipment in new residential construction; or whole house incentives for meeting or exceeding the 2012 North Carolina Energy Conservation Code High Efficiency Residential Option ("HERO").

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

Residential New Construction Program			
As of:	**Participants**	**Gross MWh Energy Savings**	**Gross Peak kW Demand Savings**
December 31, 2014	10,799	16,710	5,940

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

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

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

Residential Neighborhood Energy Saver Program			
As of:	**Participants**	**Gross MWh Energy Savings**	**Gross Peak kW Demand Savings**
December 31, 2014	23,407	11,670	1,543

Energy Efficient Lighting Program
Program Type: Energy Efficiency

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

Energy Efficient Lighting Program			
As of:	**Bulbs Sold**	**Gross MWh Energy Savings**	**Gross Peak kW Demand Savings**
December 31, 2014	20,098,449	1,041,241	152,950

Residential Appliance Recycling Program
Program Type: Energy Efficiency

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

Residential Appliance Recycling Program			
As of:	**Participants**	**Gross MWh Energy Savings**	**Gross Peak kW Demand Savings**
December 31, 2014	38,944	40,270	4,597

Residential My Home Energy Report Program
Program Type: Energy Efficiency

The My Home Energy Report (MyHER) Program was designed to help customers better understand their energy usage. The report informs customers about their energy use with simple and easy to understood graphics. The report also compares customers' energy use with similar homes in their area based on home size, age and heating source and motivates customers to change behavior and reduce their energy use by presenting them with timely tips and program offers. Customers receive up to eight paper reports a year. My Home Energy Interactive is a website that complements the report.

MyHER received regulatory approval during the second half of 2014 and eligible customers received their first report during the first quarter of 2015. It replaces the Residential Energy Efficient Benchmarking Program, which ended in 2014 with the last report sent out in June. The table below provides a final summary of results for the Residential Energy Efficiency Benchmarking Program.

Residential Energy Efficient Benchmarking Program			
As of:	**Participants**	**Gross MWh Energy Savings**	**Gross Peak kW Demand Savings**
December 31, 2014	42,928	15,403	2,683

Energy Efficiency Education Program
Program Type: Energy Efficiency

The Energy Efficiency Education Program is an energy efficiency program available to students in grades K-12 enrolled in public and private schools who reside in households served by Duke Energy Progress. The Program provides an important message about energy efficiency through a live theatrical production performed by two professional actors. Teachers receive supportive educational material for classroom and student take home assignments, such as school posters, teacher guides, and classroom and family activity books. The current curriculum is administered by The National Theatre for Children and targets grade K-8 students.

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

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

Multi-Family Energy Efficiency Program
Program Type: Energy Efficiency

The Multi-family Energy Efficiency Program was approved in 2014 and allows DEP to target energy efficiency measures specifically for multi-family apartment complexes. The Program is designed to help property managers upgrade lighting with energy efficient CFLs and also save energy by offering water measures such as bath and kitchen faucet aerators, water saving showerheads and pipe wrap. The Program also offers properties the option of direct install service by a third-party vendor or to use their own property maintenance crews to complete the installations. Post- installation Quality Assurance inspections by an independent third-party are conducted on 20 percent of properties that completed installations in a given month.

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

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

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

- HVAC
- Lighting
- Refrigeration

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

The program also seeks to meet the following overall goals:

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

CIG Energy Efficiency Program			
As of:	**Participants**	**Gross MWh Energy Savings**	**Gross Peak kW Demand Savings**
December 31, 2014	5,306	287,126	65,319

Small Business Energy Saver Program
Program Type: Energy Efficiency

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

Small Business Energy Saver Program			
As of:	**Participants**	**Gross MWh Energy Savings**	**Gross Peak kW Demand Savings**
December 31, 2014	3,708	50,659	13,489

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

The DSDR program is an application of Smart Grid technology that provides the capability to reduce peak demand for four to six hours at a time, which is the duration consistent with typical peak load periods, while also maintaining customer delivery voltage above the minimum requirement when the program is in use. The increased peak load reduction capability and flexibility associated with DSDR will result in the displacement of the need for additional peaking generation capacity. This capability is accomplished by investing in a robust system of advanced technology, telecommunications, equipment, and operating controls. The DSDR Program helps DEP implement a least cost mix of demand reduction and generation measures that meet the electricity needs of its customers. With the full implementation of DSDR in June 2014, all of DEP's voltage control capability now falls under the DSDR program.

Distribution System Demand Response Program			
As of:	**Participants**	**MWh Energy Savings**	**Summer MW Capability**
December 31, 2014	NA	40,774	322

Since DEP's last biennial resource plan was filed on September 2, 2014, there have been 35 voltage control activations through June 24, 2015. The following table shows the date, starting and ending time, and duration for all voltage control activations since July 2014.

Voltage Control			
Date	**Start Time**	**End Time**	**Duration (H:MM)**
7/2/2014	15:00	18:00	3:00

Voltage Control			
Date	**Start Time**	**End Time**	**Duration (H:MM)**
7/9/2014	15:00	16:03	1:03
7/14/2014	15:00	18:00	3:00
7/16/2014	10:00	11:00	1:00
7/23/2014	15:00	18:00	3:00
7/28/2014	15:00	17:30	2:30
8/6/2014	15:00	18:00	3:00
8/12/2014	16:08	16:25	0:17
8/20/2014	15:00	18:00	3:00
8/21/2014	15:00	18:00	3:00
8/22/2014	15:00	17:00	2:00
9/17/2014	13:00	14:00	1:00
11/17/2014	10:00	11:00	1:00
11/19/2014	6:30	9:00	2:30
11/22/2014	17:13	17:29	0:16
12/8/2014	8:06	8:40	0:34
12/12/2014	7:58	8:30	0:32
12/16/2014	8:00	8:30	0:30
1/7/2015	7:00	8:00	1:00
1/8/2015	6:00	9:00	3:00
1/9/2015	7:00	8:00	1:00
1/23/2015	8:21	8:37	0:16
1/28/2015	6:30	8:30	2:00
1/29/2015	6:30	8:30	2:00
2/3/2015	6:30	8:30	2:00
2/6/2015	6:30	8:30	2:00
2/13/2015	6:30	8:30	2:00
2/15/2015	19:00	22:00	3:00
2/16/2015	6:30	9:30	3:00
2/19/2015	6:30	9:30	3:00
2/19/2015	19:00	22:00	3:00
2/20/2015	6:30	7:00	0:30
2/20/2015	7:00	8:30	1:30
2/20/2015	8:30	9:30	1:00
2/20/2015	19:00	22:00	3:00
4/9/2015	17:35	18:11	0:36

Voltage Control			
Date	**Start Time**	**End Time**	**Duration (H:MM)**
4/29/2015	12:30	13:00	0:30
5/19/2015	12:00	13:00	1:00
5/26/2015	11:00	12:00	1:00
6/15/2015	16:00	19:33	3:33
6/16/2015	16:00	19:27	3:27
6/18/2015	15:00	16:52	1:52
6/22/2015	15:00	18:30	3:30
6/23/2015	16:03	16:17	0:14
6/24/2015	12:00	13:35	1:35
6/24/2015	15:00	19:05	4:05

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

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

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

For each of the control options above, an annual bill credit is provided to program participants in exchange for allowing DEP to control the listed appliances. The program provides DEP with the ability to reduce and shift peak loads, thereby enabling a corresponding deferral of new supply-side peaking generation and enhancing system reliability. Participating customers are impacted by (1) the installation of load control equipment at their residence, (2) load control events which curtail the operation of their air conditioning, heat pump strip heating or water heating unit for a period of time each hour, and (3) the receipt of an annual bill credit from DEP in exchange for allowing DEP to control their electric equipment.

Residential EnergyWise Home Statistics			
As of:	**Participants**	**Summer MW Capability**	**Winter MW Capability**
December 31, 2014	121,027	251	9.8

The following table shows Residential EnergyWise Home^{SM} Program activations that were not for testing purposes from July 1, 2014 through June 30, 2015.

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

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

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

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

In response to EPA regulations finalized January 2013, a new Emergency Generator Option was implemented effective January 1, 2014, to allow customers with emergency generators to continue participation in demand response programs. To comply with the new rule, dispatch of the Emergency Generator Option must be limited to NERC Level II (EEA2) except for an annual readiness test. 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 DEP 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. The original DRA program design, now referred to as the Curtailable Option, continues to be dispatched as it has historically without NERC Level restrictions.

CIG Demand Response Automation Statistics			
As of:	**Premises**	**Peak Capability (MW)**	
		Summer	**Winter**
December 31, 2014	52	22.3	15.6

The table below shows information for each CIG Demand Response Automation Program non-test control event from July 1, 2014 through June 30, 2015.

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

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

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

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

Previously Existing Demand Side Management and Energy Efficiency Programs

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

Energy Efficient Home Program
Program Type: Energy Efficiency

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

Curtailable Rates
Program Type: Demand Response

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

Curtailable Rate Activations			
Date	**Start/End Time**	**Duration (Minutes)**	**MW Load Reduction***
1/7/2014	06:30-11:00	270	211
1/8/2014	06:00-10:00	240	243
1/8/2015	06:00-10:00	240	240
2/20/2015	06:00-10:00	240	240

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

Time-of-Use Rates
Program Type: Demand Response

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

Thermal Energy Storage Rates
Program Type: Demand Response

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

Real-Time Pricing
Program Type: Demand Response

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

Summary of Available Existing Demand-Side and Energy Efficiency Programs

The following table provides current information available at the time of this report on DEP's pre-Senate Bill 3 DSM/EE programs (i.e., those programs that were in effect prior to January 1, 2008). This information, where applicable, includes program type, capacity, energy, and number of customers enrolled in the program as of the end of 2014, as well as load control activations since those enumerated in DEP's last biennial resource plan. The energy savings impacts of these existing programs are embedded within DEP's load and energy forecasts.

Program Description	Type	Capacity (MW)	Annual Energy (MWH)	Participants	Activations Since Last Biennial Report
Energy Efficiency Programs[5]	EE	473	NA	NA	NA
Real Time Pricing (RTP)	DSM	55	NA	105	NA
Commercial & Industrial TOU	DSM	6.4	NA	31,759	NA
Residential TOU	DSM	11.6	NA	29,942	NA
Curtailable Rates	DSM	278	NA	77	4

Summary of Prospective Program Opportunities

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

- Business Energy Report Pilot Program – Planning to introduce the non-residential Business Energy Report Pilot Program ("Pilot"). The purpose of the Pilot is to achieve energy savings by providing participants with periodic usage reports and give increased

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

insights into their own energy use. The information in the report is designed to motivate participants to adopt targeted energy efficient tips that will lead to more energy efficient practices and behaviors, thus creating energy savings. These savings would not be realized without the Pilot.

- EnergyWise for Business – DEP recently filed for approval of a new joint energy efficiency and demand response program targeted toward the small business market segment.
- Single-Family Water Measures – DEP recently filed for approval of this new program designed to provide residential single-family customers with measures to reduce water usage and water heating energy consumption. Participants will receive a free kit mailed to their home containing: (1) Low Flow Showerheads; (2) Kitchen Aerator; (3) Bathroom Aerators; and (4) Pipe Wrap Insulated Tape.
- HVAC Energy Efficiency – This recently filed program represents an enhancement to the currently existing Home Energy Improvement program by expanding the number of HVAC measure options and introducing several new measures (such as smart thermostats and quality installation).
- Home Energy House Call – Investigating the potential for expanding DEC's Home Energy House Call Program to the DEP service area.
- Low Income Weatherization – DEP plans to investigate the potential for a new program that would offer weatherization services to low income customers.

EE and DSM Program Screening

The Company evaluates the costs and benefits of DSM and EE programs and measures by using the same data for both generation planning and DSM/EE program planning to ensure that demand-side resources are compared to supply side resources on a level playing field.

The analysis of energy efficiency and demand side management cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: Utility Cost Test (UCT), Rate Impact Measure (RIM) Test, Total Resource Cost (TRC) Test, and Participant Test (PCT).

- The UCT compares utility benefits (avoided costs) to the costs incurred by the utility to implement the program, and does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs, and load (line) losses.

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

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

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

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

Forecast Methodology

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

In order to better align the IRP process between DEC and DEP, the DEP EE Forecast methodology was changed this year to match the same process as that used by DEC.

As part of its annual planning process, DEP created a detailed Base Case forecast of its EE and DSM portfolio for the upcoming 5 year planning horizon. In addition, DEP also developed a long run electric load forecast 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 DEP 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[6].

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 1,065 GWh achieved since 2011, the projected EE achievement reaches this level by the year 2034.

For periods beyond 2034, 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 DEP EE programs implemented since 2007 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 2034. 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 1,579 GWh of Gross energy savings.

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

Base Case MWh Load Impacts of EE Programs								
	Annual MWh Load Reduction - Gross				Annual MWh Load Reduction - Net			
	Including measures added in 2015 and beyond			Including measures added since 2007	Including measures added in 2015 and beyond			Including measures added since 2007
Year	Post SB-3 EE	DSDR	Total		Post SB-3 EE	DSDR	Total	
2007-14				1,579,547				1,125,729
2015	359,333	48,966	408,298	1,987,845	305,807	48,966	354,773	1,480,501
2016	595,991	49,610	645,601	2,225,148	486,109	49,610	535,719	1,661,448
2017	830,926	50,213	881,139	2,460,686	663,551	50,213	713,763	1,839,492
2018	1,068,095	50,819	1,118,914	2,698,461	842,447	50,819	893,266	2,018,995
2019	1,303,235	51,441	1,354,676	2,934,223	1,019,152	51,441	1,070,593	2,196,322
2020	1,538,376	52,065	1,590,440	3,169,987	1,195,857	52,065	1,247,922	2,373,651
2021	1,773,516	52,577	1,826,093	3,405,640	1,372,562	52,577	1,425,139	2,550,868
2022	2,008,656	53,112	2,061,769	3,641,315	1,549,267	53,112	1,602,379	2,728,108
2023	2,243,797	53,695	2,297,492	3,877,039	1,725,972	53,695	1,779,667	2,905,396
2024	2,478,937	54,363	2,533,300	4,112,847	1,902,677	54,363	1,957,040	3,082,769
2025	2,714,078	54,960	2,769,038	4,348,585	2,079,382	54,960	2,134,343	3,260,072
2026	2,949,218	55,607	3,004,825	4,584,372	2,256,087	55,607	2,311,694	3,437,423
2027	3,184,358	56,244	3,240,602	4,820,149	2,432,792	56,244	2,489,037	3,614,765
2028	3,419,499	56,981	3,476,479	5,056,026	2,609,497	56,981	2,666,478	3,792,207
2029	3,654,639	57,563	3,712,203	5,291,749	2,786,203	57,563	2,843,766	3,969,495
2030	3,889,779	58,275	3,948,055	5,527,601	2,962,908	58,275	3,021,183	4,146,912

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 DEP DSM.

Base Case Load Impacts of DSM Programs								
	Annual Peak MW Reduction - Gross				Annual Peak MW Reduction - Net			
Year	DSM	DSDR	Pre SB-3 Programs	Total Annual Peak	DSM	DSDR	Pre SB-3 Programs	Total Annual Peak
2015	289	324	274	888	289	324	274	888
2016	330	329	277	936	330	329	277	936
2017	376	333	280	989	376	333	280	989
2018	415	337	283	1,035	415	337	283	1,035
2019	447	341	285	1,073	447	341	285	1,073
2020	458	345	288	1,091	458	345	288	1,091
2021	462	349	289	1,100	462	349	289	1,100
2022	463	352	289	1,104	463	352	289	1,104
2023	463	356	289	1,108	463	356	289	1,108
2024	463	360	289	1,113	463	360	289	1,113
2025	463	365	289	1,117	463	365	289	1,117
2026	463	369	289	1,122	463	369	289	1,122
2027	463	373	289	1,126	463	373	289	1,126
2028	463	378	289	1,131	463	378	289	1,131
2029	463	382	289	1,135	463	382	289	1,135
2030	463	388	289	1,141	463	388	289	1,141

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

EE Savings Variance since last IRP

In response to Recommendation Number 9 from the Public Staff, the Base Case EE savings forecast of MW and MWh was compared to the 2014 IRP and the cumulative achievements projected in the 2015 IRP at year 15 of the forecast are approximately 13.5% higher than the cumulative achievements in the 2014 IRP for the same time period as shown in the table below. As mentioned above, this is primarily due to adopting a revised forecast methodology that better aligns with the method used in the DEC IRP. Also, new programs have been added to the DEP forecast that are expected to increase the EE savings as compared to last year, specifically the expansion of the My Home Energy Report into the DEP territory, the Multi Family EE Program and the Energy Efficiency Education program.

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 2007	Including measures added in 2015 and beyond	Including measures added since 2007	% Change from 2014 to 2015 IRP
2014	225,214	1,368,084		1,579,547	15.5%
2015	467,656	1,610,527	359,333	1,938,879	20.4%
2016	724,195	1,867,066	595,991	2,175,537	16.5%
2017	915,163	2,058,034	830,926	2,410,473	17.1%
2018	1,135,353	2,278,223	1,068,095	2,647,642	16.2%
2019	1,381,341	2,524,212	1,303,235	2,882,782	14.2%
2020	1,644,724	2,787,595	1,538,376	3,117,922	11.8%
2021	1,918,355	3,061,226	1,773,516	3,353,063	9.5%
2022	2,185,183	3,328,054	2,008,656	3,588,203	7.8%
2023	2,444,434	3,587,305	2,243,797	3,823,344	6.6%
2024	2,695,143	3,838,014	2,478,937	4,058,484	5.7%
2025	2,894,882	4,037,753	2,714,078	4,293,624	6.3%
2026	3,074,232	4,217,103	2,949,218	4,528,765	7.4%
2027	3,230,876	4,373,747	3,184,358	4,763,905	8.9%
2028	3,362,169	4,505,040	3,419,499	4,999,046	11.0%
2029	3,467,037	4,609,908	3,654,639	5,234,186	13.5%
2030	3,531,384	4,674,255	3,889,779	5,469,326	17.0%

At this time, there is significant uncertainty in the development of new technologies that will impact the level of EE achievement from future programs and/or enhancements to existing programs, as well as in the ability to secure high levels of customer participation, to risk including the high EE savings projection in the base assumptions for developing the 2015 IRP. DEP expects that over time, as EE programs are implemented, the Company will continue to gain experience and evidence on the viability of the level of EE achieved given actual customer participation. As information becomes available on actual participation, technology changes, and EE achievement, then the EE savings forecast used for integrated resource planning purposes will be revised in future IRP's to reflect the most realistic projection of EE savings.

Programs Evaluated but Rejected

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

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

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

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

The DSDR program achieved 247 incremental MW of voltage reduction, based upon the 2007 distribution system summer peak. The incremental voltage reduction from the DSDR project does not include the previously available 75 MW of voltage reduction capabilities, which is added to the DSDR capabilities for the gross total.

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

Program Savings by Source (at T/D substation)

Year	Peak MW Demand Savings			MWh Energy Savings		
	Voltage Reduction	Reduced Line Losses	All Sources	Voltage Reduction	Reduced Line Losses	All Sources
2015	318	6	324	16,986	31,979	48,966
2016	322	6	329	17,207	32,404	49,610
2017	326	6	333	17,424	32,789	50,213
2018	330	6	337	17,632	33,187	50,819
2019	334	6	341	17,851	33,590	51,441
2020	338	7	345	18,063	34,002	52,065
2021	342	7	349	18,262	34,315	52,577
2022	346	7	352	18,445	34,667	53,112
2023	349	7	356	18,643	35,052	53,695
2024	354	7	360	18,868	35,495	54,363
2025	358	7	365	19,093	35,867	54,960
2026	362	7	369	19,322	36,285	55,607
2027	366	7	373	19,545	36,699	56,244
2028	371	7	378	19,800	37,180	56,981
2029	375	7	382	20,024	37,539	57,563

Discontinued Demand Side Management and Energy Efficiency Programs

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

- Residential Energy Efficient Benchmarking Program – This program ended in July 2014 and was subsequently replaced with the Residential My Home Energy Report (MyHER) Program, which received regulatory approval during the second half of 2014.

Current and Anticipated Consumer Education Programs

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

- On Line Account Access
- “Lower My Bill” Toolkit
- Online Energy Saving Tips
- Energy Resource Center

- Large Account Management
- eSMART Kids Website
- Community Events

On Line Account Access

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

"Lower My Bill" Toolkit

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

Online Energy Saving Tips

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

Energy Resource Center

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

Large Account Management

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

e-SMART Kids Website

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

Community Events

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

Discontinued Consumer Education Programs

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

7. DEVELOPMENT OF RESOURCE PLAN

The following section details the Company's expansion plan and resource mix that is required to meet the needs of DEP'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 Progress 2015 Annual Plan

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Forecast															
1 Duke System Peak	13,048	13,224	13,402	13,595	13,949	14,208	14,444	14,709	14,901	15,082	15,264	15,440	15,636	15,814	15,981
2 Firm Sale	150	150	150	150	150	150	150	150	150	0	0	0	0	0	0
3 Cumulative New EE Programs	(67)	(96)	(125)	(155)	(183)	(212)	(239)	(265)	(290)	(313)	(330)	(342)	(344)	(349)	(352)
4 Adjusted Duke System Peak	**13,131**	**13,277**	**13,427**	**13,590**	**13,916**	**14,146**	**14,355**	**14,595**	**14,761**	**14,770**	**14,934**	**15,098**	**15,292**	**15,465**	**15,629**
Existing and Designated Resources															
5 Generating Capacity	12,776	12,776	12,813	12,828	12,963	13,194	12,844	12,844	12,844	12,844	12,844	12,844	12,664	12,664	12,664
6 Designated Additions / Uprates	0	98	15	135	1,013	0	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	(61)	0	0	(782)	(350)	0	0	0	0	0	(180)	0	0	(741)
8 Cumulative Generating Capacity	**12,776**	**12,813**	**12,828**	**12,963**	**13,194**	**12,844**	**12,844**	**12,844**	**12,844**	**12,844**	**12,844**	**12,664**	**12,664**	**12,664**	**11,923**
Purchase Contracts															
9 Cumulative Purchase Contracts	**1,919**	**1,930**	**1,930**	**1,761**	**1,616**	**861**	**528**	**528**	**528**	**528**	**478**	**477**	**452**	**419**	**407**
Non-Compliance Renewable Purchases	177	188	188	188	188	132	131	130	130	130	80	80	58	25	12
Non-Renewables Purchases	1,742	1,742	1,742	1,574	1,429	729	397	397	397	397	397	397	394	394	394
Undesignated Future Resources															
10 Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Combined Cycle	0	0	0	0	0	895	895	0	0	0	0	0	0	0	895
12 Combustion Turbine	0	0	0	0	0	828	0	0	0	0	0	828	0	0	0
13 CHP	0	0	0	20	0	20	0	0	0	0	0	0	0	0	0
Renewables															
14 **Cumulative Renewables Capacity**	437	473	433	434	437	348	347	619	637	645	639	653	667	677	666
15 Cumulative Production Capacity	**15,132**	**15,217**	**15,191**	**15,179**	**15,268**	**15,816**	**16,378**	**16,648**	**16,666**	**16,674**	**16,618**	**17,280**	**17,269**	**17,246**	**17,377**
Demand Side Management (DSM)															
16 Cumulative DSM Capacity	**871**	**923**	**967**	**1,004**	**1,021**	**1,029**	**1,032**	**1,034**	**1,037**	**1,040**	**1,043**	**1,046**	**1,049**	**1,052**	**1,055**
17 Cumulative Capacity w/ DSM	**16,003**	**16,140**	**16,159**	**16,183**	**16,288**	**16,845**	**17,409**	**17,683**	**17,703**	**17,715**	**17,662**	**18,326**	**18,319**	**18,298**	**18,432**
Reserves w/ DSM															
18 Generating Reserves	2,872	2,862	2,732	2,593	2,372	2,698	3,054	3,088	2,942	2,945	2,728	3,228	3,027	2,832	2,803
19 % Reserve Margin	**21.9%**	**21.6%**	**20.3%**	**19.1%**	**17.0%**	**19.1%**	**21.3%**	**21.2%**	**19.9%**	**19.9%**	**18.3%**	**21.4%**	**19.8%**	**18.3%**	**17.9%**

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

**Winter Projections of Load, Capacity, and Reserves
for Duke Energy Progress 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	12,767	12,938	13,133	13,342	13,531	13,703	13,882	14,062	14,278	14,437	14,621	14,797	15,022	15,183
2 Firm Sale	150	150	150	150	150	150	150	150	150	0	0	0	0	0
3 Cumulative New EE Programs	(40)	(62)	(84)	(105)	(129)	(151)	(171)	(190)	(209)	(226)	(240)	(249)	(250)	(253)
4 Adjusted Duke System Peak	**12,877**	**13,027**	**13,200**	**13,386**	**13,553**	**13,702**	**13,861**	**14,022**	**14,220**	**14,211**	**14,381**	**14,548**	**14,772**	**14,930**
Existing and Designated Resources														
5 Generating Capacity	13,895	13,899	13,917	13,935	14,289	13,772	13,772	13,772	13,772	13,772	13,772	13,772	13,540	13,540
6 Designated Additions / Uprates	4	94	18	733	350	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	(76)	0	(379)	(867)	0	0	0	0	0	0	(232)	0	0
8 Cumulative Generating Capacity	**13,899**	**13,917**	**13,935**	**14,289**	**13,772**	**13,772**	**13,772**	**13,772**	**13,772**	**13,772**	**13,772**	**13,540**	**13,540**	**13,540**
Purchase Contracts														
9 Cumulative Purchase Contracts	**2,006**	**2,017**	**2,017**	**2,017**	**1,704**	**1,148**	**502**	**502**	**502**	**502**	**452**	**452**	**441**	**434**
Non-Compliance Renewable Purchas	126	137	137	137	137	81	80	80	80	80	30	30	22	15
Non-Renewables Purchases	1,880	1,880	1,880	1,880	1,567	1,066	422	422	422	422	422	422	419	419
Undesignated Future Resources														
10 Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11 Combined Cycle	0	0	0	0	0	935	935	0	0	0	0	0	0	0
12 Combustion Turbine	0	0	0	0	0	878	0	0	0	0	0	878	0	0
13 CHP	0	0	0	20	0	20	0	0	0	0	0	0	0	0
Renewables														
13 **Cumulative Renewables Capacity**	222	257	216	216	218	129	129	178	174	177	176	179	178	183
14 Cumulative Production Capacity	**16,127**	**16,191**	**16,168**	**16,542**	**15,714**	**16,901**	**17,191**	**17,240**	**17,236**	**17,239**	**17,188**	**17,837**	**17,826**	**17,823**
Demand Side Management (DSM)														
15 Cumulative DSM Capacity	**531**	**552**	**569**	**583**	**595**	**606**	**610**	**613**	**617**	**621**	**624**	**628**	**631**	**634**
16 Cumulative Capacity w/ DSM	**16,658**	**16,743**	**16,737**	**17,125**	**16,310**	**17,508**	**17,800**	**17,853**	**17,853**	**17,860**	**17,813**	**18,464**	**18,456**	**18,457**
Reserves w/ DSM														
17 Generating Reserves	3,781	3,716	3,537	3,739	2,757	3,806	3,940	3,831	3,633	3,648	3,432	3,916	3,684	3,527
18 % Reserve Margin	**29.4%**	**28.5%**	**26.8%**	**27.9%**	**20.3%**	**27.8%**	**28.4%**	**27.3%**	**25.6%**	**25.7%**	**23.9%**	**26.9%**	**24.9%**	**23.6%**

DEP - Assumptions of Load, Capacity, and Reserves Table

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

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

2. Firm sale of 150 MW through 2024.

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

4. Peak load adjusted for firm sales and cumulative energy efficiency.

5. Existing generating capacity reflecting designated additions, planned uprates, retirements and derates as of January 1, 2015.

   Includes total unit capacity of jointly owned units.

6. Capacity Additions include:

   Planned nuclear uprates totaling 29 MW in the 2017-2018 timeframe.

   Planned combined cycle uprates totaling 135 MW in 2019.

   84 MW Sutton Blackstart combustion turbine addition in 2017.

   A short-term 350 MW PPA is included in 2020, and removed in the fall of 2020.

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

7. Planned Retirements include:

   Sutton CT Units 1, 2A and 2B in 2017 (61 MW).

   Darlington CT Units 1-11 by 2020 (553 MW).

   Blewett CT Units 1-4 and Weatherspoon CT units 1-4 in 2027 (180 MW).

   Robinson 2 in 2030 (741 MW).

8. Sum of lines 5 through 7.

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

9. Cumulative Purchase Contracts have several components:

   Purchased capacity from PURPA Qualifying Facilities, Anson and Hamlet CT tolling, Butler Warner purchase, Southern CC purchase, and Broad River CT purchase.

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

10. New nuclear resources economically selected to meet load and minimum planning reserve margin Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of that year.

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

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

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

    Addition of 895 MW of combined cycle capacity in 2021, 2022 and 2030.

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

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

    Addition of 828 MW of combustion turbine capacity in 2021 and 2027.

13. New CHP resources. 20 MW in 2019 and 20 MW in 2021.

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

    Also includes utility-owned solar.

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

15. Sum of lines 8 through 14.

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

17. Sum of lines 15 and 16.

18. The difference between lines 17 and 4.

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

    Line 18 divided by Line 4.

    Minimum target planning reserve margin is 17%.

Technologies Considered

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 IRP 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, 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 DEP Base Case Resources– Summer (with CO_2)

Duke Energy Progress Resource Plan [1] Base Case - Summer						
Year	Resource			MW		
2016	-			-		
2017	Sutton Blackstart CTs	Nuclear Uprates		84	14	
2018	Nuclear Uprates			15		
2019	CC Uprates	CHP		135	20	
2020	Asheville CC			663		
2021	New CC	New CT	CHP	895	828	20
2022	New CC			895		
2023	-			-		
2024	-			-		
2025	-			-		
2026	-			-		
2027	New CT			828		
2028	-			-		
2029	-			-		
2030	New CC			895		

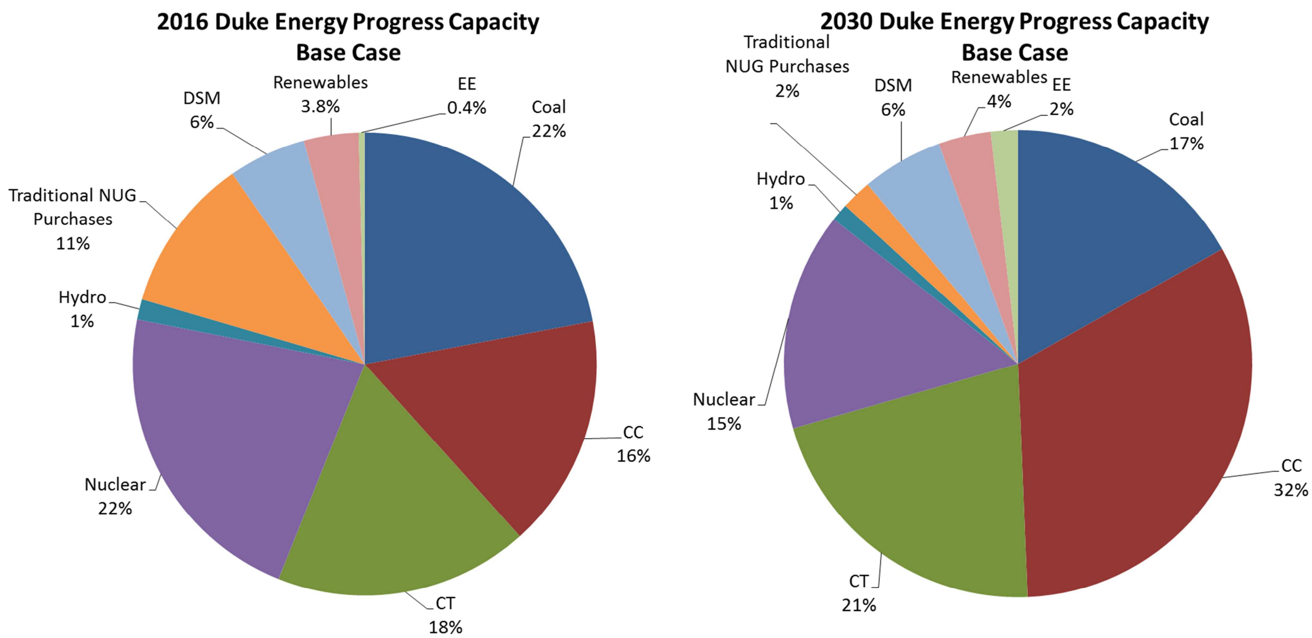
Notes: (1) Table includes both designated and undesignated capacity additions

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

DEP Base Case Resources Cumulative Summer Totals - 2016 - 2030	
Nuclear	29
CC	3483
CT	1740
CHP	40
Total	5292

The following charts illustrate both the current and forecasted capacity by fuel type for the DEP system, as projected in the Base Case. As demonstrated in Chart 7-A, the capacity mix for the DEP system changes with the passage of time. In 2030, the Base Case projects that DEP 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 Progress Resource Plan [1] No Carbon Sensitivity - Summer					
Year	**Resource**			**MW**		
2016	-			-		
2017	Sutton Blackstart CTs	Nuclear Uprates		84	14	
2018	Nuclear Uprates			15		
2019	CC Uprates	CHP		135	20	
2020	Asheville CC			663		
2021	New CT	New CC	CHP	828	895	20
2022	New CT			414		
2023	-			-		
2024	New CT			414		
2025	-			-		
2026	-			-		
2027	New CT			414		
2028	New CT			414		
2029	-			-		
2030	New CT			1242		

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

Table 7-F No Carbon Sensitivity Cumulative Summer Totals

DEP No Carbon Sensitivity Resources Cumulative Summer Totals - 2016 - 2030	
Nuclear	29
CC	1693
CT	3810
CHP	40
Total	5572

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 DEP will increase these resources:

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

- Continue on-going work to develop and implement additional cost-effective EE and DSM products and services. Since the last biennial IRP, DEP has implemented the following new program offerings: Residential New Construction Program, Energy Efficient Lighting Program and Small Business Energy Saver Program.

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

- Over the 5 year period represented in the Short-Term Action Plan, DEP projects to add an incremental 115 MW of EE and 149 MW of DSM.

Continued Focus on Renewable Energy Resources

- DEP 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, DEP continues to procure renewable purchase power resources, when economically viable, as part of its Compliance Plans. DEP is also pursuing the addition of new utility-owned solar on the DEP system.

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

- DEC continues to pursue CHP opportunities, as appropriate.

Addition of Clean Natural Gas Resources

- Begin construction on the Sutton Blackstart CTs in 2016 to be available for the summer peak of 2017. The Company's petition for a Certificate of Public Convenience and Necessity (CPCN) was approved by the NCUC with an order issued on August 3, 2015.

- Pursue the addition of a new combined cycle at the Asheville facility in the 2019 timeframe as part of the WCMP.

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

- Take actions to ensure capacity needs beginning in 2021 are met. In addition to seeking to meet the Company's EE and DSM goals and meeting the Company's NC REPS and SC DERP requirements, actions to secure additional capacity may include purchased power, short-term PPAs or Company-owned generation. The 2015 IRP projects that the best resources to meet this 2021 demand are combined cycle units.

- Placeholder for a short-term PPA of 350 MW is included in 2017 to meet 17% reserve margin. This will continue to be reviewed in future IRPs.

Expiration of Wholesale Purchase Contracts (CONFIDENTIAL)

In the 2016-2020 timeframe, DEP has [redacted] of wholesale purchase contracts that are scheduled to expire. At this time, DEP 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-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 Purchase Contract Expirations (CONFIDENTIAL)

[redacted]

Continued Focus on System Reliability and Resource Adequacy for DEP System

As previously stated, DEP has retained Astrape Consulting to conduct a reserve margin study to examine the resource adequacy of the DEP system. Based upon the recent extreme winter weather, the potential for continued extreme weather, and the large amount of expected solar 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 loss of load expectation (LOLE). As such, DEP 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 350 MW purchased power agreement (PPA) in 2020 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.

<u>Continued Focus on Regulatory, Environmental Compliance & Wholesale Activities</u>

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

- Retire Asheville coal units. The Company expects to retire the existing Asheville coal units no later than January 31, 2020 and replace with new combined cycle generation as part of the WCMP. The Asheville units have a combined capacity of 376 MW.

- 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 reference plan in the 2015 IRP is shown in Table 8-B 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-B DEP Short-Term Action Plan

Duke Energy Progress Short-Term Action Plan

			Compliance Renewable Resources (Cumulative Nameplate MW)			Other Non-Compliance Renewables (Cumulative Nameplate MW) (4)		
Year	Retirements	Additions	Wind (1)	Solar (1)	Biomass/Hydro (3)	Solar/Biomass/Hydro	EE	DSM (2)
2016			0	459	171	397	67	871
2017	61 MW Sutton CTs (Units 1, 2A, 2B)	84 MW Sutton Blackstart CTs 14 MW Nuc Uprate	0	462	206	409	96	923
2018		15 MW Nuc Uprate	0	465	164	408	125	967
2019		20 MW CHP 135 MW CC Uprate	0	467	164	407	155	1004
2020	406 MW Darlington CT (Units 1-3, 5, 7-10) 376 MW Asheville Coal	663 MW Asheville CC 350 MW CT PPA (5)	0	468	167	407	183	1021

Notes:

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

(2) Includes impacts of grid modernization.

(3) Biomass includes swine and poultry contracts.

(4) Other renewables includes NUGs and utility-owned projects.

(4) This is a placeholder PPA for 2020, and removed in 2021.

9. OWNED GENERATION

DUKE ENERGY PROGRESS OWNED GENERATION

Duke Energy Progress' generation portfolio includes a balanced mix of resources with different operating and fuel characteristics. This mix is designed to provide energy at the lowest reasonable cost to meet the Company's obligation to serve its customers. Duke Energy Progress-owned generation, as well as purchased power, is evaluated on a real-time basis in order to select and dispatch the lowest-cost resources to meet system load requirements. In 2014, Duke Energy Progress' nuclear and coal-fired generating units met the vast majority of customer needs by providing 46% and 26%, respectively, of Duke Energy Progress' energy from generation. Hydroelectric generation, Combustion Turbine generation, Combined Cycle generation, solar generation, long term PPAs, and economical purchases from the wholesale market supplied the remainder.

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

Existing Generating Units and Ratings [1, 3]
All Generating Unit Ratings are as of December 31, 2014 unless otherwise noted.

Coal						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Asheville	1	192	191	Arden, NC	Coal	Base
Asheville	2	187	185	Arden, NC	Coal	Base
Mayo [2]	1	746	727	Roxboro, NC	Coal	Base
Roxboro	1	380	379	Semora, NC	Coal	Base
Roxboro	2	673	671	Semora, NC	Coal	Base
Roxboro	3	698	691	Semora, NC	Coal	Base
Roxboro [2]	4	711	698	Semora, NC	Coal	Base
Total Coal		3,587	3,542			

Combustion Turbines						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Asheville	3	185	164	Arden, NC	Natural Gas/Oil	Peaking
Asheville	4	185	160	Arden, NC	Natural Gas/Oil	Peaking
Blewett	1	17	13	Lilesville, NC	Oil	Peaking
Blewett	2	17	13	Lilesville, NC	Oil	Peaking
Blewett	3	17	13	Lilesville, NC	Oil	Peaking
Blewett	4	17	13	Lilesville, NC	Oil	Peaking
Darlington	1	63	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	2	64	48	Hartsville, SC	Oil	Peaking
Darlington	3	63	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	4	66	50	Hartsville, SC	Oil	Peaking
Darlington	5	66	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	6	62	45	Hartsville, SC	Oil	Peaking
Darlington	7	65	51	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	8	66	48	Hartsville, SC	Oil	Peaking
Darlington	9	65	52	Hartsville, SC	Oil	Peaking
Darlington	10	65	51	Hartsville, SC	Oil	Peaking
Darlington	11	67	52	Hartsville, SC	Oil	Peaking
Darlington	12	133	118	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	13	133	116	Hartsville, SC	Natural Gas/Oil	Peaking
Smith [4]	1	183	157	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	2	183	156	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	3	185	155	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	4	186	159	Hamlet, NC	Natural Gas/Oil	Peaking
Smith [4]	6	187	153	Hamlet, NC	Natural Gas/Oil	Peaking
Sutton	1	12	11	Wilmington, NC	Oil/Natural Gas	Peaking
Sutton	2A	31	24	Wilmington, NC	Oil/Natural Gas	Peaking
Sutton	2B	33	26	Wilmington, NC	Oil/Natural Gas	Peaking
Wayne	1/10	192	177	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	2/11	192	174	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	3/12	193	173	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	4/13	185	170	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	5/14	197	169	Goldsboro, NC	Oil/Natural Gas	Peaking
Weatherspoon	1	41	32	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	2	41	32	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	3	41	33	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	4	41	31	Lumberton, NC	Natural Gas/Oil	Peaking
Total NC		2,561	2,208			
Total SC		978	787			
Total CT		3,539	2,995			

Combined Cycle						
	Unit	**Winter (MW)**	**Summer (MW)**	**Location**	**Fuel Type**	**Resource Type**
Lee	CT1A	223	177	Goldsboro, NC	Natural Gas/Oil	Base
Lee	CT1B	222	176	Goldsboro, NC	Natural Gas/Oil	Base
Lee	CT1C	223	179	Goldsboro, NC	Natural Gas/Oil	Base
Lee	ST1	379	378	Goldsboro, NC	Natural Gas/Oil	Base
Smith [4]	CT7	189	160	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT8	189	157	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	ST4	175	165	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT9	214	178	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	CT10	214	178	Hamlet, NC	Natural Gas/Oil	Base
Smith [4]	ST5	246	250	Hamlet, NC	Natural Gas/Oil	Base
Sutton	CT1A	225	179	Wilmington, NC	Natural Gas/Oil	Base
Sutton	CT1B	225	179	Wilmington, NC	Natural Gas/Oil	Base
Sutton	ST1	267	264	Wilmington, NC	Natural Gas/Oil	Base
Total CC		2,991	2,620			

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

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

Total Generation Capability		
	Winter Capacity (MW)	Summer Capacity (MW)
TOTAL DEP SYSTEM - N.C.	12,267	11,395
TOTAL DEP SYSTEM - S.C.	1,775	1,528
TOTAL DEP SYSTEM	14,042	12,923

Note 1: Ratings reflect compliance with NERC reliability standards and are gross of co-ownership interest as of 12/31/14.
Note 2: DEP's purchase of NCEMPA's interest in these power plants was closed on July 31, 2015. DEP is now 100% owner of these previously jointly owned assets.
Note 3: Resource type based on NERC capacity factor classifications which may alternate over the forecast period.
Note 4: Richmond County Plant renamed to Sherwood H. Smith Jr. Energy Complex.

Planned Uprates			
Unit	**Date**	**Winter MW**	**Summer MW**
Brunswick 2 [1]	June 2017	10	10
Harris 1 [1]	June 2017	4	4
Harris 1[1]	June 2019	15	15
Lee CC CT1A [1]	May 2019	25.7	25.7
Lee CC CT1B [1]	May 2019	25.7	25.7
Lee CC CT1C [1]	May 2019	25.7	25.7
Sutton CC CT1A [1]	May 2019	29.0	29.0
Sutton CC CT1B [1]	May 2019	29.0	29.0

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

Retirements				
Unit & Plant Name	**Location**	**Capacity (MW) Winter / Summer**	**Fuel Type**	**Retirement Date**
Cape Fear 5	Moncure, NC	148 / 144	Coal	10/1/12
Cape Fear 6	Moncure, NC	175 / 172	Coal	10/1/12
Cape Fear 1A	Moncure, NC	14 / 11	Combustion Turbine	3/31/13
Cape Fear 1B	Moncure, NC	14 / 12	Combustion Turbine	3/31/13
Cape Fear 2A	Moncure, NC	15 / 12	Combustion Turbine	3/31/13
Cape Fear 2B	Moncure, NC	14 / 11	Combustion Turbine	10/1/12
Cape Fear 1	Moncure, NC	12 / 11	Steam Turbine	3/31/11
Cape Fear 2	Moncure, NC	12 / 7	Steam Turbine	3/31/11
Lee 1	Goldsboro, NC	80 / 74	Coal	9/15/12
Lee 2	Goldsboro, NC	80 / 68	Coal	9/15/12
Lee 3	Goldsboro, NC	252 / 240	Coal	9/15/12
Lee 1	Goldsboro, NC	15 / 12	Combustion Turbine	10/1/12
Lee 2	Goldsboro, NC	27 / 21	Combustion Turbine	10/1/12
Lee 3	Goldsboro, NC	27 / 21	Combustion Turbine	10/1/12
Lee 4	Goldsboro, NC	27 / 21	Combustion Turbine	10/1/12
Morehead 1	Morehead City, NC	15 / 12	Combustion Turbine	10/1/12
Robinson 1	Hartsville, NC	179 / 177	Coal	10/1/12
Robinson 1	Hartsville, NC	15 / 11	Combustion Turbine	3/31/13
Weatherspoon 1	Lumberton, NC	49 / 48	Coal	9/30/11
Weatherspoon 2	Lumberton, NC	49 / 48	Coal	9/30/11
Weatherspoon 3	Lumberton, NC	79 / 74	Coal	9/30/11
Sutton 1	Wilmington, NC	98 / 97	Coal	11/27/13
Sutton 2	Wilmington, NC	95 / 90	Coal	11/27/13
Sutton 3	Wilmington, NC	389 / 366	Coal	11/4/13
Total		1,880 MW / 1,760 MW		

Planning Assumptions – Unit Retirements[a]

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

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

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

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

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

10. CONCLUSIONS

DEP 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 DEP 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, DEP expects to require 5,292 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, DEP's 2015 IRP focuses on the following:

- Begin construction on the Sutton Blackstart CTs in 2016 to be available for the summer peak of 2017.
- Pursue the addition of a new combined cycle at the Asheville facility in the 2019 timeframe as part of the WCMP.
- Take actions to ensure capacity needs beginning in 2021 are met.
- 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 and invest in additional cost-effective renewable resources.
- Continue to invest in EE and DSM in the Carolinas region.

Long-Term

Beyond the next 5 years, DEP'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 combustion turbine 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 DEP system.
- Continue to invest in DSM in the Carolinas region.

DEP's goal is to continue to diversify the DEP 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, renewables, and EE and DSM.

11. NON-UTILITY GENERATION AND 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]