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November 6, 2020

VIA ELECTRONIC FILING

Ms. Kimberley A. Campbell
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Carolinas, LLC 2020 Integrated Resource Plan Corrections
Docket No. E-100, Sub 165

Dear Ms. Campbell:

On September 1, 2020 Duke Energy Carolinas, LLC ("DEC") filed its 2020 Integrated Resource Plan ("IRP"). Through the instant filing, the Company is submitting certain ministerial revisions to the IRP and Attachment I, to correct typographical mistakes and make other non-substantive corrections that have come to the Company's attention. These changes are enumerated in the Table of Corrections document attached hereto. The Company has also corrected several formatting issues in the IRP where tables and information were overlaid and did not read clearly, or graphs were presented blurry and were unreadable.

To that end, I enclose the following documents:

(1) DEC's corrected IRP, which is marked "Corrected 11.06.2020" in the left-hand footer;
(2) The 23 pages of the IRP that were corrected (these are being filed separately for ease of identification)
(3) Attachment I (Public Version), which is marked "Corrected 11.06.2020" in the left-hand footer; and
(4) The Table of Corrections detailing the corrections made in the IRP and Attachment I.

DEC respectfully renews its request that data in Table 2 of Attachment I to the IRP be treated confidentially pursuant to N.C. Gen. Stat. § 132-1.2, for the reasons cited in the September 1, 2020 filing.

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

Sincerely,

Lawrence B. Somers

Enclosures

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that Duke Energy Carolinas, LLC's Integrated Resource Plan Corrections, in Docket No. E-100, Sub 165, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to the following parties of record

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This the 6th day of November, 2020.

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DOCKET NO. E-100, SUB 165

DUKE ENERGY CAROLINAS INTEGRATED RESOURCE PLAN

2020

Corrected 11.06.2020

DUKE ENERGY CAROLINAS 2020 INTEGRATED RESOURCE PLAN CONTENTS

Corrected 11.06.2020

ATTACHMENTS FILED AS SEPARATE DOCUMENTS:

1 EXECUTIVE SUMMARY

As one of the largest investor-owned utilities in the country, Duke Energy has a strong history of delivering affordable, reliable and increasingly cleaner energy to our customers. In planning for the future, the Company is transforming the way it does business by investing in increasingly cleaner resources, modernizing the grid and transforming the customer experience. Duke Energy Carolinas (DEC), a public utility subsidiary of Duke Energy, owns nuclear, coal, natural gas, renewables and hydroelectric generation. That diverse fuel mix provides about 23,200 megawatts (MW) of owned electricity capacity to 2.7 million customers in a 24,000 square-mile service area of North Carolina and South Carolina.

As required by North Carolina Utilities Commission (NCUC) Rule R8-60 and subsequent orders, the Public Service Commission of South Carolina (PSCSC) and The Energy Freedom Act (Act 62) in South Carolina, Duke Energy Carolinas is submitting its 2020 Integrated Resource Plan (IRP). The IRP balances resource adequacy and capacity to serve anticipated peak electrical load, consumer affordability and least cost, as well as compliance with applicable state and federal environmental regulations. The IRP details potential resource portfolios to match forecasted electricity requirements, including an appropriate reserve margin, to maintain system reliability for customers over the next 15 years. In addition to meeting regulatory and statutory obligations, the IRP is intended to provide insight into the Company's planning processes.

DEC operates as a single utility system across both states and is filing a single system IRP in both North Carolina and South Carolina. As such, the quantitative analysis contained in both the North Carolina and South Carolina filings is identical, although certain sections dealing with state-specific issues such as state renewable standards or environmental standards may be unique to individual

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state requirements. The IRP to be filed in each state is identical in form and content. It is important to note that DEC cannot fulfill two different IRPs for one system. Accordingly, it is in customers' and the Company's interest that the resulting IRPs accepted or approved in each state are consistent with one another.

In alignment with the Company's climate strategy, input from a diverse range of stakeholders, and other policy initiatives, the 2020 IRP projects potential pathways for how the Company's resource portfolio may evolve over the 15-year period (2021 through 2035) based on current data and assumptions across a variety of scenarios. As a regulated utility, the Company is obligated to develop an IRP based on the policies in effect at that time. As such, the IRP includes a base plan without carbon policy that represents existing policies under least-cost planning principles. To show the impact potential new policies may have on future resource additions and in response to stakeholder feedback, the 2020 IRP also introduces a variety of portfolios that evaluate more aggressive carbon emission reduction targets. As described throughout the IRP, these portfolios have trade-offs between the pace of carbon reductions weighted against the associated cost and operational considerations. These portfolios will ultimately be shaped by the pace of carbon reduction targeted by future policies and the rate of maturation of new, clean technologies.

Inputs to the IRP modeling process, such as load forecasts, fuel and technology price curves and other factors are derived from multiple sources including third party providers such as Guidehouse, IHS, Burns and McDonnell, and other independent sources such as the Energy Information Administration (EIA) and National Renewable Energy Laboratory (NREL). These inputs reflect a "snapshot in time," and modeling results and resource portfolios will evolve over time as technology costs and load forecasts change. The plan includes different resource portfolios with different assumptions around coal retirement and carbon policy but recognizes that the modeling process is limited in its ability to consider all potential policy changes and lacks perfect foresight of other variables such as technology advancements and economic factors. To the extent these factors change over time, future resource plans will reflect those changes.

To further inform the Company's planning efforts, in 2019, Duke Energy contracted with NREL[1] to conduct a Carbon-Free Resource Integration Study[2] to evaluate the planning and operational

[1] "An industry-respected, leading research institution that advances the science and engineering of energy efficiency, sustainable transportation and renewable power technologies", www.nrel.gov.

[2] https://www.nrel.gov/grid/carbon-free-integration-study.html.

considerations of integrating increasing levels of carbon-free resources onto the Duke Energy Carolinas and Duke Energy Progress systems. Phase 1 of the study[3] has helped inform some of the renewable resource assumptions and reinforced the benefits that a diverse portfolio can provide when integrating carbon-free generation on the system. Phase 2 of the NREL study is underway now. This study is being informed by stakeholder input and will provide a more granular analysis to understand the integration, reliability and operational challenges and opportunities for integrating carbon-free resources and will inform future IRPs and planning efforts.

In accordance with North Carolina and South Carolina regulatory requirements, the 2020 IRP includes a most economic or "least-cost" portfolio, as well as multiple scenarios reflecting a range of potential future resource portfolios. These portfolios compare the carbon reduction trajectory, cost, operability and execution implications of each portfolio to support the regulatory process and inform public policy dialogue. In North Carolina, Duke Energy is an active participant in the state's Clean Energy Plan stakeholder process, which is evaluating policy pathways to achieve a 70% reduction in greenhouse gas emissions from 2005 levels by 2030 and carbon neutrality for the electric power sector by 2050. Accordingly, this year's IRP includes two resource portfolios that illustrate potential pathways to achieve 70% CO_2 reduction by 2030, though both scenarios would require supportive state policies in North Carolina and South Carolina. All portfolios keep Duke Energy on a trajectory to meet its near-term enterprise carbon-reduction goal of at least 50% by 2030 and long-term goal of net-zero by 2050. These portfolios would also enable the Company to retire all units that rely exclusively on coal by 2030. Looking beyond the planning horizon, the 2020 IRP includes a section that provides a qualitative overview of how technologies, analytical tools and processes, and the grid will need to evolve to achieve the Company's net-zero 2050 CO_2 goal. Duke Energy welcomes the opportunity to work constructively with policymakers and stakeholders to address technical and practical issues associated with these scenarios.

Act 62, which was signed into law in South Carolina on May 16, 2019, sets out minimum requirements for each utility's IRP. The 2020 IRP contains the necessary information required by Act 62, including, the utility's long-term forecast of sales and peak demand under various scenarios, projected energy purchased or produced by the utility from renewable energy resources, and a summary of the electrical transmission investments planned by the utility.

[3] https://www.nrel.gov/grid/carbon-free-integration-study.html.

The IRP also includes resource portfolios developed with the purpose of fairly evaluating the range of demand side, supply side, storage, and other technologies and services available to meet the utility's service obligations. Consistent with Act 62 and NC requirements, the IRP balances the following factors: resource adequacy and capacity to serve anticipated peak electrical load with applicable planning reserve margins; consumer affordability and least cost; compliance with applicable state and federal environmental regulations; power supply reliability; commodity price risks; and diversity of generation supply.

EXECUTIVE SUMMARY

Duke Energy's history of delivering reliable, affordable and increasingly cleaner energy to its customers in the Carolinas stems back to the early 1900's, when visionaries harnessed the natural resource of the Catawba River to develop an integrated system of hydropower plants that provided the electricity to attract new industries to the region. As the population in the Carolinas has grown and energy demand increased, the Company has worked collaboratively with customers and other stakeholders to invest in a diverse portfolio of generation resources, enabled by an increasingly resilient grid, to respond to the region's growing energy needs and economic growth.

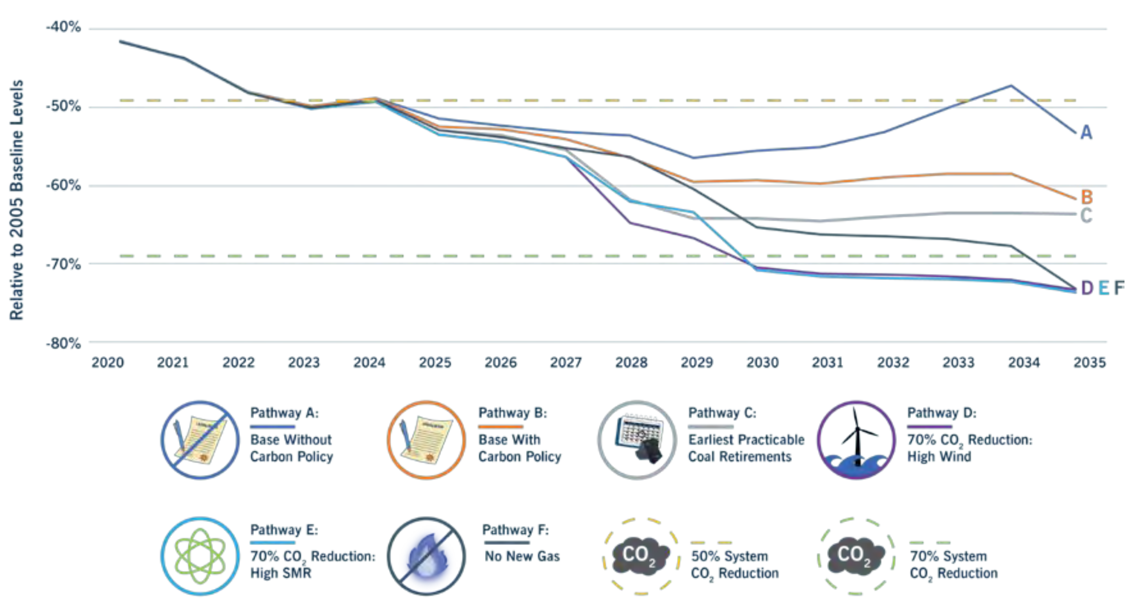
Today, Duke Energy Carolinas (DEC) serves approximately 2.7 million customers. Over the 15-year planning horizon, the Company projects the addition of 560,000 new customers in DEC contributing to 1,650 MW of additional winter peak demand on the system. Even with the expansion of energy efficiency and demand reduction programs contributing to declining per capita energy usage, cumulative annual energy consumption is expected to grow by approximately 7,200 GWh between 2021 and 2035 due to the projected population and household growth that exceeds the national average. This represents an annual winter peak demand growth rate of 0.6% and an annual energy growth rate of 0.5%. In addition to growing demand, DEC is planning for the potential retirement of some of its older, less efficient generation resources, creating an additional need of at least 3,925 MW over the 15-year planning horizon. After accounting for the required reserve margin, approximately 4,600 MW of new resources are projected to be needed over the 15-year planning horizon.

While growing, DEC is projecting slightly lower load growth compared to the 2019 IRP due to a somewhat weaker economic outlook, the addition of 2019 peak history showing declines in commercial and Industrial energy sales, and other refinements to the forecasting inputs. Additionally, due to the timing of the spring 2020 load forecast, which was developed using Moody's economic inputs as of January 2020, and the lack of relevant historical data upon which to base forecast adjustments, the potential impacts of COVID-19 are not incorporated in this forecast. Based on summer 2020 demand observations to date, however, it appears that the COVID-19 impact to peak demand is relatively insignificant. The Company will continue to monitor the impacts from the pandemic, including the higher residential demand and changing usage patterns, as well as the projected macroeconomic implications and incorporate changes to the long-term planning assumptions in future IRPs.

REDUCING GHG EMISSIONS

In 2019, Duke Energy announced a corporate commitment to reduce CO_2 emissions by at least 50% from 2005 levels by 2030, and to achieve net-zero by 2050. This is a shared goal important to the Company's customers and communities, many of whom have also developed their own clean energy initiatives. As one of the largest investor-owned utilities in the U.S., the goal to attain a net-zero carbon future represents one of the most significant reductions in CO_2 emissions in the U.S. power sector. The development of the Company's IRP and climate goals are complementary efforts, with the IRP serving as a road map that provides the analysis and stakeholder input that will be required to achieve carbon reductions over time. All pathways included in the 2020 IRP keep Duke Energy on a trajectory to meet its carbon goals over the 15-year planning horizon.

COMBINED CARBON REDUCTION BY SCENARIO



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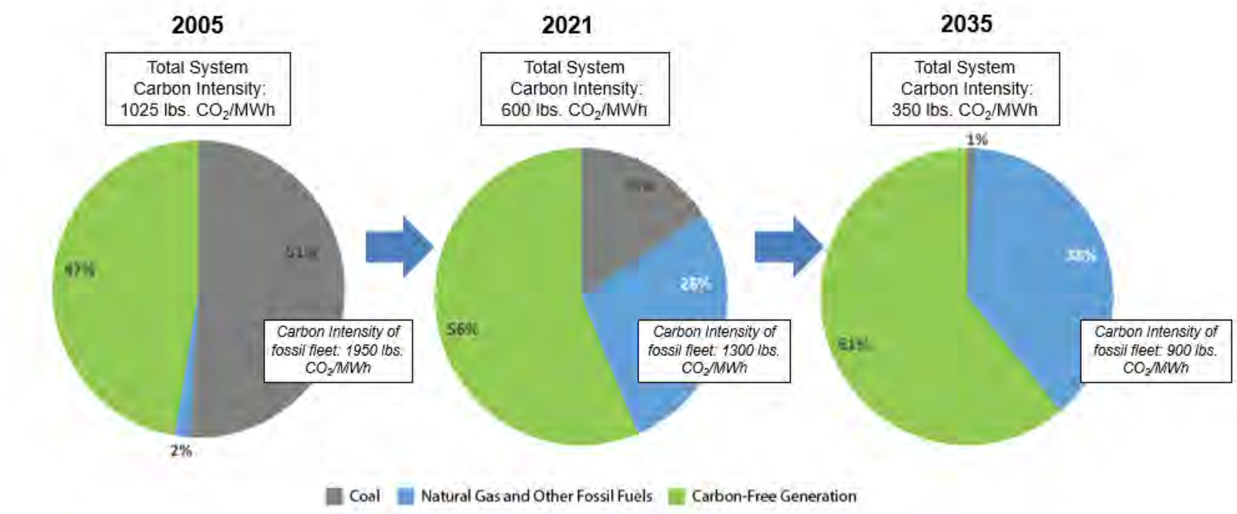
DEC has a strong historic commitment to carbon-free resources such as nuclear, hydro-electric and solar resources. In addition, as described in Appendix D, DEC provides customers with an expansive portfolio of energy efficiency and demand-side management program offerings. In total, DEC and Duke Energy Progress (DEP), through their Joint Dispatch Agreement (JDA), serve more than half of the energy needs of their customers with carbon free resources, making the region a national leader in carbon-free generation.

Combined, DEC and DEP operate six nuclear plants and 26 hydro-electric facilities in the Carolinas with winter capacities of over 11,000 MW and 3,400 MW respectively. In 2018, Duke Energy's nuclear fleet provided half of our customers' electricity in the Carolinas, avoiding the release of about 54 million tons of carbon dioxide, or equivalent to keeping more than 10 million passenger cars off the road. As the Company meets its customers' future energy needs and reduces its carbon footprint, it is seeking to renew the licenses of 11 nuclear units it operates at six plant sites in the Carolinas. This provides the option to operate these plants for an additional 20 years. In addition, DEC and DEP purchase or own approximately 4,000 MW of solar generation coming from approximately 1,000 solar facilities throughout the Carolinas. In DEC, where a large portion of energy has historically been sourced from carbon-free resources, the Company has reduced CO_2 emissions by 36% since 2005. In addition to a leadership position in absolute emission reductions, energy produced from the combined DEC/DEP fleet has one of the lowest carbon-intensities in the country. With a current CO_2 emissions rate of just over 600 pounds /megawatt-hour, the combined Carolinas' fleet ranks among the nation's top utilities for the provision of low carbon-intensive energy.[4] The following figure illustrates how the Company is building on its leadership position through the addition of carbon free resources such as solar and wind while also reducing the emissions profile and carbon intensity of remaining fossil generation by reducing dependence on coal and increasing utilization of more efficient, less carbon intense, natural gas resources.

[4] Source: MJ Bradley, "Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States" – July 2020, p. 30.

COMBINED SYSTEM CARBON REDUCTION TRAJECTORY (BASE CO_2)

THE COMBINED DEC / DEP FLEET IS A NATIONAL LEADER IN LOW CARBON INTENSITY ENERGY, WITH A CURRENT RATE 37% LOWER THAN THE INDUSTRY AVERAGE OF 957 LBS. CO_2/MWH[5]



STAKEHOLDER ENGAGEMENT

As part of the development of the 2020 IRP, Duke Energy actively engaged stakeholders in North Carolina and South Carolina with the objectives of listening, educating and soliciting input to inform the planning process. The Company initiated this engagement with local listening sessions followed by a series of virtual events which were facilitated by ICF,[6] and consisted of an IRP 101 education session and three stakeholder virtual forums, with over 200 participants from stakeholder groups involved across all activities. The forums included presentations and discussions from Duke Energy subject matter experts, and enabled discussion around the areas of greatest interest to stakeholders as identified through listening sessions, and pre- and post-engagement surveys. The sessions drew unique external stakeholder participants from across the Carolinas and provided recommendations in the areas of resource planning, carbon reduction, energy efficiency and demand response. Input from stakeholders helped shape the IRP development, and influenced the evaluation of different pathways

[5] Source: MJ Bradley, "Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States" – July 2020, p. 30.
[6] www.icf.com, ICF, an advisory and professional services company with a specialty in utility sector planning.

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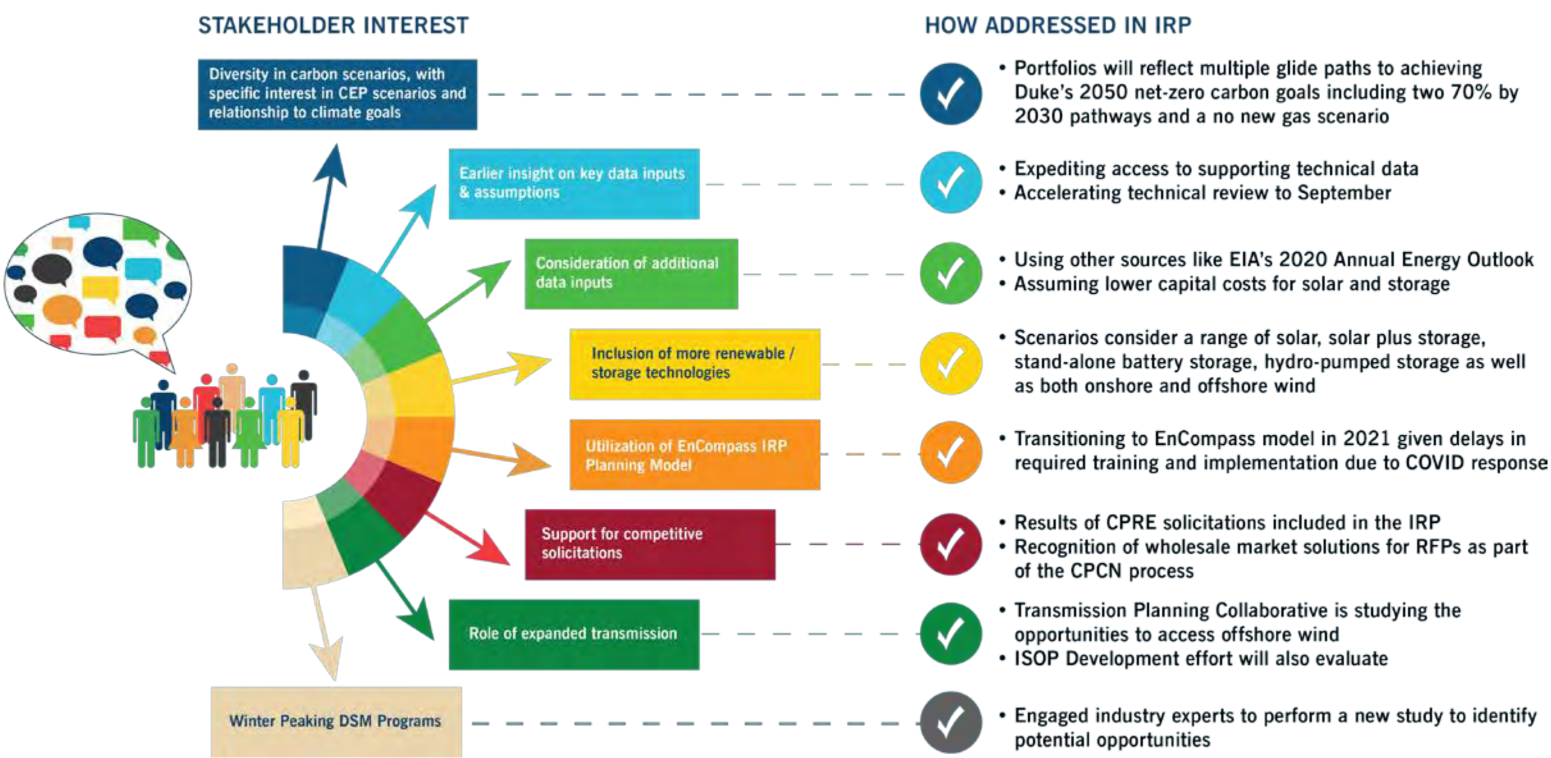
in the 2020 IRP. A summary report of these activities was developed by ICF and can be found on Duke Energy's web site.[7].



2020 IRP INFORMED BY NEW STUDIES, ILLUSTRATES MULTIPLE PATHWAYS

The 2020 IRP is informed by several new studies and analysis as well as collaboration and input from stakeholders. The analysis and studies in this IRP explore the opportunities and challenges over a range of options for achieving varying trajectories of carbon emission reduction. Specifically, the 2020 IRP highlights six possible portfolios, or plans, within the 15-year planning horizon. These portfolios explore the most economic and earliest practicable paths for coal retirement; acceleration of renewable technologies including solar, onshore and offshore wind; greater integration of battery and pumped-hydro energy storage; expanded energy efficiency and demand response and deployment of new zero-emitting load following resources (ZELFRs) such as small modular reactors (SMRs).

Consistent with regulatory requirements, the base case portfolios evaluate the need for the new resources associated with customer growth and the economic retirement of existing generation under

[7] www.duke-energy.com/irp.

a “no-carbon policy” view and a “with carbon policy” view respectively. These base case portfolios employ traditional least cost planning principles as prescribed in both North Carolina and South Carolina. The remaining plans build upon the carbon base case and were constructed with the assumption of future carbon policy. As described below, and in more detail in Appendix A, these six portfolios show different trajectories for carbon reduction with varying inputs such as coal retirement dates, types of resources and the level and pace of technology adoption rates, as well as contributions from energy efficiency and demand-side management initiatives. All six portfolios were evaluated under combinations of differing carbon and gas prices to test the impact these future scenarios would have on each plan. The results of that scenario analysis, including a table with retirement dates for each portfolio, are presented in Appendix A.

The portfolios also incorporate varying levels of demand-side management programs as an offset to future demand and energy growth. Stakeholders have voiced strong support for these initiatives and the Company has responded by including new conservation programs like Integrated Volt-Var Control (IVVC) which will further support the integration of renewables while also delivering peak and energy demand savings and enhanced reliability for our customers over time, and is further described in Appendix D. With input and support from stakeholders, the Company also undertook a new Winter Peak Shaving study with top consultants in this field. While more work is needed to develop and gain approval for new programs and complementary rate designs, this study provides an increased level of confidence that the high energy efficiency and demand response assumptions used in the portfolios with higher carbon reductions (D - F) could be realized with supportive regulatory policies in place.

The following table outlines the supportive studies used in development of this IRP. These studies cover an array of topical areas with perspective and analysis from some of the industry’s leading experts in their respective fields.

STUDY REQUIREMENTS

STUDY	STUDY REQUIREMENTS
Economic Coal Retirements	• Analysis established the most economic coal unit retirement dates for the Base CO_2 and Base No CO_2 scenarios.
Earliest Practicable Coal Retirements	• Analysis established the earliest feasible coal unit retirement dates. Analysis set aside normal economic considerations and focused on procurement and construction timelines for replacement capacity in order to retire the coal units at the earliest attainable dates.
Resource Adequacy Study/ Reserve Margin Study	• Astrapé Consulting study evaluated reliability based on meeting the one day in ten years loss of load expectation (LOLE) metric.
Storage Effective Load Carrying Capability (ELCC) Study	• Astrapé Consulting study evaluated capacity value of storage under multiple conditions, including its contribution to winter peak and considerations with increasing levels of renewable penetration.
Energy Efficiency and Market Potential Study	• Nexant study evaluated market potential for energy efficiency and demand response initiatives.
Winter Specific DR and Rate Design Benchmarking Study	• Being conducted by Tierra Resource Consultants, Proctor Engineering Group, and Dunsky. Studies the integration of new rate designs and DSM technology with innovative program structures to drive winter peak focused reductions.

GRID INVESTMENTS

Significant investment in the transmission and distribution system will be required to retire existing coal resources that support the grid and to integrate the incremental resources forecasted in this IRP. While grid investments are critical, ascribing precise cost estimates for individual technologies in the context of an IRP is challenging as grid investments depend on the type and location of the resources that are being added to the system. As described in Appendix A, if replacement generation with similar capabilities is not located at the site of the retiring coal facility, transmission investments will generally first be required to accommodate the unit's retirement in order to maintain regional grid stability. Furthermore, a range of additional transmission network upgrades will be required depending on the type and location of the replacement generation coming onto the grid. To that end, since the level of retirements and replacement resources vary by portfolio, separate estimates of

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potential required transmission investments are shown and are included in the present value revenue requirements (PVRR) for each of the portfolios. On a combined basis, the transmission investments described further in Chapter 7 have an approximate range of $1 billion in the Base Case portfolios to $9 billion in the No New Gas portfolio. The incremental transmission cost estimates are high level projections and could vary greatly depending on factors such as the precise location of resource additions, specific resource supply and demand characteristics, the amount of new resources being connected at each location, interconnection dependencies, escalation in labor and material costs, changes in interest rates and, potential siting and permitting delays beyond the Company's control. These also do not include the costs of infrastructure upgrades that would be needed on affected third party transmission systems, e.g., other utilities and regional transmission organizations.

With respect to the distribution grid, the Company is working to develop and implement necessary changes to the distribution system to improve resiliency and to allow for dynamic power flows associated with evolving customer trends such as increased penetration of rooftop solar, electric vehicle charging, home battery systems and other innovative customer programs and rate designs. Distribution grid control enhancement investments are foundational across the scenarios in this IRP, improving flexibility to accommodate increasing levels of distribution connected renewable resources while developing a more sustainable and efficient grid. In recognition of the critical role of the transmission and distribution system in an evolving energy landscape, the Company believes it will be critical to modernize the grid as outlined in Chapter 16 and to further develop its Integrated System & Operations Planning (ISOP) framework described in Chapter 15. The Company will use ISOP tools to identify and prioritize future grid investment opportunities that can combine benefits of advanced controls with innovative rate designs and customer programs to minimize total costs across distribution, transmission, and generation.

TECHNOLOGY, POLICY AND OPERATIONAL CONSIDERATIONS

As depicted further below, portfolios that seek quicker paces of carbon reductions have greater dependency on technology development, such as battery storage, small modular reactors and offshore wind generation, which are at varying levels of maturity and commercial availability[8]. As a result, these portfolios will have a greater dependence on technology advancements and projected future cost reductions, thus requiring near-term supportive energy policies at the state or Federal levels. For

[8] Source: Browning, Morgan S., Lenox, Carol S. "Contribution of offshore wind to the power grid: U.S. air quality. implications." *ScienceDirect,* 2020, https://www.sciencedirect.com/science/article/abs/pii/S0306261920309867.

example, future policy may serve to lower the cost of these emerging technologies to consumers through research and development funding or by providing direct tax incentives to these technologies.

As noted above, all portfolios will require additional grid investments in the transmission and distribution systems to integrate the new resources outlined in each of the portfolios. The portfolio analysis includes estimates of system costs, associated average residential monthly bill impact and operational and executional challenges for each portfolio. When considering these portfolios across both utilities, a combined look is presented below, followed by a DEC only view.

The "Dependency on Technology & Policy Advancement" row in the portfolio results table below reflects a qualitative assessment for each respective portfolio. More shading within a circle indicates a higher degree of dependence on future development of the respective technologies, supporting policy and operational protocols. The Base without Carbon Policy case reflects the current state, with little to no dependence on further technology advancements, policy development, and minimal operational risks. Working from left to right across the table, all other portfolios, including the Base with Carbon Policy case requires policy changes relative to the current state. The 70% CO_2 Reduction High Wind case would require supportive policies for expeditious onshore and offshore wind development and associated, necessary transmission build by 2030. The 70% CO_2 Reduction High SMR case was included to illustrate the importance of support for advancing these technologies as part of a balanced plan to achieve net-zero carbon. The No New Gas case includes dependence on all factors listed, as well as a much greater dependence on siting, permitting, interconnection and supply chain for battery storage. For the 70% reduction and No New Gas cases, the unprecedented levels of storage that are required to support significantly higher levels of variable energy resources present increased system risks, given that there is no utility experience for winter peaking utilities in the U.S. or abroad with operational protocols to manage this scale of dependence on short-term energy storage.

DEC / DEP COMBINED SYSTEM PORTFOLIO RESULTS TABLE

	Base without Carbon Policy		Base with Carbon Policy		Earliest Practicable Coal Retirements		70% CO_2 Reduction: High Wind		70% CO_2 Reduction: High SMR		No New Gas Generation	
PORTFOLIO	A		B		C		D		E		F	
System CO_2 Reduction (2030 | 2035)[1]	56%	53%	59%	62%	64%	64%	70%	73%	71%	74%	65%	73%
Present Value Revenue Requirement (PVRR) [$B][2]	$79.8		$82.5		$84.1		$100.5		$95.5		$108.1	
Estimated Transmission Investment Required [$B][3]	$0.9		$1.8		$1.3		$7.5		$3.1		$8.9	
Total Solar [MW][4, 5] by 2035	8,650		12,300		12,400		16,250		16,250		16,400	
Incremental Onshore Wind [MW][4] by 2035	0		750		1,350		2,850		2,850		3,150	
Incremental Offshore Wind [MW][4] by 2035	0		0		0		2,650		250		2,650	
Incremental SMR Capacity [MW][4] by 2035	0		0		0		0		1,350		700	
Incremental Storage [MW][4, 6] by 2035	1,050		2,200		2,200		4,400		4,400		7,400	
Incremental Gas [MW][4] by 2035	9,600		7,350		9,600		6,400		6,100		0	
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW][7] by 2035	2,050		2,050		2,050		3,350		3,350		3,350	
Remaining Dual Fuel Coal Capacity [MW][4, 8] by 2035	3,050		3,050		0		0		0		2,200	
Coal Retirements	Most Economic		Most Economic		Earliest Practicable		Earliest Practicable[9]		Earliest Practicable[9]		Most Economic[10]	
Dependency on Technology & Policy Advancement	○		◔		◑		◕		●		●	

[1]Combined DEC/DEP System CO_2 Reductions from 2005 baseline

[2]PVRRs exclude the cost of CO_2 as tax. Including CO_2 costs as tax would increase PVRRs by ~$11-$16B. The PVRRs were presented through 2050 to fairly evaluate the capital cost impact associated with differing service lives

[3]Represents an estimated nominal transmission investment; cost is included in PVRR calculation

[4]All capacities are Total/Incremental nameplate capacity within the IRP planning horizon

[5]Total solar nameplate capacity includes 3,925 MW connected in DEC and DEP combined as of year-end 2020 (projected)

[6]Includes 4-hr and 6-hr grid-tied storage, storage at solar plus storage sites, and pumped storage hydro

[7]Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour

[8]Remaining coal units are capable of co-firing on natural gas, all coal-only units that rely exclusively on coal are retired before 2030

[9]Earliest Practicable retirement dates with delaying one (1) Belews Creek unit and Roxboro 1&2 to EOY 2029 for integration of offshore wind/SMR by 2030

[10]Most Economic retirement dates with delaying Roxboro 1&2 to EOY 2029 for integration of offshore wind by 2030

LEGEND:

- ● Completely dependent
- ◕ Mostly dependent
- ◑ Moderately dependent
- ◔ Slightly dependent
- ○ Not dependent

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DEC PORTFOLIO RESULTS TABLE

	Base without Carbon Policy		Base with Carbon Policy		Earliest Practicable Coal Retirements		70% CO_2 Reduction: High Wind		70% CO_2 Reduction: High SMR		No New Gas Generation	
PORTFOLIO	A		B		C		D		E		F	
System CO_2 Reduction (2030 | 2035)[1]	56%	53%	59%	62%	64%	64%	70%	73%	71%	74%	65%	73%
Average Monthly Residential Bill Impact for a Household Using 1000kWh (by 2030 | by 2035)[2]	$7	$23	$8	$25	$13	$25	$26	$47	$24	$45	$12	$45
Average Annual Percentage Change in Residential Bills (through 2030 | through 2035)[2]	0.7%	1.3%	0.8%	1.5%	1.3%	1.4%	2.3%	2.5%	2.2%	2.5%	1.1%	2.4%
Present Value Revenue Requirement (PVRR) [$B][3]	$44.4		$46.8		$46.8		$56.1		$53.6		$56.0	
Estimated Transmission Investment Required [$B][4]	$0.6		$1.0		$0.7		$4.3		$2.1		$2.7	
Total Solar [MW][5, 6] by 2035	3,700		5,950		5,950		8,450		8,450		8,450	
Incremental Onshore Wind [MW][5] by 2035	0		150		0		1,100		1,100		1,400	
Incremental Offshore Wind [MW][5] by 2035	0		0		0		1,350		150		150	
Incremental SMR Capacity [MW][5] by 2035	0		0		0		0		700		700	
Incremental Storage [MW][5, 7] by 2035	350		600		600		2,400		2,400		2,400	
Incremental Gas [MW][5] by 2035	4,300		3,050		5,650		4,300		3,950		0	
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW][8] by 2035	1,225		1,225		1,225		1,850		1,850		1,850	
Remaining Dual Fuel Coal Capacity [MW][5, 9] by 2035	3,050		3,050		0		0		0		2,200	
Coal Retirements	Most Economic		Most Economic		Earliest Practicable		Earliest Practicable[10]		Earliest Practicable[10]		Most Economic	
Dependency on Technology & Policy Advancement	○		◔		◑		◕		●		●	

[1]Combined DEC/DEP System CO_2 Reductions from 2005 baseline

[2]Represents specific IRP portfolio's incremental costs included in IRP analysis; does not include complete costs for other initiatives that are constant throughout the IRP or that may be pending before state commissions

[3]PVRRs exclude the cost of CO_2 as tax. Including CO_2 costs as tax would increase PVRRs by ~$5-$8B. The PVRRs were presented through 2050 to fairly evaluate the capital cost impact associated with differing service lives

[4]Represents an estimated nominal transmission investment; cost is included in PVRR calculation

[5]All capacities are Total/Incremental nameplate capacity within the IRP planning horizon

[6]Total solar nameplate capacity includes 975 MW connected in DEC as of year-end 2020 (projected)

[7]Includes 4-hr and 6-hr grid-tied storage, storage at solar plus storage sites, and pumped storage hydro

[8]Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour

[9]Remaining coal units are capable of co-firing on natural gas, all coal-only units that rely exclusively on coal are retired before 2030

[10]Earliest Practicable retirement dates with delaying one (1) Belews Creek unit to EOY 2029 for integration of offshore wind/SMR by 2030

LEGEND:

- ● Completely dependent
- ◕ Mostly dependent
- ◑ Moderately dependent
- ◔ Slightly dependent
- ○ Not dependent

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CUSTOMER FINANCIAL IMPACTS

The Company is committed to the provision of affordable electricity for the residents, businesses, industries and communities served by DEC across its Carolinas' footprint. For each of the six portfolios analyzed, the IRP shows a high level projected present value of long-term revenue requirements and an average residential monthly bill impact across the Company's combined North and South Carolina service territory. Portfolios that have earlier and more aggressive adoption of technologies that are at earlier stages of development in the U.S., such as offshore wind or SMR generators, demonstrate or produce incrementally larger costs (revenue requirements) and bill impacts, but achieve carbon reductions at a more aggressive pace. While the IRP forecasts potential incremental system revenue requirement and system residential bill impact differences associated with each of the various scenarios analyzed in the IRP, it is recognized that these forecasts will change over time with evolving market conditions and policy mandates. Seeking the appropriate pace of technology adoption to achieve carbon reduction objectives requires balancing affordability while maintaining a reliable energy supply. The Company is actively engaged in soliciting stakeholder input into the planning process and is participating in the policy conversation to strike the proper balance in achieving progressive carbon reduction goals that align with customer expectations while also maintaining affordable and reliable service. Finally, cost and bill impacts presented are associated with incremental resource retirements, additions, and demand-side activities identified in the IRP and as such do not include potential efficiencies or costs in other parts of the business. Factors such as changing cost of capital, and changes in other costs will also influence future energy costs and will be incorporated in future IRP forecasts as market conditions evolve. Finally, future cost of service allocators and rate design will impact how these costs are spread among the customer classes and, therefore, customer bill impacts.

BASE CASES

The IRP reflects two base cases, each developed with a different assumption on carbon policy. The first case assumes no carbon policy, which is the current state today. Alternatively, the second base case assumes a policy that effectively puts a price on carbon emissions from power generation, with pricing generally in line with various past or current legislative initiatives, to incentivize lower carbon resource selection and dispatch decisions needed to support a trajectory to net-zero CO_2 emissions by 2050. Given the uncertainties associated with how a carbon policy may be designed, the 2020 IRP carbon policy includes a cost adder on carbon emissions in resource selection as well as daily operations, effectively a "shadow price" on CO_2 emissions. This "shadow price" is a generic proxy that could represent the effects of a carbon tax, price of emissions allowances, or a price signal needed to meet a given clean energy standard. Given the uncertainty of the ultimate form of policy, the cost and rate impacts shown only reflect the cost of the resources that would be required to achieve carbon reduction and not the "shadow price" itself. Customers could bear an additional cost if carbon policy takes the form of a carbon tax.

In accordance with regulatory requirements of both North Carolina and South Carolina, the base cases apply least cost planning principles when determining the optimal mix of resources to meet customer demand. It should be noted that even the Base Case without Carbon Policy includes results that more than double the amount of solar connected to the DEC and DEP system today. In addition, the Base Case without Carbon Policy includes approximately 1,000 MW of battery storage across the two utilities, which is slightly above the total amount in operation in the U.S. today (source: EIA[9]). The inclusion of a price on carbon emissions drives outcomes that include higher integration of solar, wind, and storage resources when compared to the case that excludes a carbon price. Both pathways utilize the most economic coal retirement date assumption, rather than relying on the depreciable lives of the coal assets as was the case in previous IRPs.

In the Company's base cases, across DEC and DEP combined, all units that operate exclusively on coal would be retired by 2030. The only remaining units that would continue to operate would be dual-fuel units with operation primarily on lower carbon natural gas. By 2035, 7,000 MW of coal-units representing 17% of nameplate capacity across the DEC and DEP system would retire, with the only remaining dual-fuel units of Cliffside 6 and Belews Creek 1 &2 operating through the remainder of their economic lives primarily on lower carbon natural gas. Under these base cases, DEP retires all 3,200 MW of coal capacity by 2030 and DEC retires approximately 3,800 MW of coal capacity by 2035. The remaining units can continue to provide valuable generation capacity to meet peak demand, with generation making up approximately less than 5% of the energy served by DEC and DEP combined by 2035.

The Company's investment to allow for use of lower carbon natural gas at certain coal sites provides a benefit to customers by optimizing existing infrastructure. This dual-fuel capability also improves operational flexibility to accommodate renewables by lowering minimum loads and improving ramp rates while also reducing carbon emissions over the remaining life of the assets. These base case

[9] https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf.

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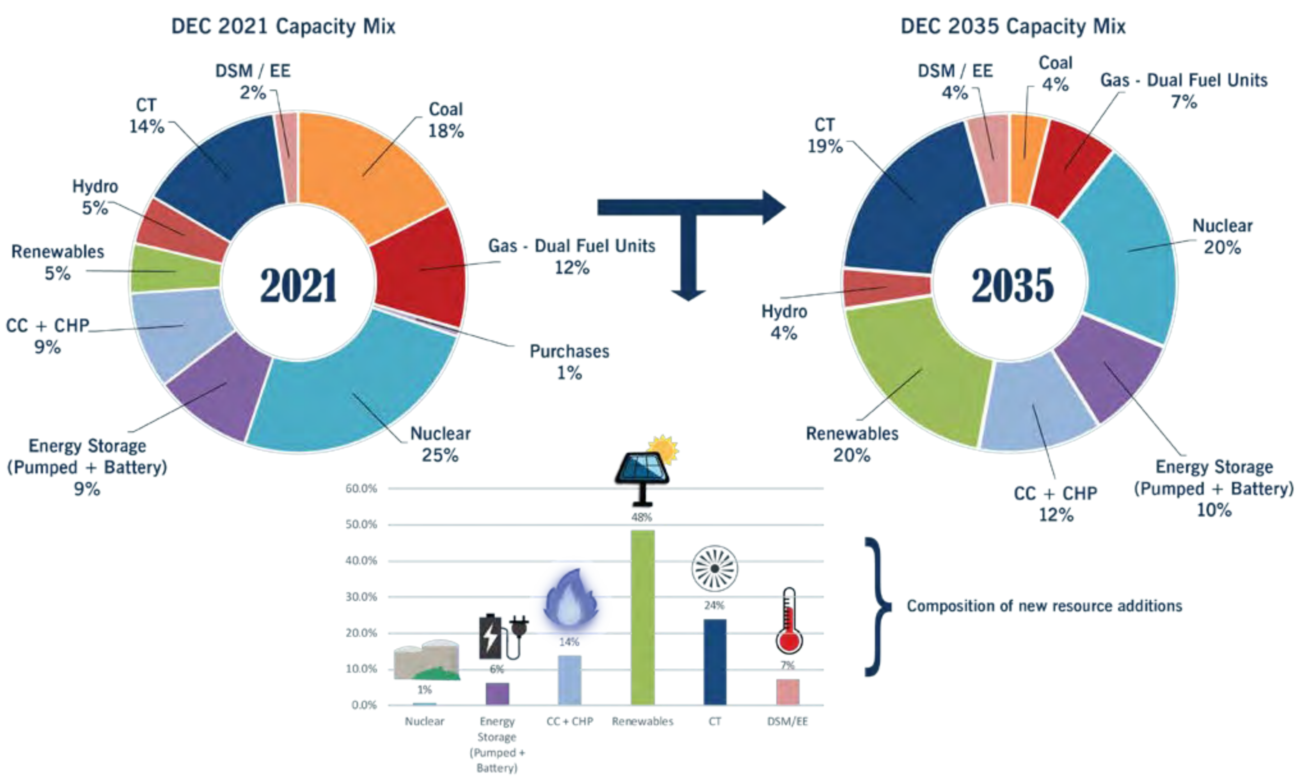
portfolios serve as the benchmark for comparing the incremental costs and benefits of alternative more aggressive carbon reduction scenarios. The figure below illustrates how DEC's capacity mix changes over the 2021 through the 2035 period in the Base Case with carbon policy. For example, renewables make up 48% of the incremental resources added between 2021 and 2035, raising the proportion of renewables in the overall fleet to 20% by 2035.

CHANGE IN INSTALLED CAPACITY[10]



EARLIEST PRACTICABLE COAL RETIREMENTS

For comparison purposes, the Earliest Practicable Retirement case suspends traditional "least cost" economic planning considerations and evaluates the physical feasibility of retiring all the Company's 10,000 MW of coal generation sites within DEC and DEP as early as practicable when taking into consideration the timing required to put replacement resources and supporting infrastructure into

[10] Change in capacity from the Base Case with Carbon Policy portfolio.

service. Aggressive levels of new solar, wind and battery storage were also utilized in this portfolio to accelerate the retirement of a portion of existing coal generation while also reducing the need for incremental gas infrastructure. In determining the “earliest practicable” coal retirement dates, this case considers the siting, permitting, regulatory approval and construction timeline for replacement resources as well as supporting infrastructure such as new transmission and new gas transportation infrastructure. This case assumes the majority of dispatchable resources are replaced at the coal retiring facilities to minimize the resources needed and time associated with additional land acquisition as well as transmission and gas infrastructure that would be required. This approach enables a more rapid transition from coal to lower carbon technologies while maintaining appropriate planning reserves for reliability.

Under this portfolio, all coal units in DEC and DEP would be retired by 2030 with the exception of DEC’s Cliffside 6 unit, which would take advantage of its current dual fuel capability and switch to 100% natural gas by 2030. In the aggregate across DEC and DEP, this portfolio includes a diverse mix of over 20,000 MW of new resources being placed in service. This diverse mix results in a combined system carbon reduction of 64% by 2030 while mitigating overall costs and bill impacts by leveraging existing infrastructure associated with the current coal fleet. Finally, while “practicable” from a technical perspective, the sheer magnitude, pace and array of technologies included in this portfolio with approximately half coming from renewable wind and solar resources and half from dispatchable gas, make it evident that new supportive energy policy and regulations would be required to effectuate such a rapid transition.

70% GHG REDUCTION CASES

This IRP also details two cases to achieve a more aggressive carbon reduction goal, such as the goal to achieve 70% greenhouse gas emission reductions from the electric sector by 2030, which is under evaluation in the development of the North Carolina Clean Energy Plan. Achieving these targets will require the addition of diverse, new types of carbon-free resources as well as additional energy storage to replace the significant level of energy and capacity currently supplied by coal units. To support this pace of carbon reduction, this case assumes the same coal unit retirement dates as the “earliest practicable” case, with the exception of shifting the retirement date of one of the Belews Creek units and Roxboro 1&2 units to the end of 2029 to allow for the integration of new carbon free resources by 2030. The resource portfolios in the 70% CO_2 reduction scenarios reflect an accelerated utilization of technologies that are yet to be commercially demonstrated at scale in the United States and may be challenging to bring into service by the 2030 timeframe.

For the purposes of this IRP, the Company evaluated the emerging carbon free technologies that are furthest along the development and deployment curves – Carolinas offshore wind and small modular nuclear reactors. Adding this level of new carbon free resources prior to 2030 will require the adoption of supportive state policies in both North Carolina and South Carolina. It will also require extensive additional analysis around the siting, permitting, interconnection, system upgrades, supply chain and operational considerations of more significant amounts of intermittent resources and much greater dependence on energy storage on the system. The High SMR case also assumes that SMRs are in service by 2030. However, the challenges with integrating a first of a kind technology in a relatively compressed timeframe are significant. Therefore, these cases are intended to illustrate the importance of advancing such technologies as part of a blended approach that considers a range of carbon-free technologies to allow deeper carbon reductions. When comparing and contrasting the two portfolios, differences in resource characteristics, projected future views on technology costs, associated transmission infrastructure requirements and dependencies on federal regulations and legislation all influence the pace and resource mix that is ultimately adopted in the Carolinas. An examination of two alternate portfolios that achieve 70% carbon reduction by 2030 highlight some of these key considerations for stakeholders. As discussed in Chapter 16, the Company is actively promoting the further development of future carbon free technologies which are a prerequisite to a net-zero future.

NO NEW GAS GENERATION

In response to stakeholder interest in a No New Gas case, the Company evaluated the characteristics of an energy system that excludes the addition of new gas generating units from the future portfolio. coal retirement dates reflected in the base case with the exception of Roxboro 1&2 which are delayed to the end of 2029 to allow for integration of offshore wind by 2030. Similar to the 70% CO_2 reduction cases, this resource portfolio is highly dependent upon the development of diverse, new carbon-free sources and even larger additions of energy storage and offshore wind as well as the adoption of supportive policies at the state and federal level. Also similar to the 70% case, the No New Gas case would require additional analysis around the siting, permitting, interconnection, system upgrades, supply chain integration and operational considerations of bringing on significant amounts of intermittent resources onto the system. Notably, the heavier reliance on large-scale battery energy storage in this scenario would require significant additional analysis and study since this technology is emergent with very limited history and limited scale of deployment on power grids worldwide. To provide a sense of scale, at the combined system level it would require approximately 1,100 acres of land, or more than 830 football fields to support the amount of batteries in this portfolio and would represent over six times the amount of large-scale battery storage currently in service in the United States. The lack of meaningful industry experience with battery storage resources at this scale presents significant operational considerations that would need to be resolved prior to deployment at such a large scale, which is addressed further in Chapter 16.

Finally, in the combined DEC and DEP view, the No New Gas case is estimated to have the highest customer cost impacts primarily due to the magnitude of early adoption of emerging carbon free technologies and the significant energy storage and transmission investments required to support those technologies. As is the case with almost all technologies, improvements in performance and reductions in cost are projected to occur over time. Without the deployment of new efficient natural gas resources as one component of a long-term decarbonization strategy, the system must run existing coal units longer to allow emerging technologies to evolve from both a technological and an economic perspective. In the alternative, the acceleration of coal retirements without some consideration of new efficient natural gas as a transition resource forces the large-scale adoption of such technologies before they have a chance to mature and decline in price, resulting in higher costs and operational risks for consumers. The summary table highlights the fact that this scenario is dependent on significant technological advances and new policy initiatives that would seek to recognize and address these considerations prior to implementation.

KEY ASSUMPTIONS

The following table provides an overview of the key assumptions applied to our modeling and analysis with comparisons to 2019 IRP. In addition, the company runs a number of sensitivities, such as high and low load growth, energy efficiency and renewable integration levels that demonstrate the impact of changes in various assumptions.

KEY ASSUMPTIONS TABLE

TOPIC AREA	2019 IRP	2020 IRP	NOTES
Load Forecast	**DEC:** 0.8% Winter Peak Demand CAGR **DEP:** 0.9% Winter Peak Demand CAGR	**DEC:** 0.6% Winter Peak Demand CAGR **DEP:** 0.9% Winter Peak Demand CAGR	Lower load growth due to economic factors and refinements of historical load data.
Reserve Margin	17%	17%	New LOLE Study reaffirms 17% strikes the appropriate balance between cost and reliability
Solar (Single Axis Tracking)	37% cost decline through 2030	42% cost decline through 2030	7% lower year one cost compared to 2019 IRP
4-hour Battery Storage	54% cost decline through 2030	49% cost decline through 2030	32% lower year one cost compared to 2019 IRP
Onshore Wind	12% cost decline through 2030	11% cost decline through 2030	7% lower year one cost compared to 2019 IRP; For the first time, wind allowed to be economically selected in planning process
Offshore Wind	N/A	40% cost decline through 2030	For the first time, offshore wind is considered in the planning horizon
Natural Gas	17% cost decline through 2030	17% cost decline through 2030	No Material Change
Coal	Retired based on depreciable lives at the time of the IRP	Retired based on analysis for most economic and earliest practicable retirement dates	Scenarios consider earliest practicable and most economic
New Nuclear	SMRs discussed but not screened for selection	SMRs included for selection	For the first time, SMRs available to be economically selected as a resource

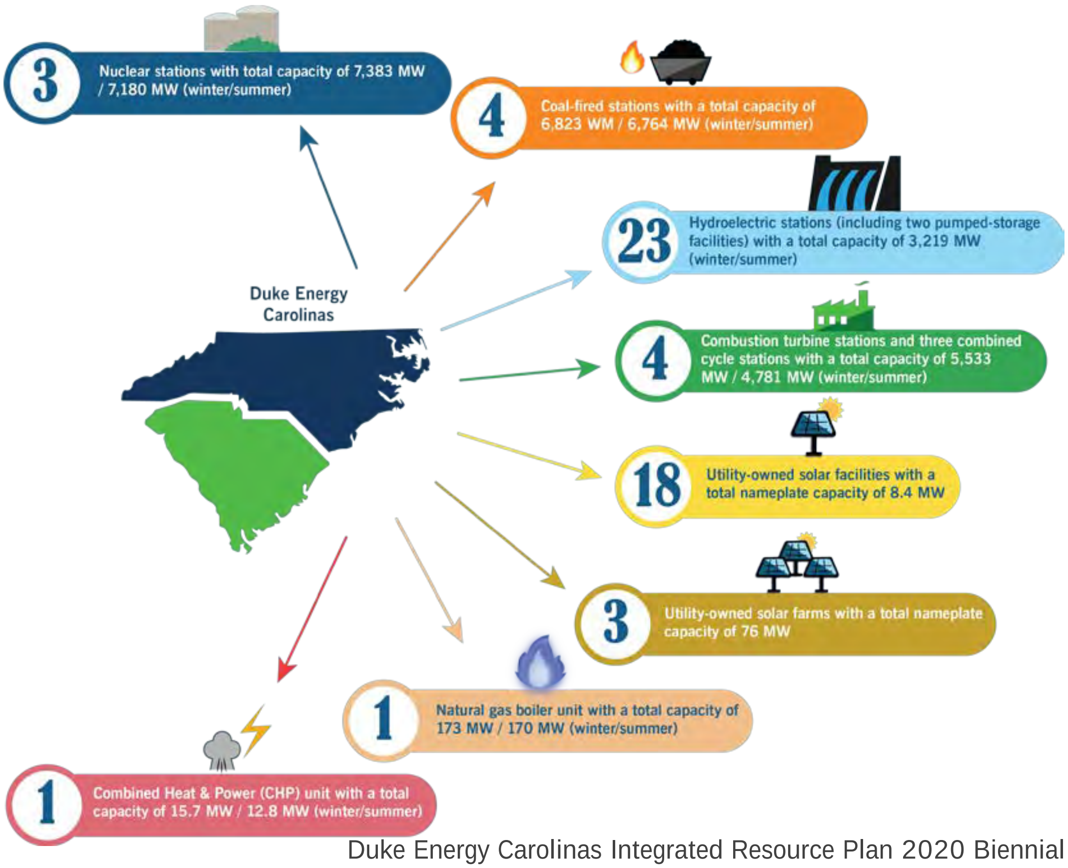
EXECUTIVE SUMMARY CONCLUSION

DEC remains focused on transitioning to a cleaner energy future, advancing climate goals that are important to its customers and stakeholders, while continuing to deliver affordable and reliable service. The 2020 IRP reflects multiple potential future pathways towards these goals. An analysis of each case reflects the associated benefits and costs with each portfolio as well as challenges that would need to be addressed with more aggressive carbon reduction scenarios. This range of portfolios helps illustrate the benefits of a diverse resource mix to assure the reliability of the system and efficiently support the transition toward a carbon-free resource mix. Public policies and the advancement of new, innovative technologies will ultimately shape the pace of the ongoing energy transformation. Duke Energy looks forward to continued engagement and collaboration with stakeholders to chart a path forward that balances affordability, reliability and sustainability.

2 SYSTEM OVERVIEW

DEC provides electric service to an approximately 24,090-square-mile service area in central and western North Carolina and western South Carolina. In addition to retail sales to approximately 2.67 million customers, the Company also sells wholesale electricity to incorporated municipalities and to public and private utilities. Recent historical values for the number of customers and sales of electricity by customer groupings may be found in Appendix C.

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



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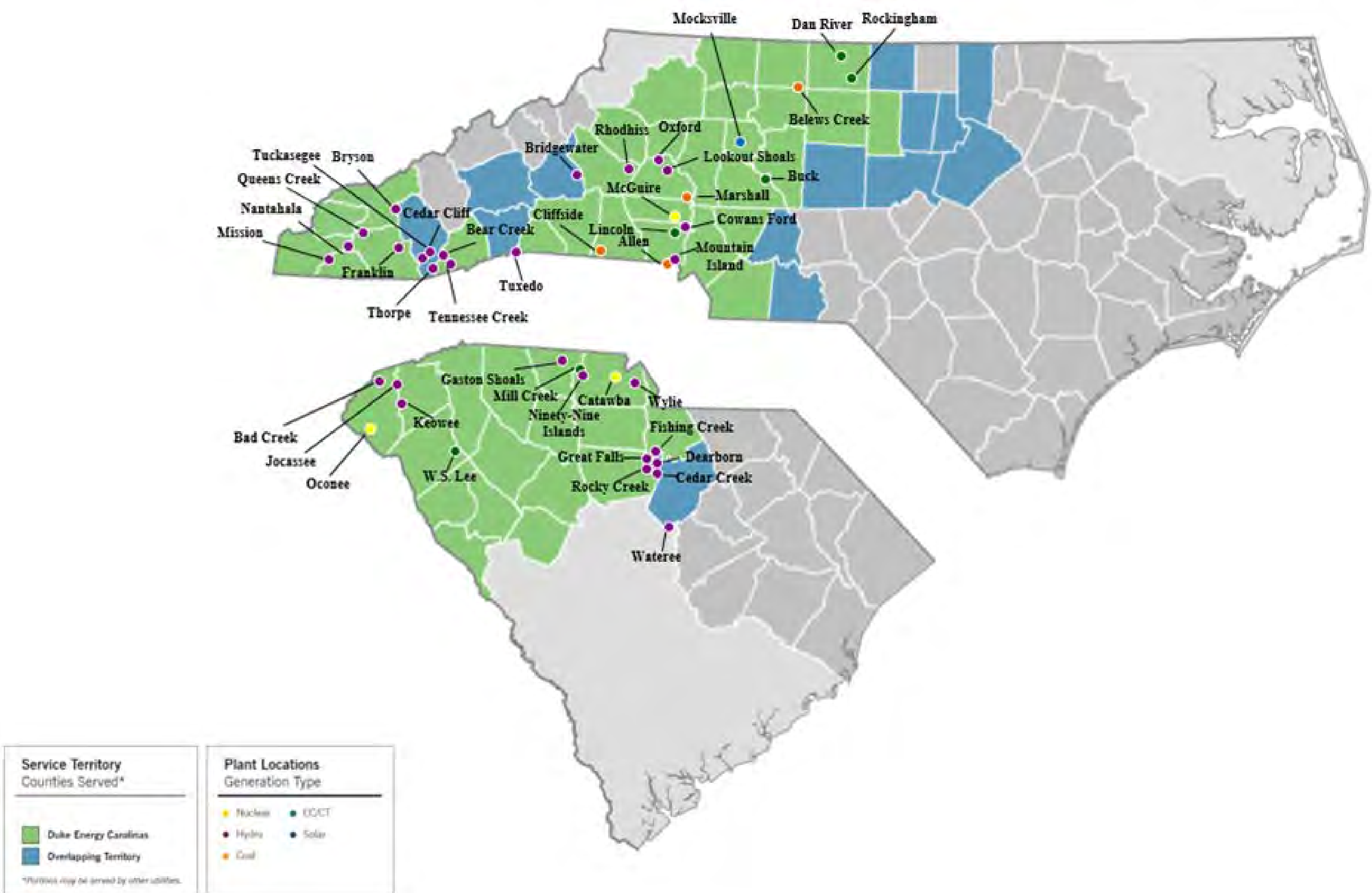
The Company's power delivery system consists of approximately 106,100 miles of distribution lines and 13,068 miles of transmission lines. The transmission system is directly connected to all the Transmission Operators that surround the DEC service territory. There are 35 tie-line circuits connecting with nine different Transmission Operators: DEP, PJM Interconnection, LLC (PJM), Tennessee Valley Authority (TVA), Smokey Mountain Transmission, Southern Company, Cube Hydro, Southeastern Power Administration (SEPA), Dominion Energy South Carolina (DESC) and Santee Cooper. These interconnections allow utilities to work together to provide an additional level of reliability. The strength of the system is also reinforced through coordination with other electric service providers in the Virginia-Carolinas (VACAR) sub-region, SERC Reliability Corporation (SERC) (formerly Southeastern Electric Reliability Council) and North American Electric Reliability Corporation (NERC).

The map on the following page provides a high-level view of the DEC service area with locations of the electric generation resources.

FIGURE 2-A

DUKE ENERGY CAROLINAS SERVICE AREA



The service territories for both DEC and DEP lend to future opportunities for collaboration and potential sharing of capacity to create additional savings for North Carolina and South Carolina customers of both utilities. An illustration of the service territories of the Companies are shown in the map below.

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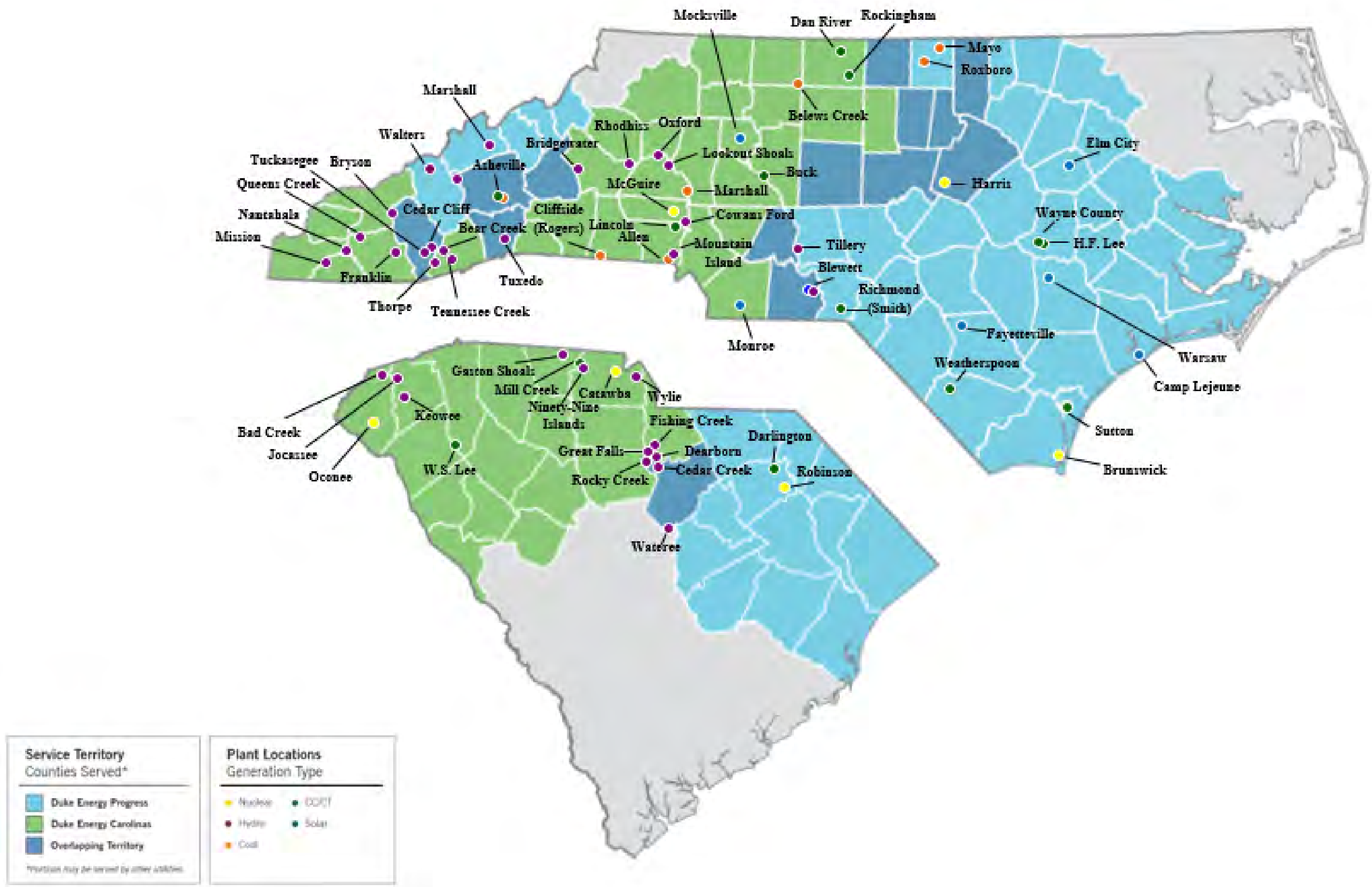
FIGURE 2-B

DEC AND DEP SERVICE AREA



3 ELECTRIC LOAD FORECAST

The Duke Energy Carolinas' Spring 2020 forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2021-2035 and represents the needs of the following customer classes:

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

The Residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electricity prices and appliance efficiencies. The average annual growth rate of Residential energy sales in the Spring 2020 forecast, including the impacts of Utility Energy Efficiency programs (UEE), rooftop solar and electric vehicles from 2021-2035 is 1.0%.

The three largest sectors in the Commercial class are offices, education and retail. The Commercial forecast also uses an SAE model to reflect naturally occurring as well as government mandated efficiency changes. Commercial energy sales are expected to grow 0.5% per year over the forecast horizon. The Industrial class is forecasted by a standard econometric model, with drivers such as total manufacturing output and the price of electricity. Overall, Industrial sales are expected to decline 0.2% per year over the forecast horizon.

The Company continues to look at ways to improve the load forecasting methodology in order to develop the most accurate and reasonable demand forecasts for DEC. The 2020 load forecast update is lower compared to the 2019 IRP. The decrease in the 2020 update is primarily driven by refinements to peak history, the addition of 2019 peak history and declines in Commercial and Industrial energy sales. The 2020 update also includes revised projections for rooftop solar and electric vehicle programs and the impacts of voltage control programs. The key economic drivers and forecast changes are shown below in Tables 3-A and 3-B. A more detailed discussion of the load forecast can be found in Appendix C.

TABLE 3-A
KEY DRIVERS

	2021-2035
Real Income	2.9%
Manufacturing Industrial Production Index (IPI)	1.1%
Population	1.5%

Table 3-B reflects a comparison between the 2020 and 2019 growth rates of the load forecast with and without impacts of EE.

TABLE 3-B

2020 DEC LOAD FORECAST GROWTH RATES VS. 2019 LOAD FORECAST GROWTH RATES (INCLUSIVE OF RETAIL AND WHOLESALE LOAD)

	2020 FORECAST (2021-2035)			2019 FORECAST (2020-2034)		
	Summer Peak Demand	Winter Peak Demand	Energy	Summer Peak Demand	Winter Peak Demand	Energy
Excludes impact of new EE programs	0.9%	0.7%	0.7%	1.2%	1.0%	1.1%
Includes impact of new EE programs	0.8%	0.6%	0.5%	1.0%	0.8%	0.9%

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4 ENERGY EFFICIENCY, DEMAND-SIDE MANAGEMENT AND VOLTAGE OPTIMIZATION

DEC is committed to making sure electricity remains available, reliable and affordable and that it is produced in an environmentally sound manner and, therefore, DEC advocates a balanced solution to meeting future energy needs in the Carolinas. That balance includes a strong commitment to energy efficiency (EE) and demand-side management (DSM).

Since 2009, DEC has been actively developing and implementing new EE and DSM programs throughout its North Carolina and South Carolina service areas to help customers reduce their electricity demands. DEC's EE and DSM plan is designed to be flexible, with programs being evaluated on an ongoing basis so that program refinements and budget adjustments can be made in a timely fashion to maximize benefits and cost-effectiveness. Initiatives are aimed at helping all customer classes and market segments use energy more wisely. The potential for new technologies and new delivery options is also reviewed on an ongoing basis in order to provide customers with access to a comprehensive and current portfolio of programs.

DEC's EE programs encourage customers to save electricity by installing high efficiency measures and/or changing the way they use their existing electrical equipment. DEC evaluates the cost-effectiveness of EE/DSM programs from the perspective of program participants, non-participants, all customers, and total utility spending using the four California Standard Practice tests (i.e., Participant Test, Rate Impact Measure (RIM) Test, Total Resource Cost (TRC) Test and Utility Cost Test (UCT), respectively) to ensure the programs can be provided at a lower cost than building supply-side alternatives. The use of multiple tests can ensure the development of a reasonable set of programs and indicate the likelihood that customers will participate. DEC will continue to seek approval from

State utility commissions to implement EE and DSM programs that are cost-effective and consistent with DEC's forecasted resource needs over the planning horizon. DEC currently has approval from the North Carolina Utilities Commission (NCUC) and Public Service Commission of South Carolina (PSCSC) to offer a large variety of EE and DSM programs and measures to help reduce electricity consumption across all types of customers and end-uses.

For IRP purposes, these EE-based demand and energy savings are treated as a reduction to the load forecast, which also serves to reduce the associated need to build new supply-side generation, transmission and distribution facilities. DEC also offers a variety of DSM (or demand response) programs that signal customers to reduce electricity use during select peak hours as specified by the Company. The IRP treats these "dispatchable" types of programs as resource options that can be dispatched to meet system capacity needs during periods of peak demand.

In 2019, DEC commissioned an EE market potential study to obtain estimates of the technical, economic and achievable potential for EE savings within the DEC service area. The analysis to develop the market potential study included three distinct scenarios: a Base scenario using the baseline input assumptions, an Enhanced scenario which considered the impact of increased program spending to attract new customers, and an Avoided Energy Cost Sensitivity where higher future energy prices result in increased economic and achievable EE savings potential.

The final report was prepared by Nexant, Inc. and was completed in June 2020. The results of the market potential study are suitable for integrated resource planning purposes and use in long-range system planning models. However, the study did not attempt to closely forecast short-term EE achievements from year to year. Therefore, the EE/DSM savings contained in this IRP were projected by blending DEC's five-year program planning forecast into the long-term achievable potential projections from the market potential study.

DEC prepared a Base EE Portfolio savings projection that was based on DEC's five-year program plan for 2020-2024. For periods beyond 2029, the Base Portfolio assumed that the Company could achieve the annual savings projected in the Base Achievable Portfolio presented in Nexant's Market Potential Study. For the period of 2025 through 2029, the Company employed an interpolation methodology to blend together the projection from DEC's program plan and the Market Potential Study Achievable Potential.

DEC also prepared a High EE Portfolio savings projection based on the Enhanced and Avoided Energy Cost Sensitivity Scenarios contained in Nexant's Market Potential Study. The High EE savings forecast was developed using a similar process to the Base case, however; for the Nexant MPS portion of the forecast, the difference between the Avoided Energy Cost Sensitivity and Base Scenarios for all years was added to the Enhanced Case forecast. This method captures the higher EE savings potential resulting from both the higher avoided energy cost assumptions as well as from increased incentives in the Enhanced case.

Finally, a Low EE Portfolio savings projection was developed by applying a reduction factor to the Base EE Portfolio forecast. Additionally, for the Base, High and Low Portfolios described above, DEC included an assumption that, when the EE measures included in the forecast reach the end of their useful lives, the impacts associated with these measures are removed from the future projected EE impacts. This concept of "rolling off" the impacts from EE programs is explained further in Appendix C.

In addition to the updated MPS and consistent with feedback from stakeholders, the Company undertook a detailed study to specifically examine the potential for additional winter demand-side peak savings through innovative rates initiatives combined with advanced demand response and load shifting programs that were outside of the MPS scope. To develop this targeted demand response study the Company engaged Tierra Resource Consultants who collaborated with Dunsky Energy Consulting and Proctor Engineering. These firms represent three of the industry's leading practitioners in the development and deployment of innovative energy efficiency and demand response programs across North America. The Company envisions working with stakeholders in the upcoming months and beyond to investigate and deploy, subject to regulatory approval, additional cost-effective programs identified through this effort. At the time of this writing preliminary results from this study show promise for additional winter peak demand savings that could move the Company closer to the high energy efficiency and demand response sensitivity identified in the IRP. While it is premature to include such findings in the Base Case forecast, the results do show a potential pathway for moving closer to the High Case identified in the IRP. Over time as new programs/rate designs are approved and become established, the Company will gain additional insights into customer participation rates and peak savings potential and will reflect such findings in future forecasts.

Lastly, Integrated Voltage/VAR Control (IVVC) is part of the proposed Duke Energy Carolinas Grid Improvement Plan (GIP) and involves the coordinated control of distribution equipment in substations and on distribution lines to optimize voltages and power factors on the distribution grid. If the GIP is approved for DEC, the rollout of IVVC is anticipated to take approximately four years and will be deployed on 50% of the total circuits and substations across the service territory, accounting for approximately 70% of current base load.

See Appendix D for further detail on DEC's EE, DSM and consumer education programs, which also includes a discussion of the methodology for determining the cost effectiveness of EE and DSM programs. A complete writeup and detailed implementation schedule on the IVVC program is included, as well.

5 RENEWABLE ENERGY STRATEGY / FORECAST

The growth of renewable generation in the United States continued in 2019. According to EIA, in 2019, 9.1 GW of wind and 5.3 GW of utility-scale solar capacity were installed nationwide. The EIA also estimates 3.7 GW of small scale solar was added as well.[1] Notably, U.S. annual energy consumption from renewable sources exceeded coal consumption for the first time since before 1885.[2]

North Carolina ranked sixth in the country in solar capacity added,and first in additions of solar plants greater than 2 MW, in 2019 and remains second behind only California in total solar capacity online, while South Carolina ranked seventh in solar capacity added in 2019.[3] [4] Duke Energy's compliance with the North Carolina Renewable Energy and Energy Efficiency Portfolio Standards (NC REPS), the South Carolina Distributed Energy Resource Program (SC DER or SC Act 236), the Public Utility Regulatory Policies Act (PURPA) as well as the availability of the Federal Investment Tax Credit (ITC) were key factors behind the high investment in solar.

RENEWABLE ENERGY OUTLOOK FOR DUKE ENERGY IN THE CAROLINAS

The future is bright for opportunities for continued renewable energy development in the Carolinas as

[1] All renewable energy GW/MW represent GW/MW-AC (alternating current) unless otherwise noted.
[2] https://www.eia.gov/todayinenergy/detail.php?id=43895.
[3] https://www.seia.org/states-map.
[4]https://www.eia.gov/electricity/data/eia860M/; February month end data

both states have supportive policy frameworks and above average renewable resource availability, particularly for solar. The Carolinas also benefits from substantial local expertise in developing and interconnecting large scale solar projects and the region will benefit from such a concentration of skilled workers. Both states are supporting future renewable energy development via two landmark pieces of legislation, HB 589 in North Carolina (2017) and Act 62 in South Carolina (2019). These provide opportunities for increased renewable energy, particularly for utility customer programs for both large and small customers who want renewable energy. These programs have the potential to add significant renewable capacity that will be additive to the historic reliance on administratively-established standard offer procurement under PURPA in the Carolinas. Furthermore, the Companies' pending request to implement Queue Reform—a transition from a serial study interconnection process to a cluster study process—will create a more efficient and predictable path to interconnection for viable projects, including those that are identified through any current or future procurement structures. It is also worth noting that that there are solar projects that appear to be moving forward with 5-year administratively-established fixed price PURPA contracts and additional solar projects that will likely be completed as part of the transition under Queue Reform.

SUMMARY OF EXPECTED RENEWABLE RESOURCE CAPACITY ADDITIONS

DRIVERS FOR INCREASING RENEWABLES IN DEC

The implementation of NC HB 589, and the passage of SC Act 62 in SC are significant to the amount of solar projected to be operational during the planning horizon. Growing customer demand, the Federal ITC, and declining installed solar costs continue to make solar capacity the Company's primary renewable energy resource in the 2020 IRP. However, achieving the Company's goal of net-zero carbon emissions by 2050 will require a diverse mix of renewable, and other zero-emitting, load following resources. Wind generation, whether onshore wind generated in the Carolinas or wheeled in from other regions of the country, or offshore wind generated off the coast of the Carolinas, may become a viable contributor to the Company's resource mix over the planning horizon.

The following key input assumptions regarding renewable energy were included in the 2020 IRP:

- Through existing legislation such as NC HB589 and opportunities under SC Act 62, along with materialization of existing projects in the distribution and transmission interconnection queues, installed solar capacity increases in DEC from 966 MW in 2021 to 3,493 MW in 2035 with approximately 185 MW of usable AC storage coupled with solar included prior to incremental solar added economically during the planning process.

- Additional solar and solar coupled with storage was available to be selected by the capacity expansion model to provide economic energy and capacity. Consistent with recent trends, total annual solar and solar coupled with storage interconnections were limited to 300 MW per year over the planning horizon in DEC.

- Up to 150 MW of onshore Carolinas wind generation, assumed to be located in the central Carolinas, could be selected by the capacity expansion model annually to provide a diverse source of economic energy and capacity.

- Compliance with NC REPS continues to be met through a combination of solar, other renewables, EE, and Renewable Energy Certificate (REC) purchases.

- Achievement of the SC Act 236 goal of 160 MW of solar capacity located in DEC.

- Implementation of NC HB 589 and SC Act 62 and continuing solar cost declines drive solar capacity growth above and beyond NC REPS requirements.

For more details regarding these assumptions, along with more information about NC HB 589 and SC Act 62, see Appendix E.

BASE WITH CARBON POLICY

The 2020 IRP Base with Carbon Policy case incorporates the projected and economically selected renewable capacities shown below. The projected renewables in this case includes renewable capacity components of the Transition MW, such as capacity required for compliance with NC REPS, PURPA purchases, the SC DER Program, NC Green Source Rider (pre HB 589 program), and the additional three components of NC HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). The Base with Carbon Policy case also includes additional projected solar growth beyond NC HB 589, including potential growth from SC Act 62 and the materialization of additional projects in the transmission and distribution queues. This case does not attempt to project future regulatory requirements for additional solar generation, such as new competitive procurement offerings after the current CPRE program expires.

However, it is the Company's belief that continued declines in the installation cost of solar and storage will enable solar and coupled "solar plus storage" systems to contribute to energy and/or capacity needs. Additionally, the inclusion of a CO_2 emissions tax, or some other carbon emissions reduction policy, would further incentivize expansion of solar resources in the Carolinas. In the Base with Carbon Policy case, the capacity expansion model selected additional solar averaging approximately 100 MW per year beginning in 2025 and solar coupled with storage averaging approximately 120 MW annually beginning in 2028 if a CO_2 tax were implemented in the 2025 timeframe.

In addition to solar generation, wind energy is expected to play an important role in providing a diverse source of generation in the Carolinas. While previous IRPs have contemplated wind generation as a potential resource, for the first time, the 2020 IRP includes wind generation located in the central Carolinas as a technically viable source of carbon free energy and capacity. Though capacity factors of wind generation located in this region are much lower than other onshore or offshore regions, central Carolinas wind benefits from significantly lower transmission costs while still providing a diverse source of carbon free generation. The materialization of wind in the Carolinas is dependent on resolving historic barriers to siting and permitting; but, because the Company views wind as a potentially viable resource and an important step in meeting its carbon reduction goals, central Carolinas wind was included as a resource in the capacity expansion modeling process. With the inclusion of a CO_2 tax beginning in 2025, 150 MW of wind generation was selected annually beginning in the 2034 timeframe.

In addition to onshore wind, the Company is also evaluating offshore wind as a potential energy resource in the short and long term to support increased renewable portfolio diversity, an important resource for achieving the Company's 2050 net-zero carbon emission goal, as well as long-term general compliance need. The 70% CO_2 Reduction: High Wind and No New Gas Generation portfolios both include over 2,400 MW of offshore wind imported into the Carolinas. The challenges with accessing this potential resource are described further in Appendix E.

The Company anticipates a diverse renewable portfolio including solar, biomass, hydro, storage fed by solar, wind and other resources. Actual results could vary substantially for the reasons discussed in Appendix E. The details of the forecasted capacity additions, including both nameplate and contribution to winter and summer peaks are summarized in Table 5-A below.

TABLE 5-A

DEC BASE WITH CARBON POLICY TOTAL RENEWABLES

DEC BASE RENEWABLES - COMPLIANCE + NON-COMPLIANCE															
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL
2021	966	0	132	0	1,099	387	0	132	0	519	10	0	132	0	142
2022	1,327	115	118	0	1,560	514	70	118	0	702	13	29	118	0	160
2023	1,673	134	81	0	1,888	636	81	81	0	797	17	34	81	0	131
2024	1,976	163	81	0	2,219	741	99	81	0	921	20	41	81	0	141
2025	2,268	192	59	0	2,519	844	116	59	0	1,019	23	48	59	0	129
2026	2,519	211	49	0	2,778	930	127	49	0	1,106	25	53	49	0	127
2027	2,708	335	49	0	3,091	977	202	49	0	1,228	27	84	49	0	160
2028	2,895	458	42	0	3,395	1,024	274	42	0	1,340	29	114	42	0	185
2029	3,082	656	42	0	3,779	1,071	390	42	0	1,502	31	164	42	0	236
2030	3,217	802	38	0	4,058	1,104	475	38	0	1,618	32	201	38	0	271
2031	3,352	948	30	0	4,330	1,138	559	30	0	1,727	34	237	30	0	301
2032	3,486	1,094	12	0	4,592	1,171	642	12	0	1,826	35	273	12	0	321
2033	3,620	1,238	3	0	4,861	1,205	724	3	0	1,932	36	310	3	0	349
2034	3,753	1,382	0	0	5,135	1,230	803	0	0	2,032	37	345	0	0	383
2035	3,885	1,525	0	150	5,560	1,242	875	0	11	2,127	38	381	0	50	469

Corrected 11.06.2020

As a number of solar contracts are expected to expire over the IRP planning period, the Company is additionally breaking down its solar forecast into three buckets described below:

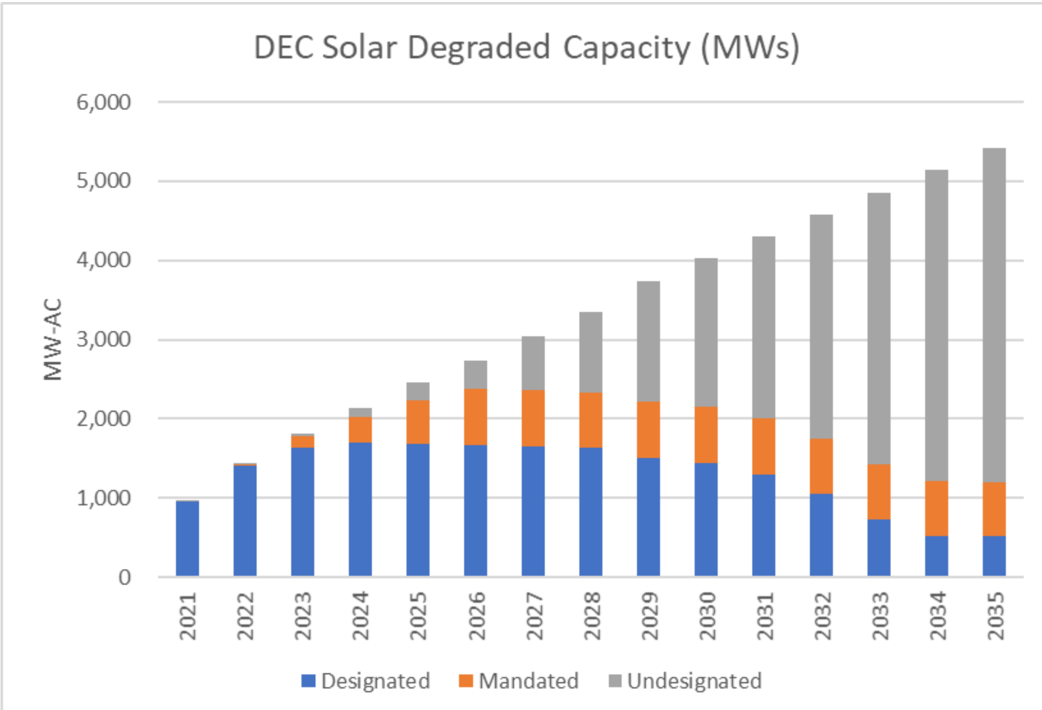
- **Designated**: Contracts that are already connected today or those who have yet to connect but have an executed PPA are assumed to be designated for the duration of the purchase power contract.

- **Mandated**: Capacity that is not yet under contract but is required through legislation (examples include future tranches of CPRE, the renewables energy procurement program for large customers, and community solar under NC HB 589 as well as SC Act 236).

- **Undesignated**: Additional capacity projected beyond what is already designated or mandated. Expiring solar contracts are assumed to be replaced in kind with undesignated solar additions. Such additions may include existing facilities or new facilities that enter into contracts that have not yet been executed.

The figure below shows DEC's breakdown of these three buckets through the planning period. Note for avoided cost purposes, the Company only includes the Designated and Mandated buckets in the base case.

FIGURE 5-A
DEC SOLAR DEGRADED CAPACITY (MW)



In addition to these base case additions, the Company also developed high and low renewable investment sensitivities that are discussed in Appendix E.

6 ENERGY STORAGE AND ELECTRIC VEHICLES

As part of DEC's broader efforts to modernize the grid, the Company is strategically developing and deploying battery storage projects at locations where it can deliver maximum value for customers and surrounding communities. Battery storage is capable of both storing and dispatching energy at strategic times to provide a variety of benefits for customers as well as the grid. Utility dispatch and operation of battery syste ms is typically accomplished in fractions of a second, which is critical to manage the continued growth of intermittent resources (e.g. solar and wind) connected to the grid. The versatility of battery storage enables these facilities to be a natural extension of the grid and the Company will continue to apply its engineering and operational expertise to integrate this important technology into its regular planning and grid management functions.

Battery storage costs are declining rapidly which allows the Company to consider the technology as a viable option for grid services, as described in the 2018 IRP, including ancillary services (e.g. frequency regulation, voltage, and ramping support), energy and capacity, renewable smoothing, T&D deferral, and backup power. Operational benefits are gained from improved efficiencies, flexibility, and reliability – in some cases enabling the Company to defer future grid investments that would otherwise be required. The Company is also working with its customers who require enhanced resiliency and energy security as they provide critical services to the community (e.g. hospitals, first responders, emergency shelters and the military).

While there are various types of storage technologies, in the near term, the Company plans to deploy megawatt-scale electrochemical batteries and continues to partner with diverse suppliers who can provide the latest battery technology expertise and resources. The Company is ensuring compliance with evolving regulations and standards related to safety, reliability, and cybersecurity. Furthermore, the Company consults with leading fire protection engineers to guide the design process, includes multiple layers and levels of safety systems in each of its batteries, and actively engages and trains first responders and 911 reporting centers.

In DEC's 2018 IRP, the Company included 150 MW of nameplate battery storage, representing grid connected projects that have the potential to provide benefits to the generation, transmission, and distribution systems. These 150 MW of nameplate battery storage are also included in this 2020 IRP. Additionally, as discussed in greater detail in Appendix A, the Company sees a growing need for energy storage later in the planning horizon. Meanwhile, DEC continues to analyze other opportunities to utilize battery storage systems, including customer-sited projects and combining battery storage with new or existing PV facilities.

For over a decade, Duke Energy has been piloting emerging battery storage technologies at several sites in the Carolinas. For example, the McAlpine Substation Energy Storage and Microgrid Project in Charlotte, N.C. was commissioned in late 2012. An existing 200-kW BYD lithium iron phosphate battery and a newly installed 30-kW Eos battery is interconnected with a 50-kW solar facility. The batteries provide energy shifting and solar smoothing applications when grid connected and maintain power to a fire station during a grid outage event. At Duke Energy's state-of-the-art research center in Mount Holly, N.C., the Company continues to collaborate with vendors, utilities, research labs and government agencies to develop and commercialize an interoperability framework that enables the integration of distributed resources and demonstrates alternative approaches for microgrid operations.

LONG-TERM OUTLOOK

As solar and other intermittent generation increases on DEC's system, and the cost of battery storage technologies fall, the need for, and value of, additional storage will continue to grow. As shown in Phase 1 of NREL's Integration of Carbon Free Resources Study, storage can play an important role in reducing curtailment of solar resources on DEC's system as the penetration of solar energy expands. However, in DEC, given the availability of 2,140 MW of pumped hydro storage and the projected penetration of renewable energy on the system, battery storage shows less value than Combustion Turbine peaking units in the Base with Carbon Policy portfolio. Importantly, this outcome will be revisited periodically as future projections for battery storage costs evolve. Currently the Company forecasts an approximate 50% decline in battery storage costs by 2030 understanding that the actual pace of technological advancements, or even future potential policy mandates that influence storage costs, may change this forecast in future IRPs.

Additionally, the projected steep cost declines of battery storage add some risk to early adoption of this technology. The benefits gained from storage helping to integrate more renewables quicker or potentially replacing retiring generation sooner can likely be captured a few years later at a lower cost to customers. In the Base with Carbon Policy Case, storage coupled with solar is first economically selected in the 2028 timeframe when prices are projected to be more than 40% lower than current estimates.

As is the case with all energy-limited resources, as the penetration of short-term duration storage increases, the incremental benefit of that resource diminishes. To investigate how quickly this loss of value could occur, the Company commissioned Astrapé Consulting, a nationally recognized expert in the field, to conduct a detailed Capacity Value of Battery Storage study that is included as an attachment to the DEC IRP and is discussed in greater detail in Appendix H. This study assessed the contribution to winter peak capacity of varying levels and durations of both standalone battery storage and battery storage paired with solar resources under increasing levels of solar integration. As shown in Figure 6-A, both four and six-hour batteries maintain an average capacity value above 80% to 90% of rated power capacity up to 1,600 MW of penetration on the DEC system. Conversely, the average capacity value of two-hour batteries falls below 80% prior to 800 MW of penetration. This drop is even more dramatic when considering the incremental value of battery storage shown in Figure 6-B. While the first 400 MW of two-hour batteries on the system provide approximately 85% to meeting winter peak capacity needs, the next 400 MW only provide approximately 65%. Two-hour storage generally performs the same function as DSM programs that, not only reduce winter peak demand, but also tend to flatten demand by shifting energy from the peak hour to hours just beyond the peak. This flattening of peak demand is one of the main drivers for rapid degradation in capacity value of 2-hours storage. As the Company seeks to expand winter DSM programs, the value of two-hour storage will likely diminish, and for these reasons, DEC only considered four and six-hour battery storage in the IRP.

FIGURE 6-A

AVERAGE CAPACITY VALUE OF TWO, FOUR, AND SIX HOUR STORAGE

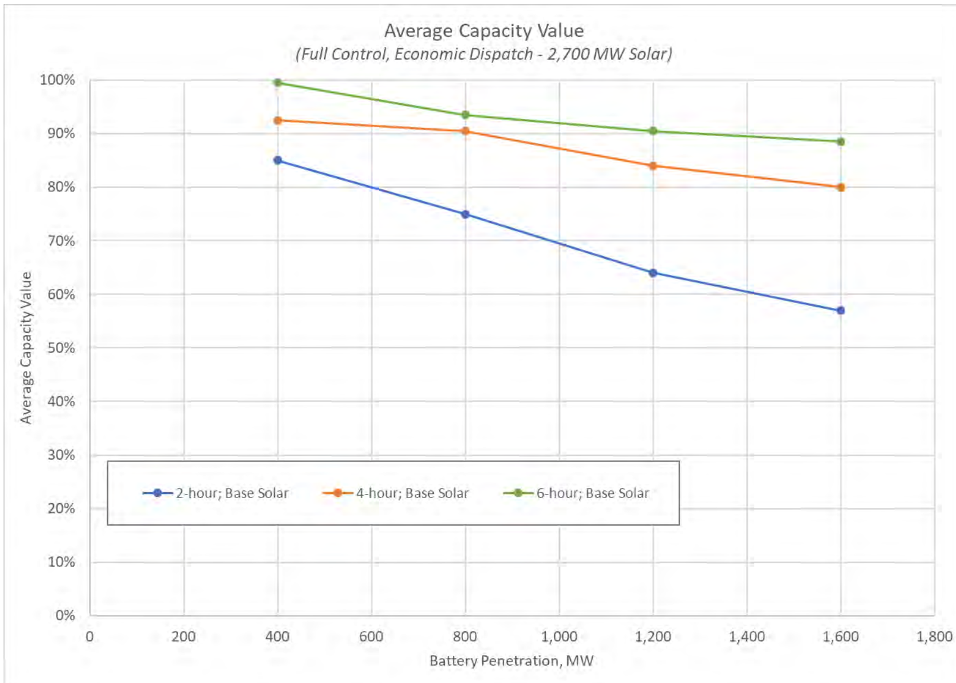


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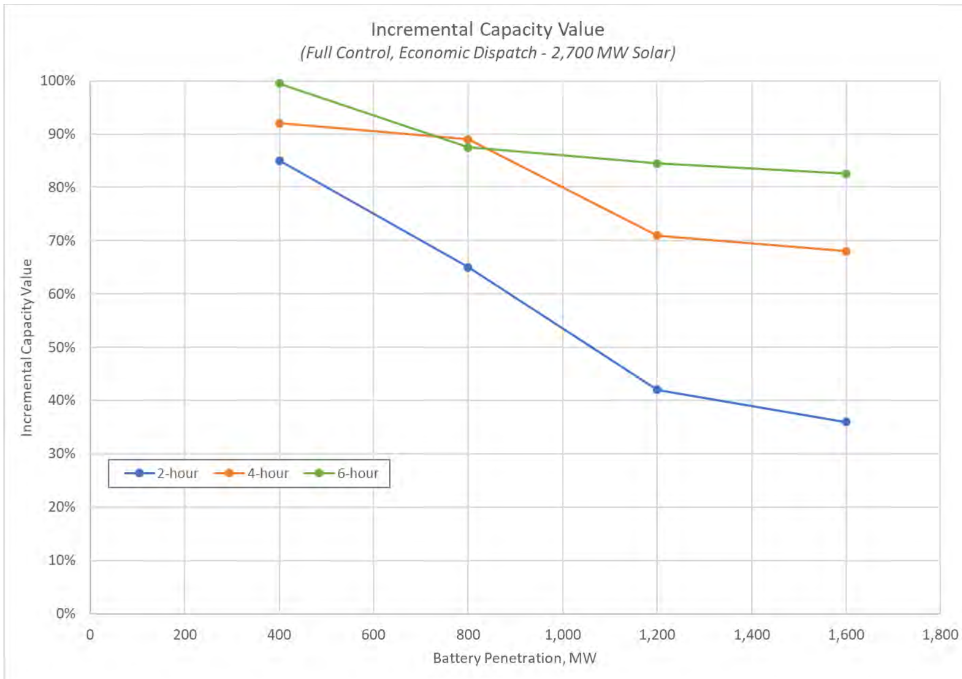
FIGURE 6-B

INCREMENTAL CAPACITY VALUE OF TWO, FOUR, AND SIX HOUR STORAGE[1]



The Capacity Value of Storage study also evaluated the capacity value of solar coupled with storage under multiple solar penetrations and with increasing ratios of storage to solar capacity. In this analysis, the battery storage could only be charged from the solar asset it was coupled with, and the solar plus storage maximum output was limited to the capacity of the solar asset. The capacity value of a solar plus storage facility is represented as the percent of solar nameplate capacity, so if a 100 MW solar facility coupled with a 25 MW / 100 MWh battery has a capacity value of 25% the MW contribution to winter peak is 25 MW.

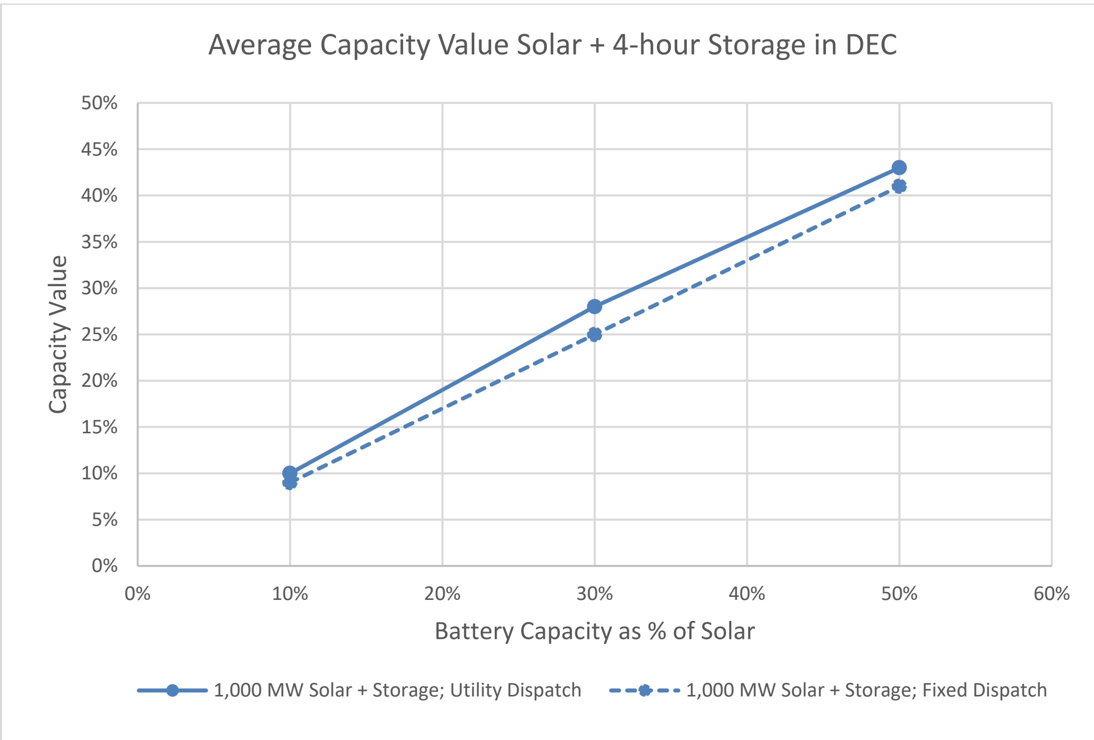
One factor that can impact the capacity value of storage is the level of control the Utility maintains over dispatching the battery. A solar plus storage PURPA QF, may charge and discharge the battery to a fixed, long-term contract with static price signals. Conversely, if the Utility has control over dispatch of the battery, the likelihood that the battery will be available to provide capacity when it is needed is

[1] Incremental values are calculated based on the average capacity value for 400 MW increments of battery storage. Due to rounding, calculated incremental values may appear higher or lower than the actual incremental value.

increased. Figure 6-C shows capacity value of the solar plus storage facility can be decreased by 5% to 11% if the storage is dispatched on a fixed price schedule rather than under Utility control.

FIGURE 6-C

AVERAGE CAPACITY VALUE OF SOLAR PLUS STORAGE FACILITY UNDER UTILITY CONTROL VS FIXED DISPATCH SCHEDULE



In addition to the discussion of the Battery ELCC study, Appendix H also includes a discussion of the terminology and operating characteristics of battery storage technologies. There is frequently confusion when discussing the duration, capacity, energy losses, modeling assumptions and costs of battery storage. The "Battery Storage Assumptions" section of Appendix H was developed in order to increase transparency related to Duke's assumptions associated with battery storage in the 2020 IRP.

ELECTRIC VEHICLES

Another important form of energy storage is electric vehicles. Electrification is expected to play an important role in the reduction of carbon dioxide emissions across all sectors of the economy. Electric vehicles (EVs) in particular are poised to transform and decarbonize the transportation industry which accounts for 28% of US carbon dioxide emissions, more than any other economic sector[2].

EVs also offer financial benefits for consumers and for the electric grid. EV drivers save money on fuel and maintenance costs, and the purchase of a new EV can be offset by up to $7,500 with the Qualified Plug-In Electric Drive Motor Vehicle Tax Credit. Increasing EV growth can create benefits for all utility customers by increasing utilization of the electric grid and putting downward pressure on rates.

Duke Energy receives monthly updates on light-duty vehicle registrations from the Electric Power Research Institute (EPRI). Registrations are tracked by county and attributed to DEC based on the size of its customer count in each county. Reporting and analysis focus on plug-in electric vehicles (PEVs) which are charged from the electric grid. Conventional vehicles and hybrid EVs are also tracked to provide context for PEV growth within the total vehicle market.

According to EPRI 2,700 new PEVs were registered in 2019, and 10,600 PEVs were in operation by the end of the year. Most of those vehicles were adopted in NC which had 9,100 PEVs in operation compared to 1,600 in SC. Annual registrations increased from 2018 to 2019 by a small margin. The modest growth was partly due to an outsized increase in 2018 (+130%) driven by the popular Tesla Model 3 sedan.

On October 29, 2018, NC Governor Cooper issued Executive Order 80, in which he directed the State of NC to "strive to accomplish" increasing the number of registered, zero-emission vehicles to at least 80,000 by 2025. In order to adequately respond to state policies like Executive Order 80, and considering the significant pace of EV adoption in its service territories, Duke Energy recognizes that it must prepare for and better understand the electrical needs and impacts of EVs on its systems. As insufficient charging infrastructure is commonly cited as a barrier to EV adoption[3], Duke Energy believes that more investment in EV charging infrastructure will accelerate EV adoption, consistent with the intent of state policies and the fast-developing EV market. To that end, Duke Energy conducted an analysis to demonstrate the potential electric system/customer benefits of increased EV adoption, and the potential for utility-managed charging to enhance those benefits.

[2] U.S. EPA's Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2018

[3] Edison Electric Institute: Accelerating EV Adoption Report (February 2018).
https://www.eei.org/issuesandpolicy/electrictransportation/Documents/Accelerating_EV_Adoption_final_Feb2018.pdf

Duke Energy designed and proposed electric transportation (ET) pilots in NC and SC to determine best practices for realizing the significant potential benefits of increased ET adoption, including the long-term potential for downward rate pressure, retaining fuel cost savings in the states, reducing vehicle emissions and improving air quality. The ET pilots would span three years and comprise a series of programs that address three areas of concern: EV charging management on the grid, transit electrification and public charging expansion. For EV charging management, Duke Energy proposed a residential EV charging infrastructure rebate and a fleet EV charging infrastructure rebate. For transit electrification, Duke Energy proposed an EV school bus charging program and an EV transit bus charging program for both North and South Carolina, including a Vehicle-to-Grid research component for the EV school bus program. For public charging expansion, Duke Energy proposed a multi-family dwelling charging station program, a public level 2 charging station program and a direct current fast charging station program to establish a baseline network of charging infrastructure across the states.

TABLE 6-A

PROPOSED CAROLINAS ELECTRIC TRANSPORTATION PILOT PROGRAMS

PROGRAM COMPONENT	UNITS (NORTH CAROLINA)	UNITS (SOUTH CAROLINA)
Residential Charging	800	400
Fleet Charging	900	NA
Transit Bus Charging	105	30
School Bus Charging	85	15
Public Level 2/Multi-Family	480	NA
Public DC Fast Charging	120	60

Duke Energy is also partnering with EPRI to study the market potential for non-road EVs and to develop strategies to promote electrification in the commercial and industrial sectors. Commercial and non-road EVs are expected to have a significant impact on the electric grid due to their high utilization rates and high energy demand. Deployment of these technologies, and their impact on the grid, may scale up quickly when companies with large commercial and non-road vehicle fleets transition to EVs. One early example is Amazon's order of 100,000 electric delivery vans from Rivian, expected to be deployed over 2021-2030.

7 GRID REQUIREMENTS

The purpose of this chapter is to describe the development of initial estimates for costs associated with the retirement of coal generating units and siting of replacement generation for the six key portfolios outlined in the Executive Summary and Appendix A.

Retiring existing coal facilities that support the grid and integrating incremental resources forecasted in this IRP will require significant investment in the transmission and distribution systems. As described in Chapter 11 and Appendix A, if replacement generation that can provide similar ancillary service as well as real power needs is not located at the site of the retiring coal facility, transmission investments will generally be required to accommodate the unit's retirement in order to maintain regional grid stability. Furthermore, a range of additional transmission network upgrades will be required depending on the type and location of the replacement generation coming onto the grid. To avoid overstating these Grid upgrade costs, the Company took the approach of assuming resources would be interconnected at the transmission level. In general, connecting generators at the transmission level does not require distribution upgrades, whereas connecting generators at the distribution level can require upgrades to transmission.

With respect to the distribution grid, the Company is working with policy makers and stakeholders to develop and implement necessary changes to the distribution system to improve resiliency and to allow for dynamic power flows associated with evolving customer trends such as increased penetration of rooftop solar, electric vehicle charging, home battery systems and other innovative customer programs. Distribution investments that enable increased levels of distributed energy resources are foundational across the scenarios in this IRP and provide flexibility to accommodate the dynamic power flows resulting from a changing customer service needs and distributed energy resource landscape. In recognition of the critical role of the transmission and distribution system in an evolving energy landscape, the Company sees significant value in modernizing the distribution portion of the grid as outlined in Chapter 16 and to further develop its Integrated System Optimization and Planning (ISOP) framework described in Chapter 15.

DEC FUTURE TRANSMISSION PROJECTS REQUIRED TO FACILITATE CARBON REDUCTION TARGETS

The six portfolios presented in this IRP included different assumptions for coal plant retirement dates along with a varying array of demand and supply-side resource requirements to reliably serve load over the planning horizon. The Company conducted high-level assessments to estimate the associated necessary transmission network upgrades for retiring the existing coal facilities and integrating each scenario's requisite incremental resources, including combinations of some or all of the following resources: solar, solar-plus-storage hybrid facilities, stand-alone battery storage, pumped-hydro generation/storage, onshore wind, offshore wind, increased off-system purchases, and dispatchable natural gas facilities. These assessments were conducted at a high level utilizing several reasonable, simplifying assumptions. To the extent possible, the Company used recent interconnection studies as a basis for future costs. Extensive additional study and analysis of the complex interactions regarding future resource planning decisions will be needed over time to better quantify the cost of transmission system upgrades associated with any portfolio.

As noted in Appendix L, location, MW interconnection requested, resource/load characteristics, and prior queued requests, in aggregate can have wide ranging impacts on transmission network upgrades required to approve the interconnection request for a new resource and the associated costs. Also, the actual costs for the associated network upgrades are dependent on escalating labor and materials costs. Based on recent realized cost from implementing transmission projects, the escalation of labor, materials, environmental, siting and permitting costs in future years could be significant. In addition to risks associated with costs, to facilitate meeting necessary deadlines for placing new transmission lines and substations in service, policies and approvals for siting and permitting will need to allow for expediting and streamlining associated processes. The timing and nature of these future projects will also be dependent on any neighboring system upgrades needed.

With the significant volume of interconnection requests in the future indicated by the six portfolios described in this IRP, the proposed clustering process associated with queue reform, if approved, will help from a planning studies perspective. The increase in volume of interconnection requests however, unlike the small volume of interconnection requests for traditional larger size generators, will make studying such requests and assigning necessary upgrades quite complex. The complexity and uncertainty of planning for high volumes of DERs, compared to planning for conventional generation that has known capacity and locations with a planning and construction timeline similar to that of the associated transmission upgrades, is much greater for the following reasons:

- The number of permutations of resource types, locations, timing, capacity within resource scenarios and between scenarios can be significant.
- A large volume of both distribution and transmission connected generation and battery storage resources that are in un-sited locations, are of unknown capacity, and have unspecified and variable production profiles, make modeling these resource scenarios very complex.

Given the long lead times for planning, siting, permitting and construction of new transmission, there is some risk that some of the projects represented in the estimates below could not be completed in time to support the in-service dates contemplated by the more aggressive scenarios (C-F).

The resources required to reliably serve load under each portfolio impacts the Company's existing transmission system. Every portfolio requires upgrades to the Duke Energy transmission system, some substantial, and some would require substantial transmission upgrades to other third parties' transmission systems interconnected to Duke Energy's transmission grid. This section outlines high level assessments of the transmission infrastructure required for each portfolio and the estimated costs of that transmission infracture[1]. This section does not attempt to estimate the projects that would be required on third party transmission systems, nor does the Company estimate these third-party costs.

Importantly, the transmission costs for each portfolio and sensitivity presented in this IRP were not calculated directly in each individual case. For instance, transmission costs associated with retiring coal assets were estimated by evaluating the impact of retiring each plant individually without

[1] The cost estimates provided are high-level and not yet at a Class 5 level. As such, the cost estimates could vary greatly depending upon, among other factors, ultimate corridor and resource location, MW interconnection requested, resource/load characteristics, interconnection queue changes, escalation in construction labor and materials costs, siting and permitting, interest rates, cost of capital, and schedule delays beyond the Company's control. In addition, the actual costs for the associated network upgrades are dependent on escalating labor and materials costs. Based on recent realized cost from implementing transmission projects, the escalation of labor and materials costs in future years could be significant.

replacement on site. These estimates were calculated based on information as was known at the time the analysis was conducted and without regard for any particular portfolio. In this manner, in any portfolio where the coal asset was not replaced on site, the transmission cost associated with that plant retirement was assumed to be the same. Furthermore, any new generation added to, or generation removed from, the DEC system in the analysis may significantly impact these cost estimates and therefore, these costs will need to be re-evaluated at the time the decision to retire these assets is made.

Additionally, the cost of integrating increasing levels of distributed and other resources was based on three portfolios:

- Base with Carbon Policy
- 70% CO_2 Reduction: High Wind
- No New Gas Generation

The transmission cost estimates from these portfolios were used as the basis for calculating the transmission costs in all other portfolios and sensitivities discussed in this document. As an example, if the cost to integrate the first 2,000 MW of solar on the DEC system was $100M based on the Base with Carbon Policy, that same cost was assumed to be the cost for integrating the first 2,000 MW of solar in all portfolios and sensitivities. These three specific portfolios were chosen because they represent a broad range of the types of technologies found in all portfolios.

The following are the transmission cost estimates, in overnight 2020 dollars, that were used as a reference in the development of the PVRR values shown later in Appendix A.

DEC FUTURE TRANSMISSION PROJECTS TO FACILITATE RETIREMENT OF EXISTING DEC COAL FACILITIES

The high-level assessment conducted to determine the transmission network upgrades needed to enable the retirement of the DEC coal facilities without replacing generation on site was estimated to be:

- Marshall 1-4: $200 M
- Belews Creek 1&2: $230 M

Cliffside 5 currently does not require transmission upgrades to enable retirement, and Cliffside 6 was assumed to operate on 100% natural gas and was not evaluated for retirement over the planning horizon. Transmission projects to enable a potential Allen retirement are progressing and are not shown as an expense in the IRP analysis.

DEC FUTURE TRANSMISSION PROJECTS TO FACILITATE THE BASE WITH CARBON POLICY PORTFOLIO

The high-level assessment conducted to determine the transmission network upgrades needed to enable the interconnection of new resources for the Base with Carbon Policy portfolio resulted in an estimate of approximately $560M for DEC transmission network upgrades.

DEC FUTURE TRANSMISSION PROJECTS TO FACILITATE THE 70% CO_2 REDUCTION: HIGH WIND PORTFOLIO

The high-level assessment conducted to determine the transmission network upgrades needed to enable the interconnection of new resources for the 70% CO_2 Reduction: High Wind portfolio resulted in an estimate of approximately $1.7B for DEC transmission network upgrades. Estimates for transmission network upgrades to import offshore wind energy were based on prior North Carolina Transmission Planning Collaborative (NCTPC) assessments. An update of these NCTPC assessments are in progress and may result in materially different network upgrade costs.

DEC FUTURE TRANSMISSION PROJECTS TO FACILITATE THE NO NEW GAS GENERATION PORTFOLIO

The high-level assessment conducted to determine transmission network upgrades needed to enable the interconnection of new resources for the No New Gas Generation portfolio resulted in an estimate of approximately $1.9B for DEC transmission network upgrades. This assessment assumes that SMRs can be selectively located at retired coal plant or other brownfield sites. Other locations requested for interconnection could result in necessary network upgrades and significant increased costs. Additionally, DEP imports approximately 2,400 MW of offshore wind in this portfolio. It is likely that to integrate offshore wind energy into the Carolinas; statewide policies would be required, and the transmission infrastructure costs to move the energy from the coast to load centers could be spread across all customers regardless of their legacy transmission provider.

DEC/DEP AREA FUTURE TRANSMISSION PROJECTS TO FACILITATE INCREASED IMPORT CAPABILITY

In addition to the estimates shown above, the Company conducted a high-level evaluation of increasing import capability into the DEC and DEP area transmission systems. Based on prior experience and similar transmission interface projects, it is expected that such third-party transmission costs would be substantial; particularly under scenarios where 5 to 10 GWs of power is imported into the DEC/DEP area transmission systems. Additional analysis would be needed to further refine the transmission projects and costs, however these preliminary assessments indicate that extensive incremental Transmission investment would be required if existing generation were retired and replaced with generation outside of the Company's area transmission systems.

The Company conducted a high-level assessment to identify the number of transmission projects and estimated costs associated with increasing import capability into the DEC/DEP area transmission systems from all neighboring transmission regions as well as from offshore wind. The assessments considered the necessary new construction and upgrades needed to increase import capability by 5GW and 10GW respectively.

The 5GW import scenario would require on the DEC/DEP transmission systems alone:

- four (4) new 500kV lines,
- three (3) new 230kV lines,
- two (2) new 500/230kV substations,
- four (4) 300 MVAR SVCs, and
- several reconductor and lower class voltage upgrades.

The estimated costs for the associated transmission projects is between \$4B and \$5B.

The 10GW import scenario would require on the DEC/DEP transmission systems alone:

- seven (7) new 500kV lines,
- four (4) new 230kV lines,
- three (3) new 500/230kV substations,
- four (4) 300 MVAR SVCs, and
- several reconductor and lower class voltage upgrades.

The estimated costs for the associated transmission projects is between $8B and $10B.

Importantly, actual upgrade costs may vary significantly when the specific projects to enable the requested incremental import capability need are identified through detailed Transmission Planning studies. Equally significant, these estimates exclude the cost of neighboring third-parties' transmission system upgrades, which would be dependent on items, including, but not limited to, the location of the capacity resource being purchased, the MW level of the capacity being purchased, the position in the queue of competing transmission service requests, and the performance of third parties to complete such projects on schedule and on budget.

The system risks with relying on significant incremental import capability for future resource plan needs include, but are not limited to:

a. Delay in resource availability – if required transmission network upgrades on the DEC/DEP transmission system or neighboring transmission systems are delayed due to sitting, permitting, or construction issues, these delays can jeopardize the scheduled in-service date of the transmission upgrades necessary for importing the capacity resource.

b. Loss of local ancillary benefits that are inherent with an on-system resource (e.g. Voltage/Reactive Support, Inertia/Frequency Response, AGC/Regulation for balancing renewable output) may require more on-system transmission upgrades such as adding SVCs for voltage support.

c. Curtailment due to transmission constraints in neighboring areas.

d. Transmission system stability issues under certain scenarios due to added distance between the capacity resource and load.

8 SCREENING OF GENERATION ALTERNATIVES

As previously discussed, the Company develops the load forecast and adjusts for the impacts of EE programs that have been pre-screened for cost-effectiveness. The growth in this adjusted load forecast and associated reserve requirements, along with existing unit retirements or purchased power contract expirations, creates a need for future generation. This need is partially met with DSM resources and the renewable resources required for compliance with NC REPS, HB 589, and SC Act 236. The remainder of the future generation needs can be met with a variety of potential supply side technologies.

For purposes of the 2020 IRP the Company considered a diverse range of technology choices utilizing a variety of different fuels, including Combustion Turbines (CTs), Reciprocating Engines, Combined Cycles (CCs) with and without duct firing, Ultra-Supercritical Pulverized Coal (USCPC) with Carbon Capture and Sequestration (CCS), Integrated Gasification Combined Cycle (IGCC) with CCS, Nuclear, and Combined Heat and Power (CHP). In addition, Duke Energy considered renewable technologies such as Onshore and Offshore Wind, Fixed and Single Axis Tracking (SAT) Solar PV, Landfill Gas, and Wood Bubbling Fluidized Bed (BFB). Duke also considered a variety of storage options such as Pumped Storage Hydro (PSH), Lithium-Ion (Li-Ion) Batteries, Flow Batteries, and Advanced Compressed Air Energy Storage (CAES) in the screening analysis. Lastly, a hybrid of the above technologies was considered: SAT Solar PV with Li-Ion Storage.

For the 2020 IRP screening analysis the Company screened technology types within their own respective general categories of baseload, peaking/intermediate, renewable, and storage with the goal of screening to pass the best alternatives from each of these four categories to the integration process. As in past years the reason for the initial screening analysis is to determine the most viable and cost-effective resources for further evaluation on the DEC system. This initial screening evaluation is necessary to narrow down options to be further evaluated in the quantitative analysis process as discussed in Appendix A.

The results of these screening processes determine a smaller, more manageable subset of technologies for detailed analysis in the expansion planning model. Table 8-A details the technologies that were evaluated in the screening analysis phase of the IRP process. The technical and economic screening is discussed in detail in Appendix G.

TABLE 8-A

TECHNOLOGIES SELECTED FOR ECONOMIC SCREENING

DISPATCHABLE (WINTER RATINGS)			
BASELOAD	**PEAKING / INTERMEDIATE**	**STORAGE**	**RENEWABLE**
601 MW, 1x1x1 Advanced Combined Cycle (No Inlet Chiller and Fired)	18 MW, 2 x Reciprocating Engine Plant	10 MW / 10 MWh Lithium-ion Battery	75 MW Wood Bubbling Fluidized Bed (BFB, biomass)
1,224 MW, 2x2x1 Advanced Combined Cycle (No Inlet Chiller and Fired)	15 MW Industrial Frame Combustion Turbine (CT)	10 MW / 20 MWh Lithium-ion Battery	5 MW Landfill Gas
782 MW Ultra-Supercritical Pulverized Coal with CCS	192 MW, 4 x LM6000 Combustion Turbines (CTs)	10 MW / 40 MWh Lithium-ion Battery	**NON-DISPATCHABLE (NAMEPLATE)**
557 MW, 2x1 IGCC with CCS	201 MW, 12 x Reciprocating Engine Plant	50 MW / 200 MWh Lithium-ion Battery	150 MW Onshore Wind
720 MW, 12 Small Modular Reactor Nuclear Units (NuScale)	752 MW, 2 x J-Class Combustion Turbines (CTs)	50 MW / 300 MWh Lithium-ion Battery	600 MW Offshore Wind
2,234 MW, 2 Nuclear Units (AP1000)	913 MW, 4 x 7FA.05 Combustion Turbines (CTs)	20 MW / 160 MWh Redox Flow Battery	75 MW Fixed-Tilt (FT) Solar PV
9 MW Combined Heat & Power (Reciprocating Engine)		250 MW / 4,000 MWh Advanced Compressed Air Energy Storage	75 MW Single Axis Tracking (SAT) Solar PV
21 MW – Combined Heat & Power (Combustion Turbine)		1,400 MW Pumped Storage Hydro (PSH)	75 MW SAT Solar PV plus 20 MW / 80 MWh Lithium-ion Battery

9 RESOURCE ADEQUACY

Resource adequacy means having sufficient resources available to reliably serve electric demand especially during extreme conditions.[1] Adequate reserve capacity must be available to account for unplanned outages of generating equipment, economic load forecast uncertainty and higher than projected demand due to weather extremes. The Company utilizes a reserve margin target in its IRP process to ensure resource adequacy. Reserve margin is defined as total resources[2] minus peak demand, divided by peak demand. The reserve margin target is established based on probabilistic reliability assessments.

2020 RESOURCE ADEQUACY STUDY

DEC and DEP retained Astrapé Consulting to conduct new resource adequacy studies to support the Companies' 2020 IRPs.[3] The Companies utilized a stakeholder engagement process which included participation from the NC Public Staff, SC Office of Regulatory Staff and the NC Attorney General's Office. The Companies hosted an in-person meeting on February 21, 2020 to provide an overview of the study methodology and model, and to review input data. The Companies worked with stakeholders to define Base Case assumptions and develop a list of planned sensitivities. The

[1]NERC RAPA Definition of "Adequacy" - The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components.
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf, at 9.
[2] Total resources reflect contribution to peak values for intermittent resources such as solar and energy limited resources such as batteries.
[3] Astrapé Consulting is an energy consulting firm with expertise in resource adequacy and integrated resource planning. Astrapé also conducted resource adequacy studies for DEC and DEP in 2012 and 2016.

Companies and Astrapé presented preliminary results to stakeholders on May 8, 2020 and presented recommended reserve margin targets on May 27, 2020.

Astrapé analyzed the optimal planning reserve margin based on (i) providing an acceptable level of physical reliability and (ii) analyzing economic costs to customers at various reserve levels. The most common physical reliability metric used in the industry is to target a reserve margin that satisfies the one day in 10 years Loss of Load Expectation (0.1 LOLE) standard.[4] This standard is interpreted as one firm load shed event every 10 years due to a shortage of generating capacity. The Company and Astrapé believe that physical reliability metrics should be used for determining the planning reserve margin since customers expect a reliable power supply during extreme hot summer conditions and extreme cold winter weather conditions.

Customer costs provide additional information in resource adequacy studies. 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 probability of reliability events increases along with an increase in the cost of energy. Thus, there is an economic optimum point where the total system costs (total energy costs plus the cost of unserved energy plus the capacity cost of incremental reserves) are minimized.

All inputs were updated in the new study. Current solar projections increased compared to the 2016 study which shifted more LOLE from summer to winter. As in the 2016 study, winter load volatility remains a significant driver of the reserve margin requirement. In response to stakeholder feedback, the 4-year ahead economic load forecast error (LFE) was diminished by providing a higher probability weighting on over-forecasting scenarios relative to under-forecasting scenarios. As discussed more fully below, this assumption essentially removed any economic load forecast uncertainty from the modeling and put downward pressure on the reserve margin target. Please reference the 2020 Resource Adequacy Study report included as Attachment III for further details regarding inputs and assumptions. Results of the study are presented below.

[4] https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf; Reference Table 14 in Appendix A, at A-1. PJM, MISO, NYISO, ISO-NE, Quebec, IESO, FRCC, APS, and NV Energy all use the 1 day in 10-year LOLE standard. As of this report, it is Astrapé's understanding that Southern Company has shifted to the greater of the economic reserve margin or the 0.1 LOLE standard.

ISLAND CASE

Astrapé ran an Island Case to determine the level of reserves that would be needed assuming no market assistance is available from neighbor utilities. Results showed that the Company would need to carry a 22.5% reserve margin in the Island Case to satisfy a 0.1 LOLE without neighbor assistance.

BASE CASE

Base Case results reflect the reliability benefits of the interconnected system including the diversity in load and generator outages across the region. Base case results for DEC showed that a 16.0% reserve margin is needed to maintain a 0.1 LOLE. Comparing Base Case results (16.0% reserve margin) to the Island Case (22.5% reserve margin) highlights the significant benefit of being interconnected to neighboring electric systems in the southeast. However, as discussed in more detail in the study report, there are limits and risks associated with too much dependence on neighboring systems during peak demand periods. Careful consideration of the appropriate reliance on neighboring systems is a key consideration in the determination of an appropriate planning reserve margin.

From an economic perspective, Astrapé analyzed total system costs across a range of reserve margins which resulted in a weighted average economic risk neutral reserve margin of 15.0%. The risk neutral level of reserves represents the weighted average results of all iterations at each reserve margin level. However, there are high risk scenarios within the risk neutral result that could cause customer rates to be volatile from year to year. This volatility can be diminished by carrying a higher level of reserves. The study showed that the 90th percentile cost curve resulted in a reserve margin of 16.75%. Please reference the economic reliability results presented in the Executive Summary of the study report for further details regarding the potential capital costs and energy savings at different reserve margin levels.

Base Case results for DEP showed that a 19.25% reserve margin is needed to meet a 0.1 LOLE. The higher physical reserve margin for DEP compared to DEC is driven primarily by greater winter load volatility, and to a lesser extent less import capability. The weighted average risk neutral economic results for DEP yielded a reserve margin of 10.25%[5] and the 90th percentile cost curve resulted in a reserve margin of 17.5%.

[5] Given the significant level of solar on the DEP system, summer reserve margins are approximately 12% greater than winter reserve margins. Thus, the risk neutral reserve margin of 10.25% for DEP is significantly lower than the 19.25%

COMBINED CASE RESULTS

Astrapé also simulated a Combined Case to approximate the reliability benefits of operating the DEC and DEP generation systems as a single balancing authority. This scenario allowed preferential reliability support between DEC and DEP to share capacity, operating reserves and demand response capability. The Combined Case results showed that a 16.75% reserve margin is needed to meet the 0.1 LOLE. The weighted average risk neutral economic results for the Combined Case yielded a reserve margin of 17.0% and the 90th percentile confidence level scenario resulted in a reserve margin of 17.75%.

SENSITIVITIES

A range of sensitivities was simulated in the study to understand which assumptions and inputs impact study results and to address questions and requests from stakeholders. Sensitivities included both physical and economic drivers of reserve margin. Please reference the study report for a detailed explanation of each sensitivity and the reliability and economic results.

TARGET RESERVE MARGIN

Based on the physical and economic reliability results of the Island Case, Base Case, Combined Case, and all sensitivities for both DEC and DEP, Astrapé recommends that DEC and DEP continue to maintain a minimum 17% reserve margin for IRP planning purposes. The Company supports this recommendation and further notes that the results of the Combined Case physical LOLE reserve margin (16.75%), weighted average risk neutral economic reserve margin (17.0%) and 90th percentile economic reserve margin (17.75%) converge on a reserve margin of approximately 17.0%.[6]

As discussed more fully below, the sensitivity results that remove all economic load forecast uncertainty actually increase the reserve margin required to meet 0.1 LOLE. Thus, Astrapé and the Company

reserve margin required to meet 0.1 LOLE since there is little economic benefit of additional reserves in the summer and the majority of the savings seen in adding additional capacity is only being realized in the winter.

[6] In 2019, DEC and DEP entered into an as-available capacity sales agreement which allows the companies to sell excess capacity to the sister utility. This agreement allows the Companies to take advantage of excess capacity available from the sister utility and thus provides some of the enhanced reliability benefits assumed in the Combined Case.

recommend that this minimum target be used in the short- and long-term planning process. A 17% reserve margin provides adequate reliability to customers but also provides rate stabilization by removing the volatility seen in the coldest years, and thus strikes a reasonable balance between reliability and cost. Similar to the 2016 resource adequacy study, Astrapé also recommends maintaining a minimum 15% reserve margin across the summer. Given the resource portfolio in the Base Case, the 15% summer reserve margin will always be met if a 17% winter target is met.

SUPPLEMENTAL INFORMATION

SHORT-TERM VERSUS LONG-TERM RESOURCE PLANNING

The NCUC notes on page 12 of its 2019 IRP order:

> The Commission notes with interest that the Companies appear to acknowledge that it is possible that short-term reserve capacity could fall below the long-term target of 17% without posing a significantly increased risk of resource inadequacy.

This statement is in reference to Duke's response to an NCUC question regarding prior reserve margin targets. Duke stated in its response:[7]

> DEP determined that an 11% capacity margin (12.4% reserve margin) may be acceptable in the near term when there is greater certainty in forecasts; however, a 12%-13% capacity margin (13.6%-14.9% reserve margin) is appropriate in the longer term to compensate for possible load forecasting uncertainty, uncertainty in DSM/EE forecasts, or delays in bringing new capacity additions online.

Astrapé included economic load forecast error in the study to capture the uncertainty in Duke's 4-year ahead load forecast. Four years is the approximate amount of time it takes to permit and construct a new resource. In the 2016 study, the LFE was fit to a normal distribution reflecting equal probably of over-forecasting or under-forecasting load, which resulted in an increase in reserve margin of approximately 1.0-1.5% to account for forecast uncertainty. However, based on stakeholder feedback,

[7] Duke's Responses, Docket No. E-100, Sub 157, at p.19.

the 4-year ahead economic LFE in the 2020 study was diminished by using an asymmetric distribution with higher probability weightings on over-forecasting scenarios relative to under-forecasting scenarios. The Company and Astrapé accepted this modeling change in the study; however, it is noted that tailwinds of economic growth such as the adoption rate of electric vehicles and the rate of electrification of end-uses may result in additional load growth uncertainty not captured in the study.

Since there is greater certainty in load in the near term versus longer term, it was anticipated that removal of the LFE uncertainty may support a lower reserve margin in the near term. Interestingly, however, Astrapé ran a sensitivity that removed the LFE uncertainty and results showed a slightly higher reserve margin was required (0.25%) compared to the Base Case. Astrapé ran a second sensitivity that removed the asymmetric Base Case distribution and replaced it with the originally proposed normal distribution. The minimum reserve margin for 0.1 LOLE increased by 1.0% in the Base Case to 17.0%. Since removing the LFE actually increases the reserve margin required to meet the 0.1 LOLE standard (since over-forecasting load is more heavily weighted than under-forecasting load), Astrapé and the Company believe that a 17% minimum reserve margin is appropriate to use for each year of the planning period.

The NCUC also states on page 11 of its 2019 IRP order:

> In terms of risk or volatility, the Commission does not view the differences in Total System Costs are enough to warrant a "hard and fast" minimum reserve margin for planning. This is not to say that the minimum reserve margins supported by the 2016 Astrapé Study are not valid for planning. Rather, the Commission's guidance is that the Companies should not be constrained in their planning to produce resource plans that meet the indicated minimum target reserve margin in each and every one of the plan years.

While the Company supports the general application of a 17% reserve margin target for each year of the planning period, per the NCUC's guidance, the Company will not employ this target as a "hard and fast" constraint in every plan year. Rather, the Company will consider letting reserves decline below 17% in certain circumstances as long as the risk of a loss of load event is not unreasonably compromised. As an example, in the 2020 DEP IRP, reserves were allowed to drop below 17% in 2024 (16.8%) and 2025 (16.6%). At this time, DEP does not plan to make short-term market purchases to satisfy a 17% minimum target; however, DEP will continue to monitor changes in the load forecast and the resource mix and will adjust accordingly.

APPROPRIATENESS OF USING THE 0.1 LOLE STANDARD

Customers expect a high level of power reliability, especially during periods of extreme hot or cold weather events. While some power outages may be beyond the Company's control, such as events caused by hurricanes or other natural disasters, customers and regulators expect power to be available during extreme hot and cold periods to power their homes and businesses.[8] As previously noted, the 0.1 standard is widely used across the electric industry and the Company continues to apply the 0.1 LOLE target to determine the level of reserves needed to provide adequate generation reliability. Although this target does not eliminate reliability risk, the Company believes it does provide the level of reliability that customers expect without being overly excessive. The NCUC noted in its 2019 IRP order:[9]

> At this point the Commission is disinclined to direct that in their 2020 IRPs DEC and DEP use some alternative measure of resource inadequacy other than the LOLE .1 standard.

As further support for use of the 0.1 LOLE standard, the Company presents Table 9-A below which shows actual operating reserves during extreme winter weather events for the period 2014-2019. The table shows a total of 13 occurrences when operating reserves declined below 10%, with four occurrences below 5% and three occurrences below 2%. The lowest operating reserve of 0.2% occurred on January 7, 2014. The table also shows the planning reserve margin as projected in the prior year's IRP. For example, on January 7, 2014, actual operating reserves dropped to 0.2% even though the Company's 2013 IRP projected a planning reserve margin of 24.8% based on normal weather for the winter of 2013/2014. The 24.8% projected reserve margin was approximately 8% above the Company's minimum planning target of 17%. It is almost certain DEC would have shed firm load in 2014 had the reserve margin going into the winter been 17%. For the 13 occurrences with operating reserves below 10%, planning reserves ranged from approximately 21% to 28%. Yet, without non-firm market assistance the Company would have shed firm load. This information is also

[8] Section (b)(4)(iv) of NCUC Rule R8-61 (Certificate of Public Convenience and Necessity for Construction of Electric Generation Facilities) requires the utility to provide "… a verified statement as to whether the facility will be capable of operating during the lowest temperature that has been recorded in the area using information from the National Weather Service Automated Surface Observing System (ASOS) First Order Station in Asheville, Charlotte, Greensboro, Hatteras, Raleigh or Wilmington, depending upon the station that is located closest to where the plant will be located."

[9] NCUC Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans, April 6, 2020, at 10.

shown graphically in Figure 9-A below. History has shown that adherence to the 0.1 LOLE standard has provided customers with adequate reliability without carrying an excessive level of planning reserves.

The 0.1 LOLE target is widely used in the industry for resource adequacy planning. The Combined Case economic reserve margin study results presented earlier give similar results to the 0.1 LOLE target of a 17% reserve margin. Further, actual operating reserves history has shown that planning to the 0.1 LOLE standard has provided adequate reliability without having excessive actual reserves at the time of winter peak demands. The Company and Astrapé continue to support use of the 0.1 LOLE for resource adequacy planning.

TABLE 9-A

DEC ACTUAL HISTORIC OPERATING RESERVES[10]

RANK (LOWEST TO HIGHEST OPERATING RESERVES)	DATE	PEAK DEMAND (MW)	OPERATING RESERVES* (%)	IRP RESERVE MARGIN** (%)
1	1/7/2014	18,626	0.2	24.8
2	2/20/2015	18,589	1.2	27.6
3	1/8/2015	17,974	1.9	27.6
4	1/30/2014	19,151	2.4	24.8
5	01/02/18	20,890	5.3	21.2
6	01/25/19	16,906	5.9	24.1
7	03/06/19	17,124	6.6	24.1
8	1/24/2014	18,550	7.0	24.8
9	01/31/19	18,875	7.2	24.1
10	2/19/2015	17,427	7.6	27.6
11	01/05/18	21,620	8.0	21.2
12	12/06/18	17,742	9.3	21.2
13	01/11/19	17,705	9.5	24.1

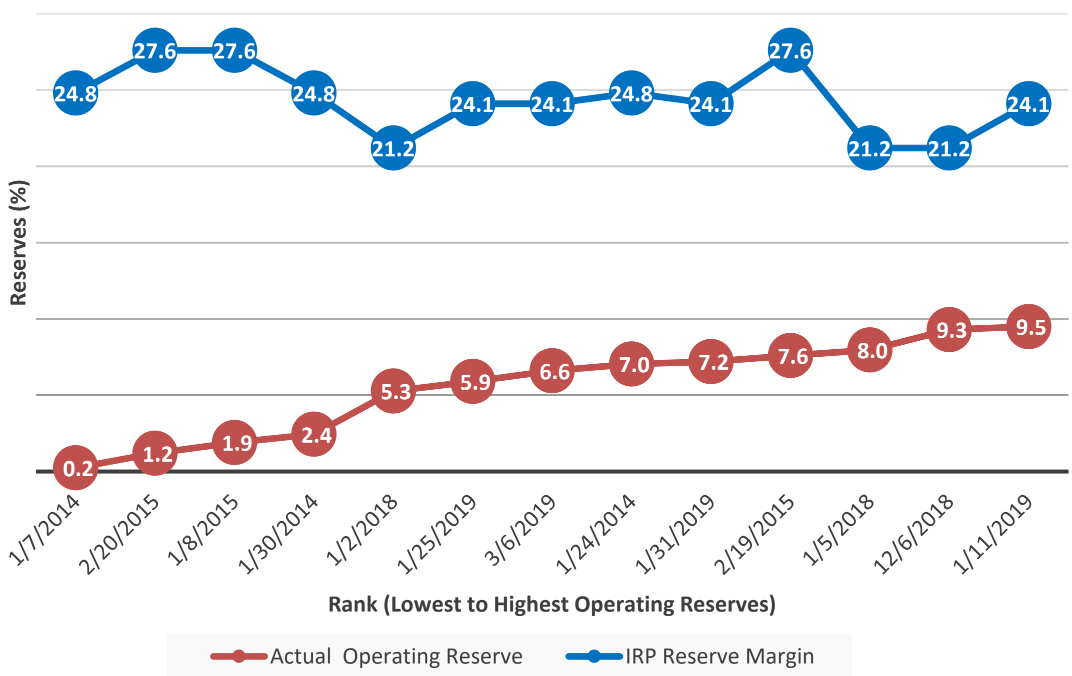
*Operating Reserves represent an estimate based on the last snapshot of projected reserves at the peak for each respective day and include the effects of DR programs that were activated at the time of the peak.

**IRP Reserve Margin reflects the projected reserve margin based on normal weather peak from the previous year's IRP.

[10] The operating reserves shown do not reflect non-firm energy purchases during the hour of the peak system demand in order to ensure a fair comparison with planning reserve margins which also do not include such non-firm purchases that may or may not be available during peak demand hours. The operating reserves data is based on Public Staff data request responses in past IRP dockets.

FIGURE 9-A

DEC ACTUAL HISTORIC OPERATING RESERVES



REGIONAL MODELING

It is important to note that Base Case results reflect the regional benefits of relying on non-firm market capacity resulting from the weather diversity and generator outage diversity across the interconnected system. However, there is risk in over reliance on non-firm market capacity. The Base Case reflects a 6.5% decrease in reserve margin compared to the Island Case (from 22.5% to 16.0%). Thus, approximately 29% (6.5/22.5 = 29%) of the Company's reserve margin requirement is being satisfied by relying on the non-firm capacity market. Astrapé and Duke believe that this market reliance is moderate to aggressive, especially when compared to surrounding entities such as PJM Interconnection L.L.C. (PJM) and the Midcontinent Independent System Operator (MISO). For example, PJM limits market assistance to 3,500 MW which represents approximately 2.3% of its reserve margin, compared to 6.5% assumed for DEC.[11] Similarly, MISO limits market assistance to 2,331 MW which represents approximately 1.8% of its reserve margin.[12]

As noted in the Executive Summary of the study report, the general trend across the country is a shift away from coal generation with greater reliance on renewable energy resources. As an example, the Dominion Energy (Virginia Electric and Power Company) 2020 IRP shows substantial additions of solar, wind and battery storage to comply with the recent passage of the Virginia Clean Economy Act (VCEA). The excerpt below is from page 6 of the 2020 Dominion IRP:[13]

> In the long term, based on current technology, other challenges will arise from the significant development of intermittent solar resources in all Alternative Plans. For example, based on the nature of solar resources, the Company will have excess capacity in the summer, but not enough capacity in the winter. Based on current technology, the Company would need to meet this winter deficit by either building additional energy storage resources or by buying capacity from the market. In addition, the Company would likely need to import a significant amount of energy during the winter, but would need to export or store significant amounts of energy during the spring and fall.

Dominion notes its anticipated "need to import a significant amount of energy during the winter" which means Dominion's greater reliance on PJM and other neighbors in the future. Additionally, PJM now considers the DOM Zone to be a winter peaking zone where winter peaks are projected to exceed summer peaks for the forecast period.[14] The Company also notes California's recent experience with rolling blackouts under extreme weather conditions, as the state continues its shift away from fossil-fuel resources with greater reliance on intermittent renewable resources, storage and imported power.[15]

Duke and Astrapé believe the recommended 17% reserve margin is adequate for near term

[11] https://www.pjm.com/-/media/committees-groups/subcommittees/raas/20191008/20191008-pjm-reserve-requirement-study-draft-2019.ashx - at 1.

[12] https://www.misoenergy.org/api/documents/getbymediaid/80578 - at 24. (copy and paste link in browser)

[13] Dominion Energy (Virginia Electric and Power Company) filed its 2020 IRP as the Astrapé study was underway. Dominion's 2020 IRP can be found at https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/2020-va-integrated-resource-plan.pdf?la=en&rev=fca793dd8eae4ebea4ee42f5642c9509.

[14] Dominion Energy 2020 IRP, at 40.

[15] https://www.greentechmedia.com/articles/read/how-californias-shift-from-natural-gas-to-solar-is-playing-a-role-in-rolling-blackouts.

Corrected 11.06.2020

planning and appropriately captures the diversity in load and unit outage events with PJM and other neighbors. The Company used the 17% reserve margin target for the entire 15-year planning period in the IRP. However, changes in resource portfolios of neighboring utilities, as well as the experience in other states to meet extreme weather peak demands with high renewables portfolios, make reliability planning more challenging and place less confidence in future market assistance. For example, today neighboring systems with load diversity may be willing to turn fossil units on early or leave them running longer to assist an adjoining utility during a peak demand period. In the future, with the potential for battery storage to replace a portion of retiring fossil generation, neighboring systems may be reluctant to sell stored energy if they believe that limited stored energy may be required for their native load. Thus, future resource adequacy studies may show less regional benefit of the interconnected system, resulting in the need to carry greater reserves in the longer term. Duke will continue to monitor changes that may impact resource adequacy.

ADEQUACY OF PROJECTED RESERVES

The IRP provides general guidance in the type and timing of resource additions. Projected reserve margins will often be somewhat higher than the minimum target in years immediately following new generation additions since capacity is generally added in large blocks to take advantage of economies of scale. Large resource additions are deemed economic only if they have a lower Present Value Revenue Requirement (PVRR) over the life of the asset as compared to smaller resources that better fit the short-term reserve margin need.

DEC's resource plan reflects winter reserve margins ranging from approximately 17.1% to 25.3%. Reserves projected in DEC's IRP meet the minimum planning reserve margin target and thus satisfy the 0.1 LOLE criterion. Projected reserve margins exceed the minimum 17% winter target by 3% or more in 2021, 2022, 2023 and 2025, primarily as a result of a reduction in the load forecast. The Lincoln CT addition and full deployment of IVVC also contribute to the higher reserves in 2025.

10 NUCLEAR AND SUBSEQUENT LICENSE RENEWAL (SLR)

NUCLEAR ASSUMPTIONS IN THE 2020 IRP

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

SUBSEQUENT LICENSE RENEWAL (SLR) FOR NUCLEAR POWER PLANTS

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

License Renewal is governed by Title 10 of the Code of Federal Regulations (10 CFR) Part 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants.* The NRC has approved applications to extend licenses to up to 60 years for 94 nuclear units across the country.

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

NextEra submitted the industry's first SLR application to the NRC on January 31, 2018 for its Turkey Point station, which became the first nuclear units to receive a second renewed license in December 2019. The NRC review was completed in approximately 18 months from the completion of the sufficiency review.

On July 10, 2018, Exelon Corporation submitted an SLR application for its Peach Bottom plant. The Peach Bottom second renewed license was issued in March 2020, also in approximately 18 months from the completion of the sufficiency review.

Dominion Energy submitted an SLR application for its Surry station on October 15, 2018 and is currently in the final stages of the process of receiving its second renewed license. Dominion Energy plans to submit an SLR application for its North Anna plants in 2020.

Based on the technologically safe and reliable operation of the Duke Energy nuclear fleet, the economic benefits of continued operation of the current nuclear fleet and the environmental role played by the nuclear fleet to continue to reduce carbon emissions, Duke Energy announced in September 2019 its intent to pursue SLR for all eleven nuclear units in the operating fleet. The Oconee SLR application will be submitted first, in 2021. An SLR application takes approximately three years to prepare and approximately two years to be reviewed and approved.

11 COAL RETIREMENT ANALYSIS

For more than 60 years, coal assets in the DEC fleet have provided reliable capacity and energy to DEC's customers. These assets continue to provide year-round energy that is especially critical during winter and summer peaks. However, as the industry landscape changes and market forces drive down costs of other resources, it is important to continue to evaluate the economic benefit the coal fleet provides to customers.

In order to assess the on-going value of these assets, DEC conducted a detailed coal plant retirement analysis to determine the most economic retirement dates for each of the Company's coal assets. This analysis identified the retirement dates used in the Base Cases developed with and without Carbon Policy for each of DEC's coal plants. In addition to the economic retirement analysis, the Company also determined the earliest practicable retirement dates for each coal asset. The "earliest practicable" retirement date portfolio is discussed in Appendix A.

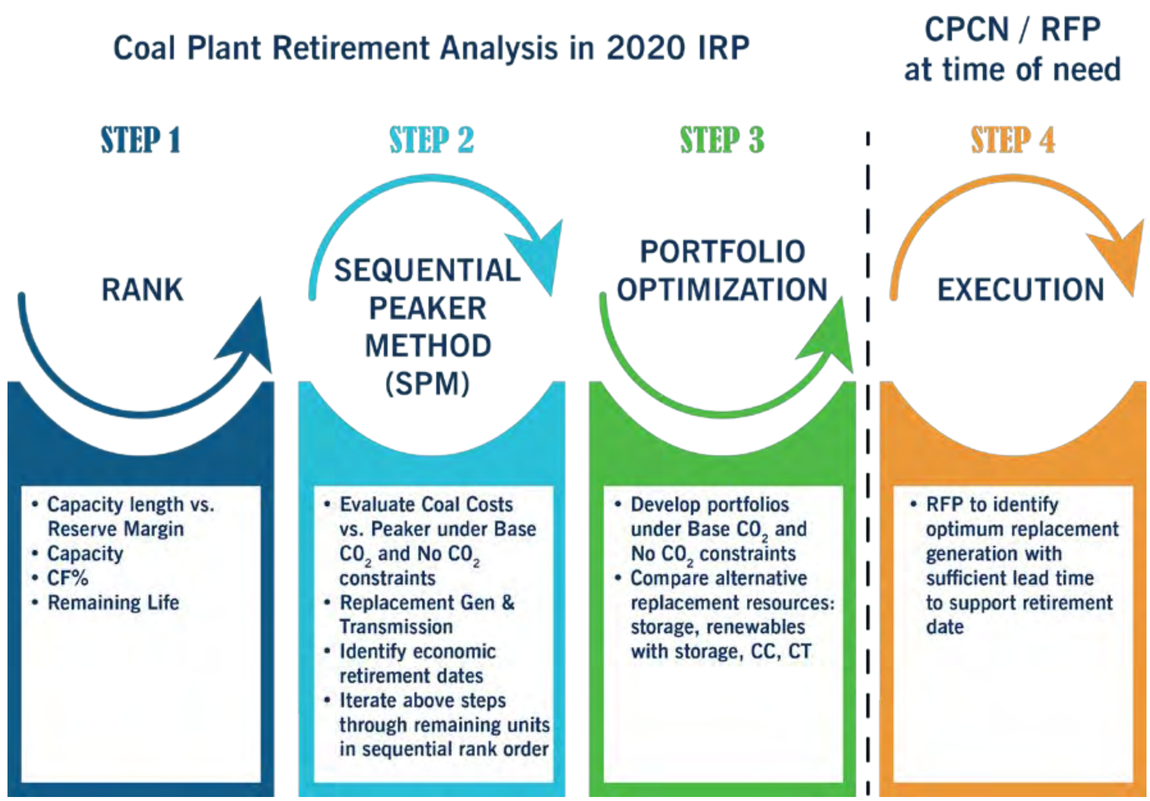
The retirement dates discussed in this chapter do not represent commitments to retire. The IRP is a planning document, but the execution of the plan can vary for multiple reasons including changes to the load forecast, market conditions, and generator performance just to name a few. Similar to new undesignated resources identified in this document that do not have an approval to build or a commitment to build, the coal retirement dates presented herein only represent the current economic retitement dates and are not a commitment to retire.

FOUR-STEP PROCESS

The economic retirement dates, along with the optimum replacement generation, of the coal plants were determined through the process depicted in the diagram below.

FIGURE 11-A

PROCESS FOR DETERMINING ECONOMIC RETIREMENT DATES AND REPLACEMENT GENERATION OF COAL PLANTS



The first three steps of the process include both identifying the most economic date and the most economic replacement resources for the retiring coal plants. These steps are included in the 2020 IRP and are detailed in the discussion below. Steps 2 & 3 were evaluated under Base Cases with and without Carbon Policy.

The fourth step in the process, or the execution step, occurs outside of the IRP when the retirement date for the plant is finalized and replacement resource needs are determined. Importantly, the Company includes assumptions for future costs and the commercial availability of replacement resources in the first 3 steps of the retirement analysis, as well as throughout the entirety of the IRP. Only at the time of execution, when the Company issues an RFP for replacement resources, will the *actual* costs, availability, and need for those resources be known.

STEP 1: RANKING PLANTS FOR RETIREMENT ANALYSIS

Due to the retirement of one asset impacting the operation and value of other assets on the system, it was important to identify the order in which to conduct the retirement analysis. Additionally, the Joint Dispatch Agreement (JDA) between DEC and DEP allows for non-firm energy purchases and sales between the two utilities. Because of this interaction, the ranking of assets for retirement was evaluated across the utilities, and both DEC and DEP assets are presented below.

To rank the assets for retirement, the Company first ran preliminary capacity expansion plan and production cost models to determine the capacity factors (CF%) for each facility using the 2019 IRP coal plant retirement dates as a starting point for the analysis. This exercise was necessary for estimating future capital and fixed operating and maintenance (FOM) costs at the sites, including incremental coal ash management costs, as well as, for identifying the capacity length versus reserve margin to determine if replacement generation was needed when the individual plants were retired.

The results of Step 1 are shown in Table 11-A below:

TABLE 11-A

RANKING OF COAL PLANTS FOR RETIREMENT ANALYSIS

COAL FACILITY	CAPACITY (MW WINTER)	CF% RANGE THROUGH 2035	YEARS IN SERVICE (AS OF 1/2020)	RANK
Allen 1 – 3	604	3% – 11%	60 – 62	1
Allen 4&5	526	2% - 9%	58 – 59	2
Cliffside 5	546	2% - 23%	47	3
Mayo	746	1% - 12%	36	4
Roxboro 1&2	1,053	5% - 34%	51 – 53	5
Roxboro 3&4	1,409	1% - 32%	39 – 46	6
Marshall 1-4	2,078	1% - 49%	49 – 54	7
Belews Creek 1&2	2,220	16% - 57%	44 – 45	8

Because the cost of replacement generation for coal plants is a critical factor when determining the value of retirement, the Company considered the capacity of the plant to be one of the most important factors for determining the order in which to conduct the retirement analysis. For instance, while Cliffside 5 has a higher capacity factor than Mayo, which would indicate Cliffside 5 has higher production cost value, the lower capacity of Cliffside 5 requires less replacement generation at the time of retirement. For this reason, Cliffside 5 was ranked above Mayo in the order for conducting the retirement analysis. Cliffside 6 was not evaluated in the ranking step as its ability to burn 100% natural gas provides flexibility that is valuable across the range of portfolios evaluated in this IRP.

STEP 2: SEQUENTIAL PEAKER METHOD (SPM)

Once the order to conduct the retirement analysis was determined, the next step was to determine the most economic date for each coal plant. As discussed above, as coal plants are retired, the value of the remaining coal plants in the fleet changes. For this reason, the Company evaluated the economic value of each plant in a sequential manner. Additionally, for determining the optimum retirement date, the Company used a Net Cost of New Entry (Net CONE) methodology when evaluating each plant. The Net CONE method is similar to the Peaker Method used in calculating avoided costs as it considers both the capital and fixed costs of a generic peaker, as well as, the net production cost value of the peaker versus the asset the peaker is replacing. Importantly, this step is used solely to determine the optimal date for retirement. In Step 3, or the Portfolio Optimization step, the optimum replacement generation is determined, considering alternative technology options such as solar, wind, battery storage, solar + storage, and natural gas generation to determine the lowest total cost resource mix to support the aggregate defined economic retirement dates.

In addition to accelerating the cost of the replacement peaker and the impacts to the system variable production costs, the second step also considered the on-going capital and fixed operating costs avoided by accelerating the retirement date of the coal plant. For example, the avoided costs included any incremental coal ash management costs, including estimates for new landfill cells that would have been required to store incremental coal ash generated through continued operation of these plants.

Finally, the Sequential Peaker Method included the cost to accelerate transmission upgrades associated with the retirement of some of the coal plants. In several instances, the retiring coal plant or units provided support to the transmission system, and in those cases, the Company included the cost of Static Var Compensators (SVCs) and/or line upgrades to address the loss of generation on the system.

The figure below presents a high-level view of how the SPM analysis was conducted, and the results of the analysis are presented in Table 11-B. While not shown in the graphic below, Allen Units 1-5 were evaluated in an initial step once it was determined replacement generation would not be needed since there was sufficient capacity above reserve margin requirements prior to 2025. For all other units, the Company assumed replacement generation or the necessary transmission upgrades needed to retire the facilities would not be available until 2025, and therefore the earliest date any plant after Allen Units 1-5 could be retired was considered to be 2025.

FIGURE 11-B

SEQUENTIAL PEAKER METHOD PROCESS FOR DETERMING ECONOMIC RETIREMENT DATES OF COAL PLANTS

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The table below shows the economic retirement dates for each coal plant as determined via the Sequential Peaker Method.

TABLE 11-B
ECONOMIC RETIREMENT DATES OF COAL PLANTS FROM SPM

COAL PLANT	BASE CASE W/ CO_2 POLICY MOST ECONOMIC RETIREMENT YEAR (JAN 1)[1]
Allen 2 – 4	2022
Allen 1 & 5	2024
Cliffside 5	2026
Roxboro 3 & 4	2028
Roxboro 1 & 2	2029
Mayo 1	2029
Marshall 1 – 4	2035
Belews Creek 1	2039
Belews Creek 2	2039
Cliffside 6	2049

As demonstrated through the SPM step, Allen unit retirements in 2022 (YE 2021) and 2024 (YE 2023) and the associated new South Point switchyard, which is necessary to allow for the retirement of all five Allen units, will bring economic value to customers and further the clean energy goals held by the Company and stakeholders. As with all unit retirement dates in the IRP, this is not a commitment

[1] There was no appreciable difference between the economic retirement dates in the Base Case with Carbon policy and Base Case without Carbon policy.

to retire the Allen units on this timeline but rather contains the Company's most recent estimate of retirement economics at the time of this filing. Official retirement will require final management approval with final retirement dates contingent upon the finalization of the supporting switchyard project and other operational considerations.

With the potential retirement of Allen Steam Station on the horizon, it is noteworthy that the facility has provided reliable energy to the Carolinas for over 60 years.

STEP 3: PORTFOLIO OPTIMIZATION

After the most economic retirement dates were determined, the Company relied on expansion plan and system production cost modeling to develop two optimized portfolios with the assumption that coal units were retired on the dates determined in Step 2. These optimized portfolios represent the Base Plan with Carbon Policy and Base Plan without Carbon Policy discussed in greater detail in Chapter 12 and Appendix A, and replacement generation includes a mix of solar, solar plus storage, standalone storage, wind, EE/DSM, and natural gas generation.

The development of these optimized portfolios was based on the best available projections of fuel, technology, carbon, and other costs known at the time the inputs to the IRP were developed. As the economics of continued coal operations change relative to the costs of replacement resource alternatives, future IRPs will reflect such changes. However, it is only when units are ultimately planned for retirement in the future, with specific replacement resources identified at specific locations, that the actual costs for replacement resources can be known. Importantly, with the exception of the Allen units, all further coal unit retirements will require replacement resources to be in service prior to the physical retirement of the coal facility in order to maintain system reliability. It is at that time that the actual costs of replacement resources from Step 4, or the Execution step, will be determined as part of a future CPCN and associated RFP process.

As previously noted, in addition to the most economic retirement dates for the coal plants, the Company also developed the earliest practicable retirement dates for each plant. The earliest practicable dates were determined without considerations of least cost planning, and they represent the earliest date plants could be retired when considering transmission, fuel, replacement generation, and other logistical requirements. The methodology and results of the earliest practicable retirement date analysis is presented in Appendix A.

12 EVALUATION AND DEVELOPMENT OF THE RESOURCE PLAN

As described in Chapter 9, DEC continues to plan to winter planning reserve margin criteria in the IRP process. To meet the future needs of DEC's customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, DEC develops a load forecast of cumulative energy sales and hourly peak demand. To determine total resources needed, the Company considers the peak demand load obligation plus a 17% minimum planning winter reserve margin. The projected capability of existing resources, including generating units, EE and DSM, renewable resources and purchased power contracts is measured against the total resource need. Any deficit in future years will be met by a mix of additional resources that reliably and cost-effectively meet the load obligation and planning reserve margin while complying with all environmental and regulatory requirements. A high-level representation of the IRP process is represented in Figure 12-A.

FIGURE 12-A
SIMPLIFIED IRP PROCESS

It should be noted that DEC considers the non-firm energy purchases and sales associated with the JDA with DEP in the development of its six portfolios, as discussed later in this chapter and in Appendix A.

THREE PILLARS OF THE IRP

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

FIGURE 12-B
THREE PILLARS OF THE IRP

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

- Environmental
- Financial (Affordability)
- Physical (Reliability)

The Environmental pillar of the IRP process takes into consideration various policies set by state and federal entities. Such entities include NCUC, PSCSC, FERC, NERC, SERC, NRC, and EPA, along with various other state and federal regulatory entities. Each of these entities develops policies that have a direct bearing on the inputs, analysis and results of the IRP process. While many regulatory and legislative policies impact the production of the IRP, the primary focus on both a state and national level is around environmental policies. Examples of such policies include NC HB 589, SC Act 236 and SC Act 62 programs that set targets for the addition of renewable resources. Environmental legislation at the state and federal level can impact the cost and operations of existing resources, as well as future assets. In addition, reliability and operational requirements imposed on the system influence the IRP process.

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

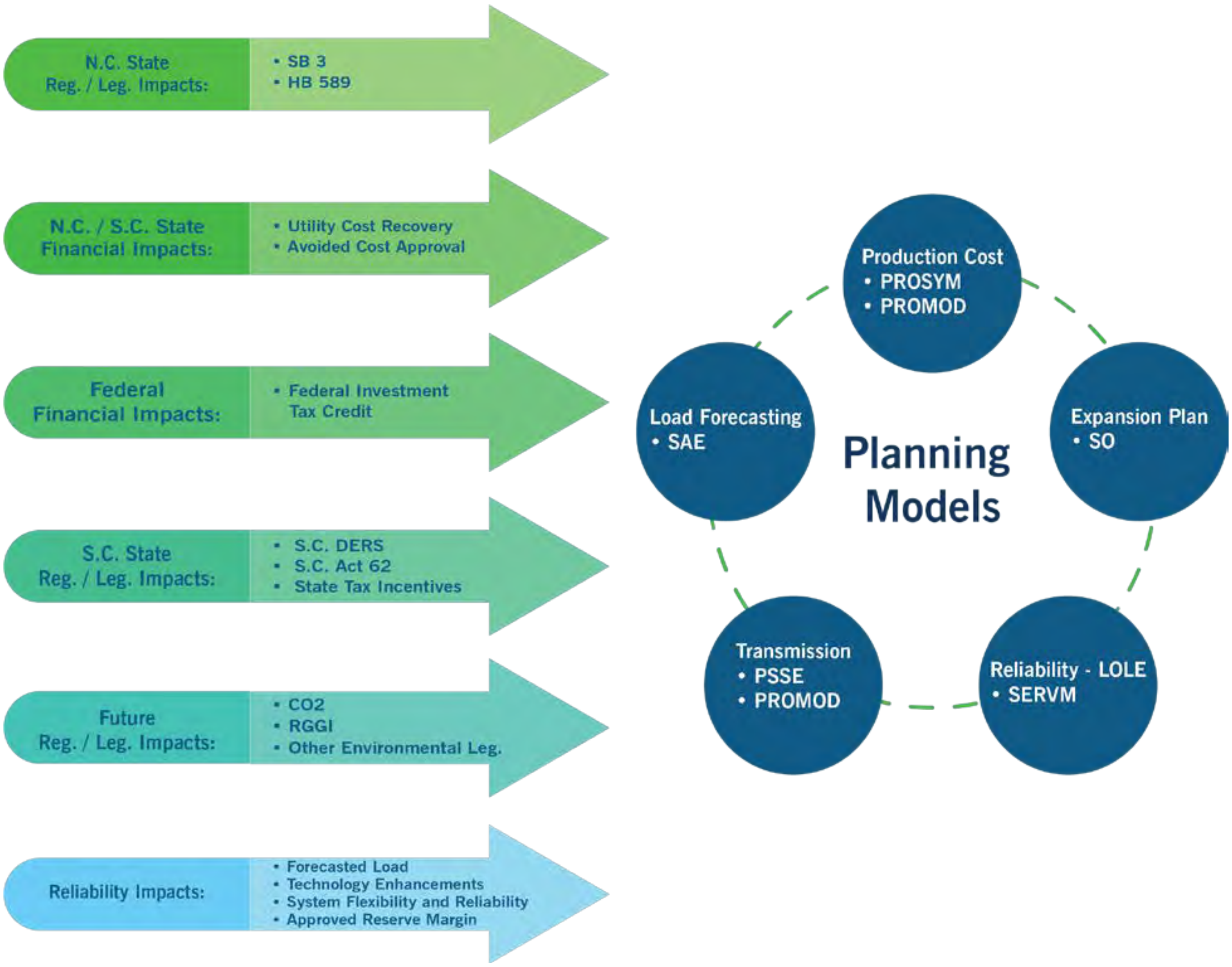
Finally, Physical Reliability is the third pillar of the IRP process. Reliability of the system is vitally important to meeting the needs of today's customers, as well as the future needs that come with substantial customer growth projected in the region. DEC's customers expect energy to be provided to them every hour of every day throughout the year without fail, today and into the future. To ensure the energy and capacity needs of the Company's customers are met, the Company continues to plan to a reasonable 17% reserve margin, which helps to ensure that the reliability of the system is maintained. A more detailed discussion of the reliability requirements of the DEC system is discussed in Chapter 9.

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

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

FIGURE 12-C

IMPACTS OF THREE PILLARS ON THE IRP MODELING PROCESS



IRP ANALYSIS PROCESS

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

DATA INPUTS

Refreshing input data is the initial step in the IRP development process. For the 2020 IRP, data inputs such as load forecast, EE and DSM projections, fuel prices, projected CO_2 prices, individual plant operating and cost information, and future resource information were updated with the most current data. These data inputs were developed and provided by Company subject matter experts and/or based upon vendor studies, where available. Furthermore, DEC and DEP continue to benefit from the combined experience of both utilities' subject matter experts utilizing best practices from each utility in the development of their respective IRP inputs. Where appropriate, common data inputs were utilized.

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

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

GENERATION ALTERNATIVE SCREENING

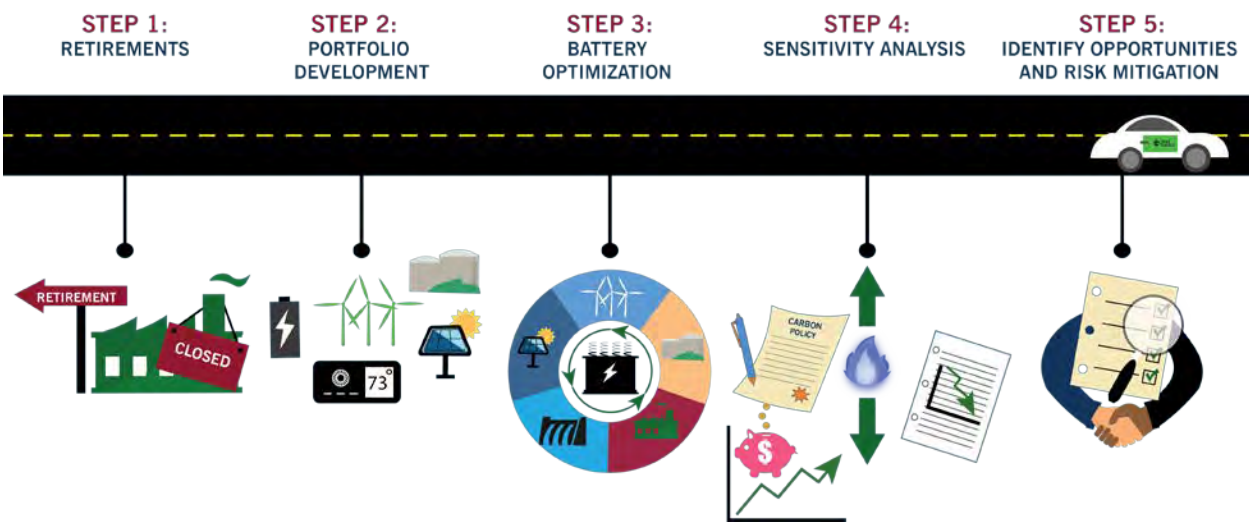
DEC reviews generation resource alternatives on a technical and economic basis. Resources must also be demonstrated to be commercially available for utility scale operations. The resources that are found to be both technically and economically viable are then passed to the detailed analysis process for further evaluation. The process of screening these resources is discussed in detail in Appendix G.

PORTFOLIO DEVELOPMENT AND SENSITIVITY ANALYSIS

The following figure provides an overview of the process for the portfolio development and detailed analysis phase of the IRP. The process is discussed in detail in Appendix A.

FIGURE 12-D

OVERVIEW OF PORTFOLIO DEVELOPMENT AND SENSITIVITY ANALYSIS PHASE



The Base Case Portfolio Development and Sensitivity Analysis phases rely upon the updated data inputs and results of the generation alternative screening process to derive resource portfolios or resource plans. The Base Case Portfolio Development and Sensitivity Analysis phases utilize an expansion planning model, System Optimizer (SO), to determine the best mix of capacity additions for the Company's short- and long-term resource needs with an objective of selecting a robust plan that meets reliability targets, minimizes the PVRR to customers and is environmentally sound by complying with or exceeding all State and Federal regulations.

Sensitivity analysis of input variables such as load forecast, fuel costs, renewable energy, EE, and resource capital costs are considered as part of the quantitative analysis within the resource planning process. Utilizing the results of these sensitivities, possible expansion plan options for the DEC system are developed. These expansion plans are reviewed to determine if any overarching trends are present across the plans, and based on this analysis, portfolios are developed to represent these trends. Finally, the portfolios are analyzed using a capital cost model and an hourly production cost model (PROSYM) under various fuel price and carbon scenarios to evaluate the robustness and economic value of each portfolio under varying input assumptions. After this comprehensive analysis is completed, the portfolios are examined considering the trade-offs between costs, carbon reductions, and dependency on technological and policy advancements.

In addition to evaluating these portfolios solely within the DEC system, the potential benefits of sharing capacity within DEC and DEP are examined in a common Joint Planning Case. A detailed discussion of these portfolios is provided in Appendix A.

SELECTED PORTFOLIOS

For the 2020 IRP, six portfolios were identified through the Base Case Portfolio Development and Sensitivity Analysis process that consider and attempt to address stakeholder interest in the transformation of the DEC generation fleet. As described below, the portfolios range from diverse intended outcomes ranging from least cost planning to high carbon reductions and resource restrictions. Additionally, some portfolios consider the increase in the amount and adoption rate of renewables, EE, and energy storage to achieve these outcomes.

PORTFOLIO A (BASE CASE WITHOUT CARBON POLICY)

This portfolio primarily selects new natural gas generation to meet load growth and replace retiring existing capacity. This case incorporates the most economic retirement dates for the coal units, as discussed in Chapter 11, which includes the retirement of 3,800 MW of coal capacity by the end of the IRP planning period. The base planning assumptions for expected renewable additions and interconnections, energy efficiency and demand response are also built into this plan, before a new resource is considered. Although no renewable resources were economically selected by the model, this case adds 2,700 MW of solar and solar plus storage throughout the IRP planning horizon. This plan also adds 150 MW of battery storage placeholders to the system in the early- to mid-2020s. These battery storage options have the potential to provide solutions for the transmission and distribution systems, while simultaneously providing benefits to the generation resource portfolio. Overall, this plan adds 4,300 MW of CC and CT gas capacity beginning in the winter of 2029 to ensure the utility can meet customer load demand.

PORTFOLIO B (BASE CASE WITH CARBON POLICY)

This portfolio assumes the same base planning assumptions as the previous case but is developed with the IRP's base carbon tax policy as a proxy for future carbon legislation. This case adds 3,100 MW of natural gas capacity and pushes the DEC first need from winter of 2029 to winter of 2030. While less natural gas generation is built in the plan, renewable resources begin to be economically selected to meet demand. This plan selects 2,000 MW of incremental solar and solar plus storage than included in the base forecast and in the Base Case without Carbon Policy. This plan also begins to incorporate onshore central Carolinas wind, adding 150 MW in the last year of the planning horizon. These changes are a direct result of the carbon tax, which increases prices on carbon-intense resources like coal. The inclusion of the carbon tax in the development of this case clearly changes the resource selection, favoring more carbon free resources to meet the Company's energy needs.

PORTFOLIO C (EARLIEST PRACTICABLE COAL RETIREMENTS)

This portfolio focuses on DEC's ability to retire or cease burning coal at its existing coal units as early as practicable. Several factors were considered in the establishment of these retirement dates and are discussed in detail in Appendix A. The earliest practicable retirement analysis resulted in the acceleration of Marshall station from 2035 in the Base Cases to 2028 and Belews Creek from outside the IRP planning window to 2029. Cliffside 5's retirement date remains the same as the most economic retirement date at the end of 2025. On the other hand, Cliffside 6 ceases to burn coal by the end of 2029, but continues to provide flexibility and reliability as a natural gas-burning unit through the IRP study period. Part of the analysis for earliest practicable retirement dates requires construction and transmission upgrades and interconnection costs for replacement generation. Additionally, the retirement of the coal units was expedited by leveraging existing infrastructure to eliminate the need for transmission upgrades and/or new gas pipelines, as would be required at new replacement generation sites. Replacing over 6,800 MW of coal capacity requires extensive firm capacity additions to the DEC system. As such, this plan results in the acceleration of CT and CC capacity additions from later in the plan and outside the planning horizon to coincide with the coal retirements in order to capitalize on the existing gas and transmission infrastructure at the retiring coal sites. Further, additional transmission upgrades are avoided by siting replacement gas generation at the Marshall and Belews Creek stations. As with the Base Case with Carbon Policy scenario, this case also adds nearly 5,000 MW of solar and solar plus storage to replace retiring coal generation in order to meet DEC's future energy and capacity needs.

PORTFOLIO D (70% CO_2 REDUCTIONS: HIGH WIND)

This portfolio outlines a pathway for the Carolinas combined system to achieve 70% CO_2 reductions, from a 2005 baseline, by tapping into wind resources off the coast of the Carolinas. This plan leverages high energy efficiency and demand response projections, as well as high penetration renewables forecasts with increased solar annual integration limits. The combination of these resources further reduces carbon by adding 7,500 total MW of solar and solar plus storage.

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Additionally, 1,500 MW of land-based wind, from both central Carolinas and midcontinental U.S. is included. This portfolio also utilizes the earliest practicable retirement dates as established in Portfolio C with the associated replacement capacity to enable those retirements. It is worth noting that even with assumptions of high EE, DR, and renewables, combined with accelerated coal retirements do not get the combined system to 70% CO_2 reductions by 2030. In order to reach 70%, the Company adds 1,200 MW of offshore wind into the DEC system for the winter peak of 2030. For a long lead time infrastructure project such as this, the retirements of one of the Belews Creek units is delayed from 2029 to 2030 to maintain planning reserve capacity until the offshore wind can be operational.

PORTFOLIO E (70% CO_2 REDUCTION: HIGH SMR)

This portfolio outlines a pathway for the Carolinas combined system to achieve 70% CO_2 reductions, from a 2005 baseline, by deploying advanced nuclear technologies by the end of this decade. This plan also leverages high energy efficiency and demand response projections as well as high penetration renewables forecasts with increased solar annual integration limits. The combination of these inputs further reduces carbon by adding 7,500 total MW of solar and solar plus storage. As in Portfolio D, 1,500 MW of land-based wind, from both central Carolinas and midcontinental U.S. is included. This portfolio also utilizes the earliest practicable retirement dates as established in Portfolio C with the associated replacement capacity to enable those retirements. Again, it is worth noting that even with assumptions of high EE, DR, and renewables, combined with accelerated coal retirements do not get the combined system to 70% CO_2 reductions by 2030. In order to reach 70%, a 684 MW small modular nuclear reactor plant[1] is added to the DEC system at the beginning of 2030. For a long lead time infrastructure project such as this, the retirements of one of the Belews Creek units was delayed from 2028 to 2030 to maintain planning reserve capacity until the SMR can be operational.

PORTFOLIO F (NO NEW GAS GENERATION)

This portfolio addresses growing interest from stakeholders and Environmental, Social and Governance (ESG) investors to understand the impacts of transitioning the current DEC portfolio to a

[1] As described in Appendix A, the first full-scale, commercial SMR project is slated for completion at the start of the next decade which is the same time period as the plant in this scenario. To complete a project of this magnitude would require a high level of coordination between state and federal regulators, and even with that assumption, the timeline is still challenged based on the current licensing and construction timeline required to bring this technology to DEC.

net-zero carbon portfolio by 2050, without the deployment of new gas generation. Because the earliest practicable coal retirement dates are predicated on replacement with gas generation at some of the retiring coal sites, Portfolio F uses to the most economic coal retirement dates as utilized in the Base Cases. To minimize costs to customers, without the ability to build gas, high EE and DR projections as well as, high penetration renewables forecasts combined with increased solar annual integration limits are included in this plan. With the later retirement dates, and aided by the high forecasts of EE, DR and renewables, a capacity need does not appear in DEC until 2035 when Marshall station is retired. This energy and capacity need created by the retirement of Marshall station is met with Pumped Storage hydro and new Nuclear SMRs. As with portfolios D and E, significant intermittent generation increases the value of energy storage, which allows the capacity need to be met, in part, by adding 1,600 MW of pumped storage hydro capacity. The remainder of the capacity need is met with the deployment of a new small modular nuclear plant, providing 684 MW of firm, flexible capacity. With its modular design and ability to adjust output based on demand needs, this non-gas generation source can provide the necessary reliability and flexibility needed by the DEC system. Additionally, this plan adds 7,500 MW of solar and solar plus storage and 1,500 MW of land-based wind from both central Carolinas and mid-continental U.S.

PORTFOLIO ANALYSIS

The six portfolios developed from the Base Case and Portfolio Development and Sensitivity phase and informed by the Base Case sensitivity analysis, were evaluated in more detail utilizing an hourly production cost model under a matrix of nine carbon and fuel cost scenarios. The results of these hourly production cost model runs were paired with the accompanying capital costs and analyzed focusing on the trade-offs between cost, carbon reductions, and dependency on technological and policy advancements. Table 12-A below illustrates the scenario matrix, in which each portfolio was tested.

TABLE 12-A

SCENARIO MATRIX FOR PORTFOLIO ANALYSIS

	NO CO_2	BASE CO_2	HIGH CO_2
Low Fuel			
Base Fuel			
High Fuel			

Table 12-B details the results of the PVRR analysis under the varying carbon and fuel scenarios with the cost of the carbon tax excluded, while Table 12-C provides the same results but includes the cost of a carbon tax.

TABLE 12-B

SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, EXCLUDING THE EXPLICIT COST OF CARBON (2020 DOLLARS IN BILLIONS)

	BASE PLANNING WITHOUT CARBON POLICY	BASE PLANNING WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO_2-High Fuel	$51.5	$52.3	$52.5	$60.3	$58.0	$60.4
High CO_2-Base Fuel	$46.2	$47.5	$47.1	$56.3	$53.9	$56.5
High CO_2-Low Fuel	$42.4	$43.9	$43.5	$53.4	$51.1	$53.8
Base CO_2-High Fuel	$50.6	$51.2	$52.2	$60.1	$57.6	$59.8
Base CO_2-Base Fuel	$45.8	$46.8	$46.8	$56.1	$53.6	$56.0
Base CO_2-Low Fuel	$42.0	$43.4	$43.1	$53.2	$50.7	$53.2
No CO_2-High Fuel	$49.3	$49.4	$51.2	$59.5	$56.6	$58.3
No CO_2-Base Fuel	$44.4	$44.9	$45.8	$55.5	$52.6	$54.6
No CO_2-Low Fuel	$40.8	$41.6	$42.1	$52.7	$49.7	$51.7
Min	$40.8	$41.6	$42.1	$52.7	$49.7	$51.7
Median	$45.8	$46.8	$46.8	$56.1	$53.6	$56.0
Max	$51.5	$52.3	$52.5	$60.3	$58.0	$60.4

Corrected 11.06.2020

TABLE 12-C

SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, INCLUDING THE EXPLICIT COST OF CARBON (2020 DOLLARS IN BILLION)

	BASE PLANNING WITHOUT CARBON POLICY	BASE PLANNING WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO_2-High Fuel	$65.9	$64.0	$63.8	$68.3	$65.4	$68.4
High CO_2-Base Fuel	$59.8	$58.5	$58.3	$64.2	$61.3	$64.0
High CO_2-Low Fuel	$55.8	$54.9	$54.7	$61.3	$58.4	$61.1
Base CO_2-High Fuel	$61.8	$60.4	$60.5	$66.0	$63.1	$65.9
Base CO_2-Base Fuel	$55.9	$55.1	$55.0	$61.9	$59.0	$61.6
Base C_O2-Low Fuel	$51.9	$51.4	$51.4	$59.1	$56.2	$58.7
No CO_2-High Fuel	$49.3	$49.4	$51.2	$59.5	$56.6	$58.3
No CO_2-Base Fuel	$44.4	$44.9	$45.8	$55.5	$52.6	$54.6
No CO_2-Low Fuel	$40.8	$41.6	$42.1	$52.7	$49.7	$51.7
Min	$40.8	$41.6	$42.1	$52.7	$49.7	$51.7
Median	$55.8	$54.9	$54.7	$61.3	$58.4	$61.1
Max	$65.9	$64.0	$63.8	$68.3	$65.4	$68.4

BASE CASE WITH CARBON POLICY

Each of the alternative portfolios provides insight on strategies and advancements necessary to further evaluate carbon reductions and cost trade-offs. However, for planning purposes, Duke Energy considers the least cost, reliable cases as the Base Case with Carbon Policy and Base Case without Carbon Policy portfolios. These least cost portfolios meet the current IRP rules and regulations currently in place in NC and SC. If a carbon constrained future is either delayed or is more restrictive than base assumptions, or other variables, such as fuel price and capital costs change significantly from the base assumptions, the selected carbon constrained portfolio remains adequately robust to provide value in those futures. Another factor that is considered when selecting the base portfolio is the likelihood that the selected portfolio can be executed as presented.

Portfolio B, Base Case with Carbon Policy, is presented below and includes the addition of a diverse compilation of resources including CCs, CTs, battery storage, EE, DSM and significant amounts of solar, solar plus storage and wind. These resources are selected in conjunction with existing nuclear, natural gas, expected renewable projections and other assets already on the DEC system. This portfolio also enables the Company to lower carbon emissions under a range of future scenarios at a lower cost than most other scenarios.

Finally, the Base Case with Carbon Policy portfolio was developed utilizing consistent assumptions and analytic methods between DEC and DEP, where appropriate. This case does not consider the sharing of capacity between DEC and DEP. However, the Base Case incorporates the JDA between DEC and DEP, which represents a non-firm energy only commitment between the Companies. A Joint Planning Case that begins to explore the potential for DEC and DEP to share firm capacity was also developed and is discussed in Appendix A.

The Load and Resource Balance graph shown in Figure 12-E illustrates the resource needs required for DEC to meet its load obligation inclusive of a required 17% reserve margin. Existing generating resources, designated and expected resource additions and EE/DSM resources do not meet the required load and reserve margin beginning in 2030. As a result, the Base Case with Carbon Policy plan is presented to meet this resource gap.

FIGURE 12-E

DEC BASE CASE WITH CARBON POLICY LOAD RESOURCE BALANCE (WINTER)

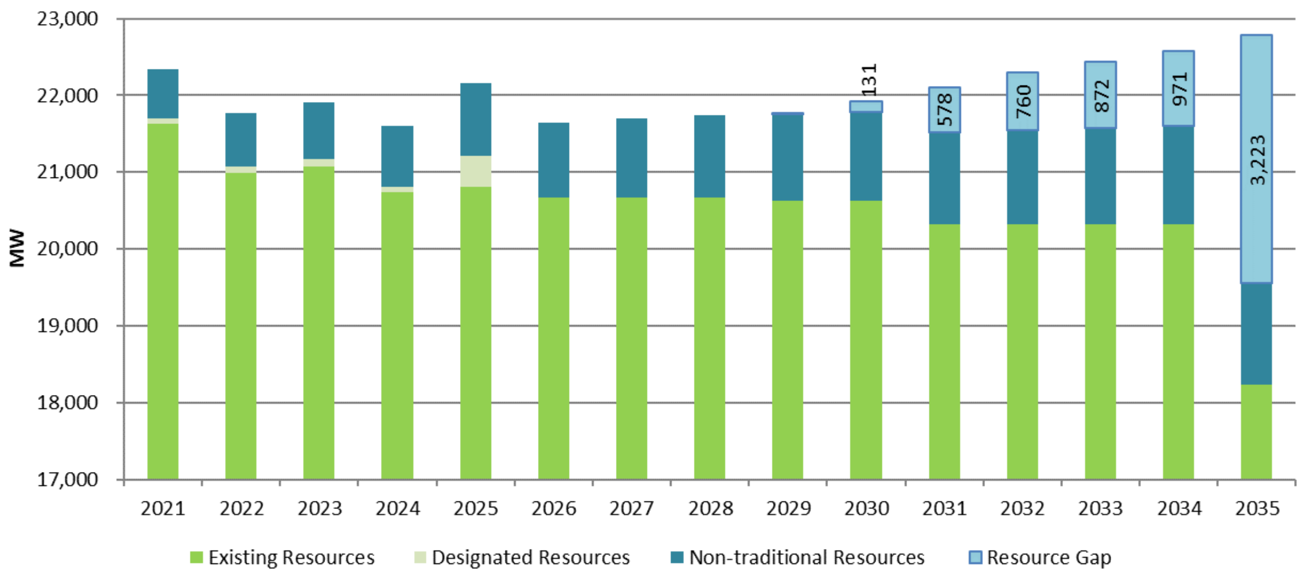

TABLE 12-D

CUMULATIVE RESOURCE ADDITIONS TO MEET WINTER LOAD OBLIGATION AND RESERVE MARGIN (MW)

YEAR	2021	2022	2023	2024	2025	2026	2027	2028
Resource Need	0	0	0	0	0	0	0	0

YEAR	2029	2030	2031	2032	2033	2034	2035
Resource Need	0	131	578	760	872	971	3,223

Tables 12-E and 12-F present the Load, Capacity and Reserves (LCR) tables for the Base Case with Carbon Policy analysis that was completed for DEC's 2020 IRP.

TABLE 12-E

BASE CASE WITH CARBON POLICY LOAD, CAPACITY AND RESERVES TABLE - WINTER

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Load Forecast																
1	DEC System Winter Peak	17,795	17,933	18,042	18,195	18,334	18,493	18,607	18,790	18,933	19,074	19,226	19,393	19,502	19,605	19,752
2	Catawba Owner Backstand - NCEMC	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
3	Cumulative New EE Programs	(70)	(129)	(183)	(233)	(303)	(346)	(382)	(410)	(430)	(437)	(436)	(431)	(421)	(405)	(377)
4	**Adjusted Duke System Peak**	**17,823**	**17,903**	**17,957**	**18,061**	**18,130**	**18,246**	**18,324**	**18,478**	**18,601**	**18,736**	**18,889**	**19,061**	**19,180**	**19,298**	**19,473**
Existing and Designated Resources																
5	Generating Capacity	21,447	21,518	20,900	20,995	20,634	21,036	20,490	20,490	20,490	20,490	20,490	20,317	20,317	20,317	20,317
6	Designated Additions / Uprates	71	86	95	65	402										
7	Retirements / Derates	-	(704)	-	(426)	-	(546)	-	-	-	-	(173)	-	-	-	(2,078)
8	**Cumulative Generating Capacity**	**21,518**	**20,900**	**20,995**	**20,634**	**21,036**	**20,490**	**20,490**	**20,490**	**20,490**	**20,490**	**20,317**	**20,317**	**20,317**	**20,317**	**18,239**
Purchase Contracts																
9	**Cumulative Purchase Contracts**	**212**	**210**	**186**	**189**	**190**	**186**	**188**	**187**	**150**	**150**	**20**	**11**	**11**	**10**	**10**
	Non-Compliance Renewable Purchases	37	40	17	18	19	13	13	13	12	12	12	11	11	10	10
	Non-Renewables Purchases	176	170	169	171	171	173	174	174	137	138	8	-	-	-	-
Undesignated Future Resources																
10	Nuclear															
11	Combined Cycle															1,224
12	Combustion Turbine										457	457				913
13	Solar					1	1	1	1	20	20	20	39	39	39	39
14	Wind															50
15	Battery															
Renewables																
16	**Cumulative Renewables Capacity**	**103**	**115**	**109**	**118**	**105**	**108**	**139**	**164**	**213**	**247**	**276**	**315**	**353**	**407**	**504**
	Renewables w/o Storage	103	91	81	83	62	59	60	55	56	53	45	28	19	17	17
	Solar w/ Storage (Solar Component)	-	1	1	2	2	2	3	5	6	6	7	7	7	7	7
	Solar w/ Storage (Storage Component)	-	23	27	34	40	45	73	101	129	146	163	180	188	205	214
17	**Combined Heat & Power**	**16**	**30**	**30**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
18	**Grid-connected Energy Storage**	**9**	**20**	**25**	**25**	**25**	**25**	**25**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
19	**Cumulative Production Capacity**	**21,859**	**21,300**	**21,421**	**21,096**	**21,511**	**20,989**	**21,047**	**21,070**	**21,083**	**21,574**	**21,756**	**21,787**	**21,825**	**21,877**	**22,033**
Demand Side Management (DSM)																
20	**Cumulative DSM Capacity**	**478**	**467**	**468**	**470**	**473**	**476**	**484**	**497**	**513**	**534**	**558**	**585**	**611**	**635**	**656**
21	**IVVC Peak Shaving**	**-**	**-**	**17**	**34**	**173**	**174**	**176**	**177**	**179**	**180**	**182**	**184**	**185**	**187**	**189**
22	**Cumulative Capacity w/ DSM**	**22,337**	**21,767**	**21,905**	**21,600**	**22,157**	**21,639**	**21,707**	**21,744**	**21,775**	**22,288**	**22,497**	**22,555**	**22,621**	**22,700**	**22,878**
Reserves w/ DSM																
23	Generating Reserves	4,513	3,865	3,948	3,539	4,027	3,392	3,383	3,266	3,174	3,553	3,608	3,494	3,441	3,402	3,405
24	**% Reserve Margin**	**25.3%**	**21.6%**	**22.0%**	**19.6%**	**22.2%**	**18.6%**	**18.5%**	**17.7%**	**17.1%**	**19.0%**	**19.1%**	**18.3%**	**17.9%**	**17.6%**	**17.5%**

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TABLE 12-F:

BASE CASE WITH CARBON POLICY LOAD, CAPACITY AND RESERVES TABLE – SUMMER

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Load Forecast																
1	DEC System Winter Peak	17,795	17,933	18,042	18,195	18,334	18,493	18,607	18,790	18,933	19,074	19,226	19,393	19,502	19,605	19,752
2	Catawba Owner Backstand - NCEMC	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
3	Cumulative New EE Programs	(70)	(129)	(183)	(233)	(303)	(346)	(382)	(410)	(430)	(437)	(436)	(431)	(421)	(405)	(377)
4	**Adjusted Duke System Peak**	**17,823**	**17,903**	**17,957**	**18,061**	**18,130**	**18,246**	**18,324**	**18,478**	**18,601**	**18,736**	**18,889**	**19,061**	**19,180**	**19,298**	**19,473**
Existing and Designated Resources																
5	Generating Capacity	21,447	21,518	20,900	20,995	20,634	21,036	20,490	20,490	20,490	20,490	20,490	20,317	20,317	20,317	20,317
6	Designated Additions / Uprates	71	86	95	65	402										
7	Retirements / Derates	-	(704)	-	(426)	-	(546)	-	-	-	-	(173)	-	-	-	(2,078)
8	**Cumulative Generating Capacity**	**21,518**	**20,900**	**20,995**	**20,634**	**21,036**	**20,490**	**20,490**	**20,490**	**20,490**	**20,490**	**20,317**	**20,317**	**20,317**	**20,317**	**18,239**
Purchase Contracts																
9	**Cumulative Purchase Contracts**	**212**	**210**	**186**	**189**	**190**	**186**	**188**	**187**	**150**	**150**	**20**	**11**	**11**	**10**	**10**
	Non-Compliance Renewable Purchases	37	40	17	18	19	13	13	13	12	12	12	11	11	10	10
	Non-Renewables Purchases	176	170	169	171	171	173	174	174	137	138	8	-	-	-	-
Undesignated Future Resources																
10	Nuclear															
11	Combined Cycle															1,224
12	Combustion Turbine										457	457				913
13	Solar					1	1	1	1	20	20	20	39	39	39	39
14	Wind															50
15	Battery															
Renewables																
16	**Cumulative Renewables Capacity**	**103**	**115**	**109**	**118**	**105**	**108**	**139**	**164**	**213**	**247**	**276**	**315**	**353**	**407**	**504**
	Renewables w/o Storage	103	91	81	83	62	59	60	55	56	53	45	28	19	17	17
	Solar w/ Storage (Solar Component)	-	1	1	2	2	2	3	5	6	6	7	7	7	7	7
	Solar w/ Storage (Storage Component)	-	23	27	34	40	45	73	101	129	146	163	180	188	205	214
17	**Combined Heat & Power**	**16**	**30**	**30**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
18	**Grid-connected Energy Storage**	**9**	**20**	**25**	**25**	**25**	**25**	**25**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
19	**Cumulative Production Capacity**	**21,859**	**21,300**	**21,421**	**21,096**	**21,511**	**20,989**	**21,047**	**21,070**	**21,083**	**21,574**	**21,756**	**21,787**	**21,825**	**21,877**	**22,033**
Demand Side Management (DSM)																
20	**Cumulative DSM Capacity**	**478**	**467**	**468**	**470**	**473**	**476**	**484**	**497**	**513**	**534**	**558**	**585**	**611**	**635**	**656**
21	**IVVC Peak Shaving**	**-**	**-**	**17**	**34**	**173**	**174**	**176**	**177**	**179**	**180**	**182**	**184**	**185**	**187**	**189**
22	**Cumulative Capacity w/ DSM**	**22,337**	**21,767**	**21,905**	**21,600**	**22,157**	**21,639**	**21,707**	**21,744**	**21,775**	**22,288**	**22,497**	**22,555**	**22,621**	**22,700**	**22,878**
Reserves w/ DSM																
23	Generating Reserves	4,513	3,865	3,948	3,539	4,027	3,392	3,383	3,266	3,174	3,553	3,608	3,494	3,441	3,402	3,405
24	**% Reserve Margin**	**25.3%**	**21.6%**	**22.0%**	**19.6%**	**22.2%**	**18.6%**	**18.5%**	**17.7%**	**17.1%**	**19.0%**	**19.1%**	**18.3%**	**17.9%**	**17.6%**	**17.5%**

TABLE 12-G

DEC - ASSUMPTIONS OF LOAD, CAPACITY, AND RESERVES TABLES

The following notes are numbered to match the line numbers on the Winter Projections of Load, Capacity, and Reserves tables. All values are MW (winter ratings) except where shown as a percent.

LINE ITEM	LINE INCLUSION[2]
1.	Peak demand for the Duke Energy Carolinas System as defined in Chapter 3 and Appendix C.
2.	Firm Catawba backstand for NCEMC. (579 MW * 17% RM) = 98 MW [3]
3.	Cumulative new energy efficiency and conservation programs (does not include demand response programs).
4.	Peak load adjusted for firm sales, NCEMC backstand and cumulative energy efficiency.
5.	Existing generating capacity reflecting the impacts of designated additions, planned uprates, retirements and derates as of January 1, 2020.
	Includes 103 MW Nantahala hydro capacity.
	Includes only DEC portion of Catawba Nuclear Station capacity.
	Includes Lee CC capacity of 683 MW, which is net of NCEMC ownership of 100 MW.
6.	Designated Capacity Additions
	Bad Creek Runner upgrades (65 MW per unit deployed in years 2021-2024).
	Lincoln CT 17 of 402 MW in 2025.
	Nuclear uprates: Oconee 1-3; 15 MW per unit deployed in years 2022-2023. Catawba 1 and 2; 6 MW per unit deployed in years 2021-2022.
7.	Estimated retirement dates for planning that represent most economical retirement date for coal units as determined in Coal Retirement Analysis discussed in Chapter 11. Other units represent estimated retirement dates based on the depreciation study approved in the most recent DEC rate case: Allen 2-4 (704 MW): December 2021 Allen 1 and 5 (426 MW): December 2023 Cliffside 5 (546 MW): December 2025 Marshall 1-4 (2,078 MW): December 2034 Lee 3 NG Boiler (173 MW): December 2030
	All nuclear units are assumed to have subsequent license renewal at the end of the current license.
	All hydro facilities are assumed to operate through the planning horizon.
	All retirement dates are subject to review on an ongoing basis. Dates used in the 2020 IRP are for planning purposes only, unless the unit is already planned for retirement.
8.	Sum of lines 5 through 7.

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

[3] NCEMC load was excluded in the 2020 load forecast per Commission order and as such, the NCEMC capacity was also removed from the total DEC generating assets. DEC is still responsible for backstanding the NCEMC capacity.

LINE ITEM	LINE INCLUSION
9.	Cumulative Purchase Contracts from traditional resources and renewable energy resources not used for NCREPS and NC HB 589 compliance. This is the sum of the next two lines.
	Non-Compliance Renewable Purchases includes purchases from renewable energy resources for which DEC does not own the REC.
	Non-Renewables Purchases are those purchases made from traditional generating resources.
10.	New nuclear resources economically selected to meet load and minimum planning reserve margin. No nuclear resources were selected in the Base Case with Carbon Policy in this IRP.
11.	New combined cycle resources economically selected to meet load and minimum planning reserve margin. Addition of 1,224 MW of combined cycle capacity online December 2034.
12.	New combustion turbine resources economically selected to meet load and minimum planning reserve margin. The case presented has the addition of the following CTs: 457 MW CT in December 2029 457 MW CT in December 2030 913 MW CTs in December 2034
13.	New solar resources economically selected to meet load and minimum planning reserve margin. The value in the table represents the contribution to peak of the selected solar facilities. (1% for winter peak and 40% for total solar < 999 MW reducing to 10% for total solar >3,600 MW for summer peak; Solar + Storage is approximately 25% in both summer and winter). The case presented has the addition of the following solar resources: Solar Only: 0.75 MW (75 MW nameplate) in each year 2025 through 2031; 1.5 MW (150 MW nameplate) in each year 2032 through 2035. Solar + Storage: 19 MW (75 MW nameplate) in each year 2029 through 2031; 37.5 MW (150 MW nameplate) in each year 2032 through 2035.
14.	New wind resources economically selected to meet load and minimum planning reserve margin. The value in the table represents the contribution to peak of the selected wind facilities. (33% for winter peak 7% for summer peak). The case presented has the addition 150 MW of wind resources in December 2034.
15.	New battery storage resources economically selected to meet load and minimum planning reserve margin. No battery resources were selected for DEC in the Base Case with Carbon Policy in this IRP.
16.	Cumulative Renewable Energy Contracts and renewable energy resources used for NCREPS and NC HB589 compliance. This is the sum of the next three lines and the selected cumulative renewable resources in lines 13-15.
	Renewables w/o Storage includes projected purchases from solar energy resources not paired with storage.
	Solar w/ Storage (Solar Component) includes the solar component of projected solar energy resources paired with storage.
	Solar w/ Storage (Storage Component) includes the storage component of projected solar energy resources paired with storage.

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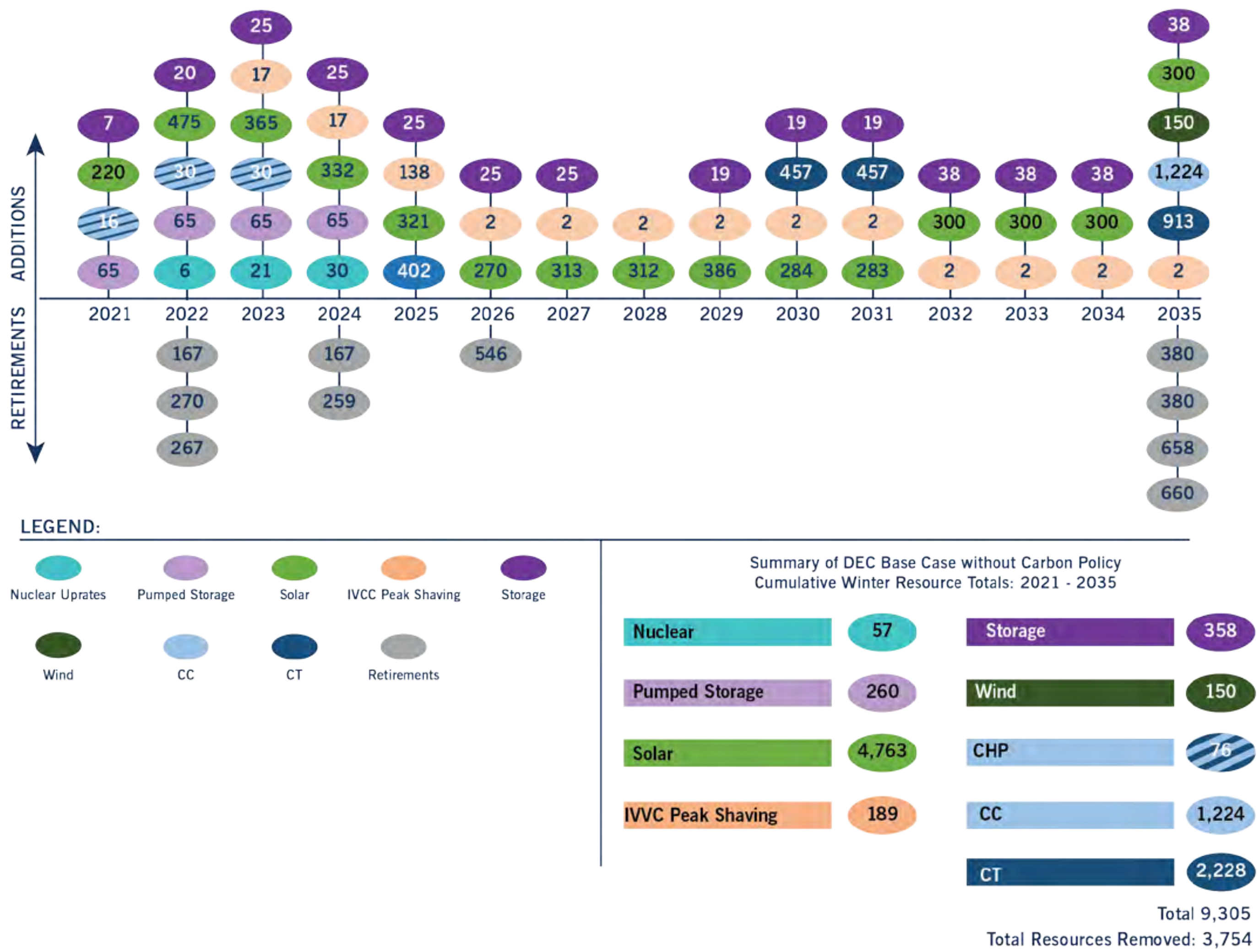
LINE ITEM	LINE INCLUSION
17.	Combined Heat and Power projects. This plan includes 15.7 MW Clemson CHP in 2021 and 30 MW CHP placeholders in 2022 and 2023.
18.	Addition of 154 MW of grid-tied energy storage over the years 2021 through 2027.
19.	Cumulative total of lines 8 through 18.
20.	Cumulative demand response programs including wholesale demand response.
21.	Cumulative capacity associated with peak shaving of IVVC program.
22.	Sum of lines 19 through 21.
23.	The difference between lines 22 and 4.
24.	Reserve Margin RM = (Cumulative Capacity-System Peak Demand)/System Peak Demand. Line 23 divided by Line 4. Minimum winter target planning reserve margin is 17%.

A graphical presentation of the Winter Base Case with Carbon Policy resource plan as represented in the above LCR table is shown below in Figure 12-F. This figure provides annual incremental capacity additions to the DEC system by technology type. Additionally, a summary of the total resources by technology is provided below the figure.

FIGURE 12-F

DEC BASE CASE WITH CARBON POLICY - ANNUAL ADDITIONS BY TECHNOLOGY

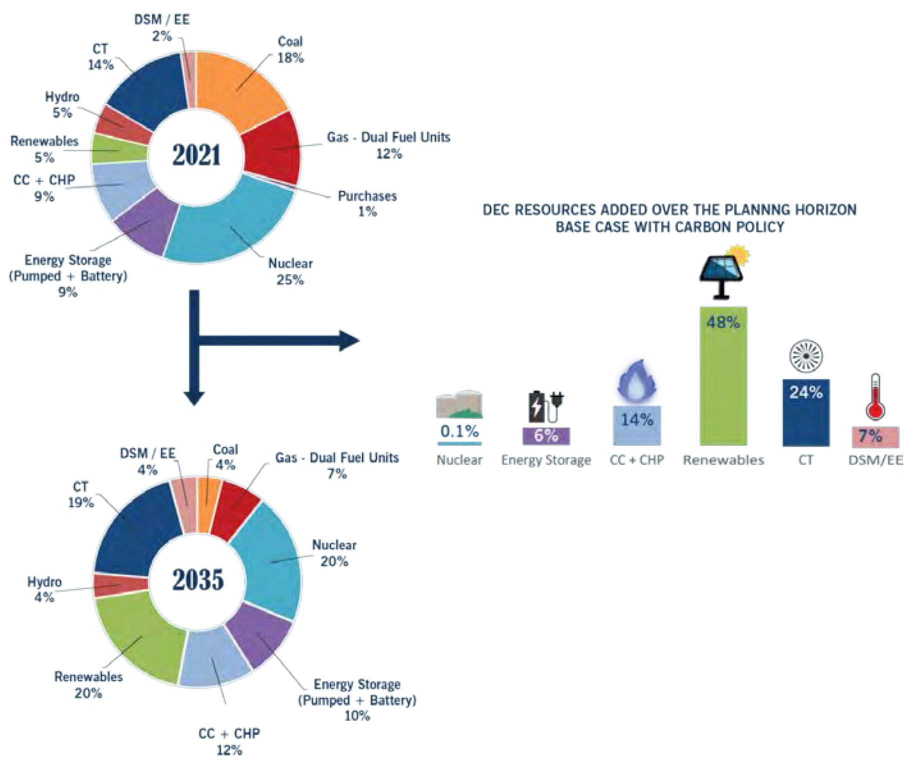


The following figures illustrate both the current and forecasted capacity for the DEC system, as projected by the Base Case with Carbon Policy. Figure 12-G depicts how the capacity mix for the DEC system changes with the passage of time. In 2035, the Base Case with Carbon Policy projects that DEC will have a substantial reduction in its reliance on coal and gas from steam units and a significantly higher reliance on renewable resources as compared to the current state. It is of particular note that nearly 50% of the new resources added over the study period are solar and wind resources.

As mentioned above, the Company's Base Case with Carbon Policy resources depicted in Figure 12-G below reflects a significant amount of growth in solar capacity with nameplate solar growing from 966 MW in 2021 to 4,016 MW by 2035. However, given that solar resources only contribute approximately 1% of nameplate capacity at the time of the Company's winter peak, solar capacity contribution to winter peak only grows from 10 MW in 2021 to 39 MW by 2035.

FIGURE 12-G

DEC CAPACITY OVER 15-YEAR STUDY PERIOD
BASE CASE WITH CARBON POLICY [4]

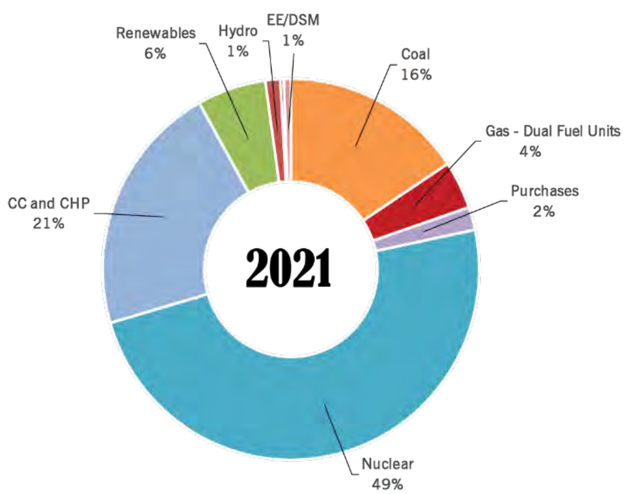


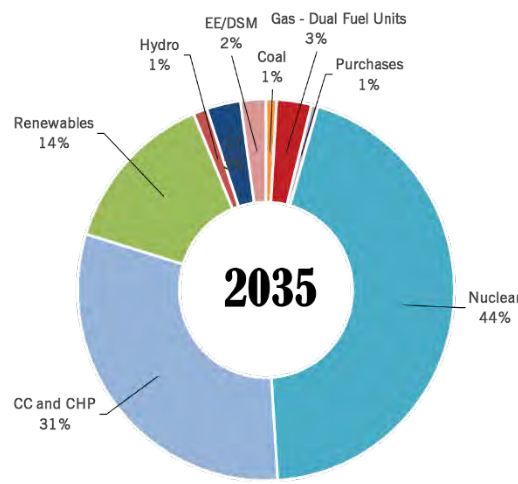
[4] All capacity based on winter ratings except Renewables and Energy Storage which are based on nameplate.

Figure 12-H represents the energy of both the DEC and DEP Base Cases with Carbon Policy over the IRP planning horizon. Due to the JDA, it is prudent to combine the energy of both utilities to develop a meaningful representation of energy for the Base Case with Carbon Policy. From 2021 to 2035, the figure shows that nuclear resources will continue to serve almost half of DEC and DEP's energy needs. Additionally, the figures display a substantial increase in the amount of energy served by carbon-free resources (solar, energy storage, solar plus storage, hydro and wind). Natural gas continues to remain an economical and reliable source of energy for the Companies, while the reliance on coal generation is reduced to 1%.

FIGURE 12-H

DEC AND DEP ENERGY OVER 15-YEAR STUDY PERIOD – BASE CASE WITH CARBON POLICY[5]





A detailed discussion of the assumptions, inputs and analytics used in the development of the Base Cases and other portfolios is contained in Appendix A. As noted, the further out in time planned additions or retirements are within the 2020 IRP, the greater the opportunity for input assumptions to change. Thus, resource allocation decisions at the end of the planning horizon have a greater possibility for change as compared to those earlier in the planning horizon.

[5] All capacity based on winter ratings except renewables and energy storage which are based on nameplate.

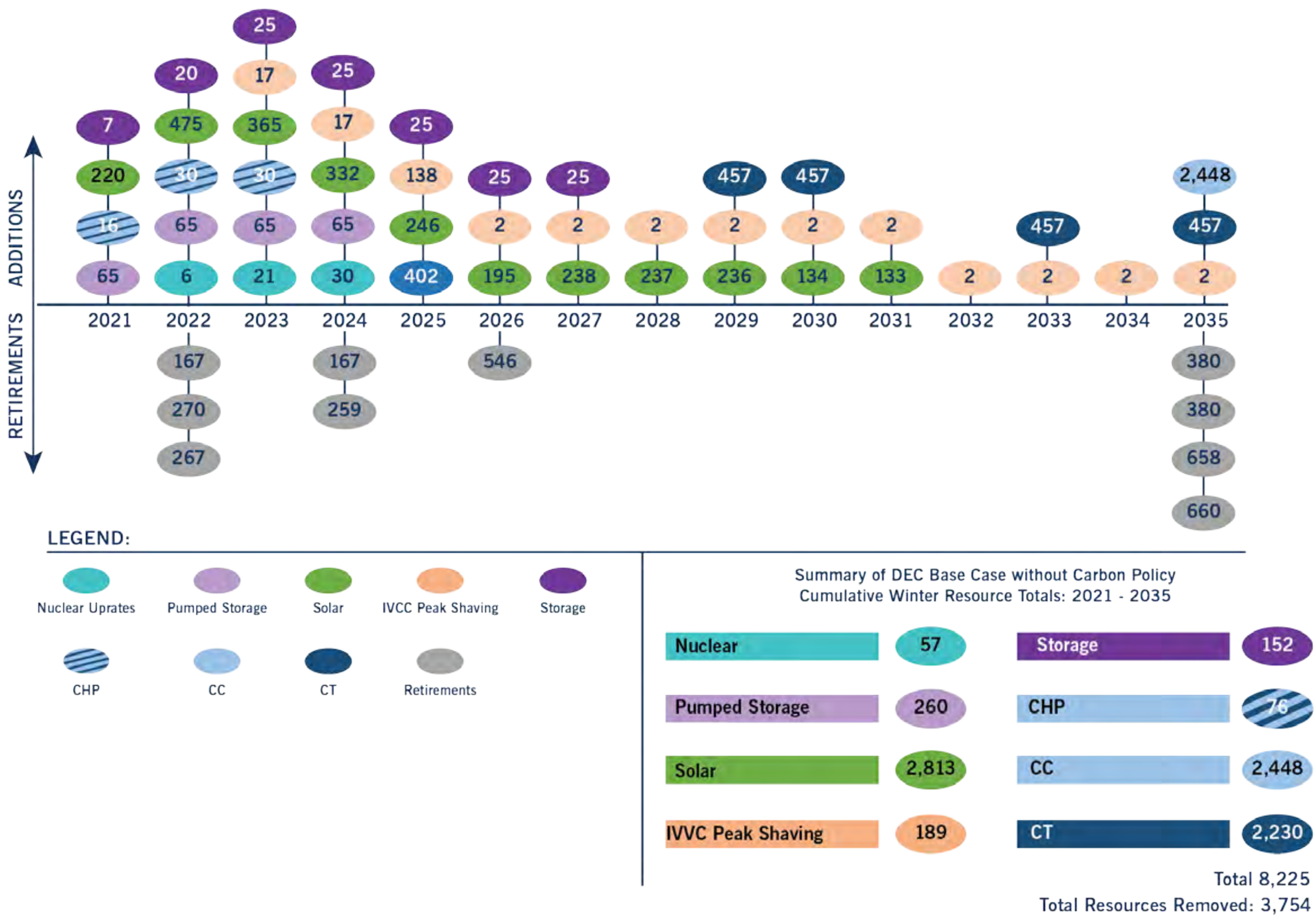
BASE CASE WITHOUT CARBON POLICY

While Duke Energy presents a base resource plan developed under a carbon constrained future, the Company also provides a Base Case without Carbon Policy expansion plan that reflects a future without CO_2 constraints. In DEC, this expansion plan is represented by Portfolio A or the Base Case without Carbon Policy. During the 15-year planning horizon, there is a significant shift toward CC technology as compared to the Base Case with Carbon Policy. Additionally, no incremental renewable resources were economically selected in this case.

A graphical presentation of the Winter Base Case without Carbon Policy resource plan is shown below in Figure 12-I. This figure provides annual incremental capacity additions to the DEC system by technology type for this case. Additionally, a summary of the total resources by technology is provided below the figure. Further details of the development of the Base Case without Carbon Policy may be found in Appendix A.

FIGURE 12-I

DEC BASE CASE WITHOUT CARBON POLICY ANNUAL ADDITIONS BY TECHNOLOGY



JOINT PLANNING CASE

As mentioned previously, a Joint Planning Case that explores the potential for DEC and DEP to share firm capacity between the Companies was also developed. The focus of this case is to illustrate the potential for the Utilities to collectively defer generation investment by utilizing each other's capacity when available and by jointly owning or purchasing new capacity additions. This case does not address the specific implementation methods or issues required to implement shared capacity.

Rather, this case illustrates the benefits of joint planning between DEC and DEP with the understanding that the actual execution of capacity sharing would require separate regulatory proceedings and approvals.

A discussion of the Joint Planning Case is provided in Appendix A.

13 DEC FIRST RESOURCE NEED

The IRP process provides a resource plan to most economically and reliably meet the projected load requirements and a reasonable reserve margin throughout the 15-year study period. In addition to load growth, planned unit retirements and expiring purchase power contracts contribute to the need for new generation resources.

The resources used to meet the load requirements fall into two categories: Designated and Undesignated. Designated resources are those resources that are in service, projects that have been granted a Certificate of Public Convenience and Necessity (CPCN) or Certificate of Environmental Compatibility and Public Convenience and Necessity (CECPCN), smaller capacity additions that are a result of unit uprates that are in the Companies' planning budget, firm market purchases over the duration of the signed contract or DSM/EE programs.

Undesignated resources include purchase power contracts that have not yet been executed and projected resources in the IRP that do not have a CPCN or CECPCN granted,

Additionally, firm market purchases, which include wholesale contracts, including renewable contracts, are assumed to end at the end of the currently contracted period. There is no guarantee that the counterparty will choose to sell, or the Company will agree to purchase its capacity after the contracted timeframe. Beyond the contract period the seller may elect to retire the resource or sell the output to an entity other than the Company. As such, contracted resources are deemed designated only for the duration of their legally enforceable contract.

Further, solar renewable contracts are broken down into three categories: Designated, Mandated and Undesignated. As discussed in Chapter 5, the definitions of each bucket are below:

FIGURE 13-A

CATEGORIES OF CONTRACTS

Only designated and mandated resources are considered when determining the first need for purposes of the development of standard offer avoided capacity rates. As such, a list of these resources for DEC is below:

- Designated and mandated renewable resources
- Nuclear uprates
- Bad Creek runner uprates
- Clemson CHP project
- Lincoln CT project
- Designated wholesale contracts
- DSM/EE programs

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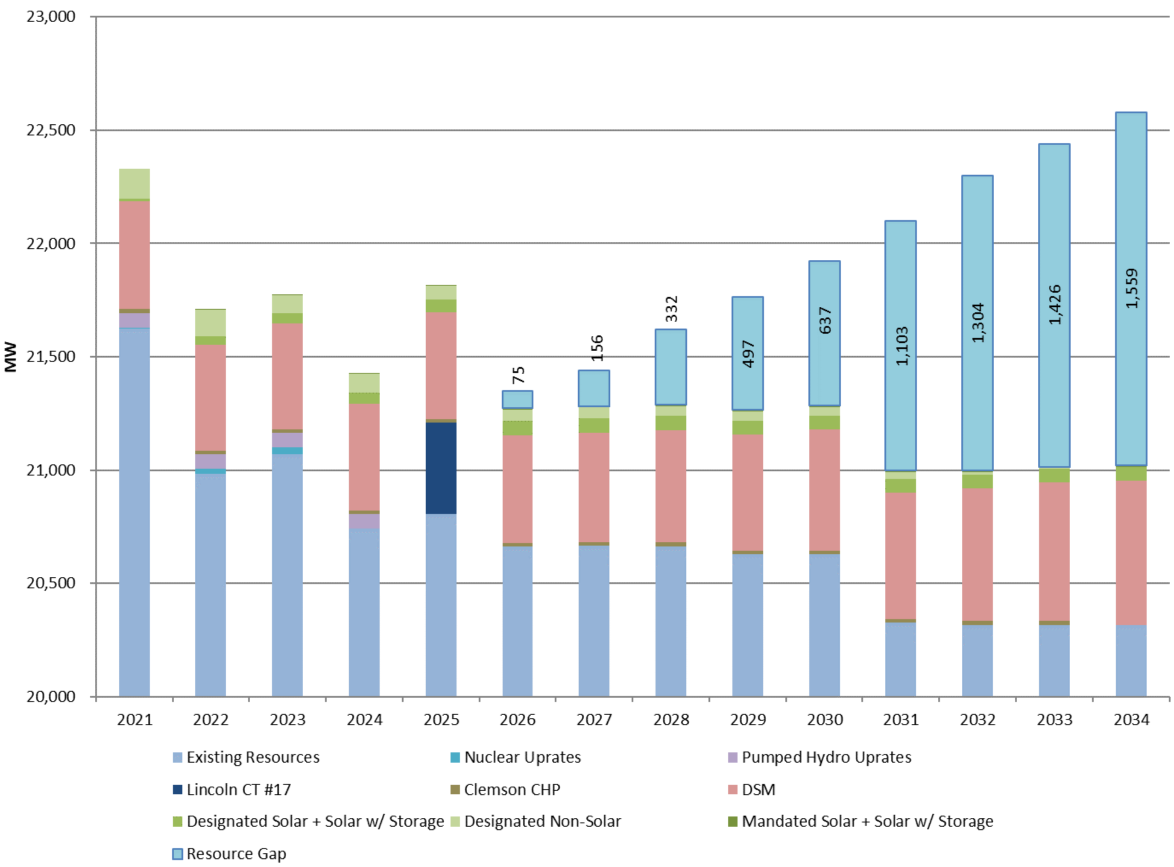
Including only the designated and mandated resources, Figure 13-B demonstrates the first need for DEC is in 2026. To the extent current contracts become executed and move from an undesignated to a designated resource, the timing of the first need will change accordingly.

FIGURE 13-B
LOAD RESOURCE BALANCE FOR DEC FIRST NEED



In the 2019 IRP, the first resource need for DEC was also determined to be in 2026. There has been no change to the first resource need in DEC.

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14 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:

ACCOMPLISHMENTS IN THE PAST YEAR

The following items were completed by DEP and DEC in the last year to support the development of the 2020 IRP:

COMPLETED STUDIES

As previously discussed in the Executive Summary, multiple studies have been completed in the previous year. The results of each of these studies were utilized in the development of the 2020 IRP. Table 14-A is a reproduction of the table presented in the Executive Summary.

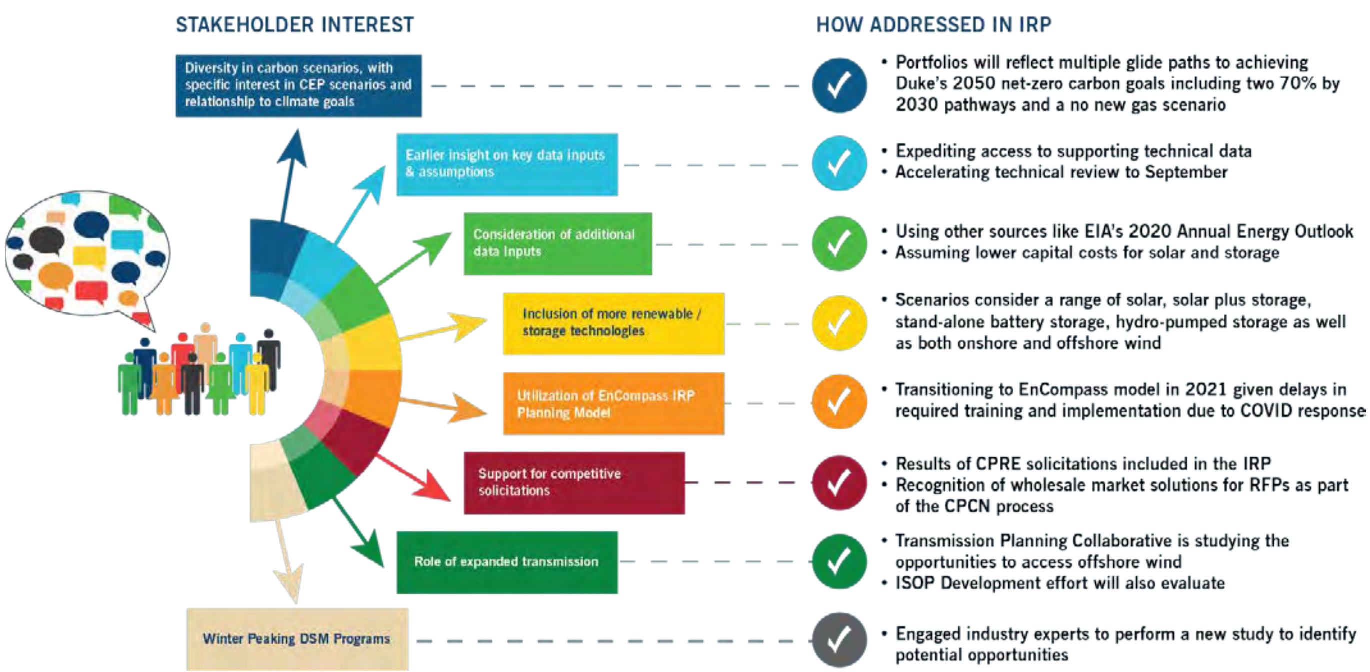
TABLE 14-A
COMPLETED STUDIES INFORMING THE 2020 IRP

STUDY	STUDY REQUIREMENTS
Economic Coal Retirements	• Analysis established the most economic coal unit retirement dates for the Base CO_2 and Base No CO_2 scenarios.
Earliest Practicable Coal Retirements	• Analysis established the earliest feasible coal unit retirement dates. Analysis set aside normal economic considerations and focused on procurement and construction timelines for replacement capacity in order to retire the coal units at the earliest attainable dates.
Resource Adequacy Study/ Reserve Margin Study	• Astrapé Consulting study evaluated reliability based on meeting the one day in ten years loss of load expectation (LOLE) metric.
Storage Effective Load Carrying Capability (ELCC) Study	• Astrapé Consulting study evaluated capacity value of storage under multiple conditions, including its contribution to winter peak and considerations with increasing levels of renewable penetration.
Energy Efficiency and Market Potential Study	• Nexant study evaluated market potential for energy efficiency and demand response initiatives.
Winter Specific DR and Rate Design Benchmarking Study	• Being conducted by Tierra Resource Consultants, Proctor Engineering Group, and Dunsky. Studies the integration of new rate designs and DSM technology with innovative program structures to drive winter peak focused reductions.

IMPLEMENTED COLLABORATIVE STAKEHOLDER ENGAGEMENT PROCESS

Duke Energy implemented an intentional process to collaborate with stakeholders to help shape the development of the 2020 IRP. Stakeholders in North Carolina and South Carolina provided recommendations in the areas of resource planning, carbon reduction, energy efficiency and demand response. 188 unique external stakeholder participants from across the Carolinas participated in this process. Figure 14-A provides a graphical representation of the intention of the stakeholder process, as presented in the Executive Summary.

FIGURE 14-A
STAKEHOLDER ENGAGEMENT



CONTINUED RELIANCE ON EE AND DSM RESOURCES

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

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

- Continue on-going collaborative work to develop and implement additional cost-effective EE and DSM products and services, such as: (1) adding new or expanding existing programs to include additional measures drawing on insights gained through the updated Market Potential

Study, (2) program modifications to account for changing market conditions and new measurement and verification (M&V) results and (3) other EE research and development pilots.

- Continue to seek additional DSM programs employing both rate-enabled and traditional equipment-based measures that will specifically provide load reduction benefits during winter peak situations.

- The Company undertook a detailed study to specifically examine the potential for additional winter demand-side peak savings through innovative rates initiatives combined with advanced demand response and load shifting programs that were outside of the MPS scope. The Company envisions working with stakeholders in the upcoming months and beyond to investigate and deploy, subject to regulatory approval, additional cost-effective programs identified through this effort. Over time as new programs/rate designs are approved and become established, the Company will gain additional insights into customer participation rates and peak savings potential and will reflect such findings in future forecasts.

CONTINUED FOCUS ON RENEWABLE ENERGY RESOURCES

DEC is committed to the addition of significant renewable generation into its resource portfolio. Over the next five years DEC is projecting to grow its renewable portfolio from 1,099 MW to 2,778 MW. Supporting policy such as SC Act 236, SC Act 62, NC REPS and NC HB 589 have all contributed to DEC's aggressive plans to grow its renewable resources. DEC is committed to meeting its targets for the SC DER Program and under HB 589, DEC and DEP are responsible for procuring renewable energy and capacity through a competitive procurement program. DEC/DEP have completed two solicitations under CPRE, resulting in 1,049 MW of nameplate solar expected in DEC. Planning for the next phase of CPRE activities is underway. These activities will be done in a manner that allows the Companies to continue to reliably and cost-effectively serve customers' future energy needs. The Companies, under the competitive procurement program, are required to procure energy and capacity from renewable energy facilities in an aggregate amount of up to 2,660 MW through request for proposals. Note that the connection of other transition MW can act to replace the required CPRE capacity. DEC and DEP plan to jointly implement the CPRE Program across the NC and SC service territories.

For further details regarding DEC's plans regarding renewable energy, refer to Chapter 5, Appendix E, and Attachments I and II.

INTEGRATION OF BATTERY STORAGE ON SYSTEM

The Company has begun investing in grid-connected storage systems, with plans for additional multiple grid connected storage systems. These systems will be dispersed throughout its North and South Carolina service territories that will be located on property owned by the Company or leased from its customers. These deployments will allow for a more complete evaluation of potential benefits to the distribution, transmission and generation system, while also providing actual operation and maintenance cost impacts of batteries deployed at a significant scale. Also, as directed by the NCUC, the Company has been working with stakeholders to assess challenges and develop recommendations to address challenges related to retrofit of existing solar facilities with energy storage. A report on this matter is expected to be filed in September 2020. Finally, as noted in the table of studies above, the Company engaged Astrapé Consulting to perform a study to assess the incremental change in Effective Load Carrying Capability of battery storage as more batteries are added to the system. This report is further described in Chapter 6, Appendix H and Attachment IV.

IVVC IMPLEMENTATION AS PART OF THE GRID IMPROVEMENT PLAN

Lastly, Integrated Voltage/VAR Control (IVVC) is part of the proposed Duke Energy Carolinas Grid Improvement Plan (GIP) and involves the coordinated control of distribution equipment in substations and on distribution lines to optimize voltages and power factors on the distribution grid.

Once the GIP is approved, which is expected by 2022, the IVVC program is expected to be fully implemented in DEC by 2025. A detailed discussion of IVVC may be found in Appendix D.

CONTINUE TO FIND OPPORTUNITIES TO ENHANCE EXISTING CLEAN RESOURCES

DEC is committed to continually looking for opportunities to improve and enhance its existing resources. DEC has committed to the replacement of the runners on each of its four Bad Creek pumped storage units. Each replacement is expected to gain approximately 65 MW of capacity. The first replacement is projected to be in 2020, available for the 2021 winter peak. The remaining units will be replaced at the rate of one per year for availability in the winter peaks from 2022 to 2024.

DEC is expecting capacity uprates to its existing nuclear units at Oconee and Catawba, due to upcoming projects at those sites. The uprates total 57 MW and are projected to occur from 2021 to 2023.

ADDITION OF CLEAN NATURAL GAS RESOURCES[1]

- The Company continues to consider advanced technology combined cycle and combustion turbine units as excellent options for a diversified, reliable portfolio required to meet future customer demand. The improving efficiency and reliability of CCs coupled with the lower carbon content and continued trend of lower prices for natural gas make these resources economically attractive, as well as very effective at enabling significant carbon reductions through accelerated economic coal retirements. As older units on the DEC system are retired, CC and CT units continue to play an important role in the Company's future diverse resource portfolio.

    - An advanced combustion turbine unit began extended commissioning at the Lincoln CT Plant in North Carolina in 2020. Testing is currently underway. The Company will take care, custody, and control of the completed 402 MW unit in 2024.
    - A 15.7 MW Combined Heat and Power project is now operational at Clemson University. The CHP project was completed in November 2019 and is included as a designated resource in this IRP. Additionally, placeholders for two additional CHP facilities are included in 2021 and 2022. Duke Energy will continue to explore and work with potential customers with continuous large thermal loads on additional regulated CHP offers. Updates to this process will be included in future IRPs.

A summarization of the capacity resource changes for the Base Plans in the 2020 IRP is shown in Table 14-B below. Capacity retirements and additions are presented as incremental values in the year in which the change impacts the winter peak. The values shown for renewable resources, EE, DSM and IVVC represent cumulative totals.

[1] Capacities represent winter ratings.

TABLE 14-B

DEC SHORT-TERM ACTION PLAN

				RENEWABLE RESOURCES (CUMULATIVE NAMEPLATE MW)				
YEAR	RETIREMENTS [6]	ADDITIONS [3]	SOLAR [4]	SOLAR WITH STORAGE [5]	BIOMASS / HYDRO	CUMULATIVE EE	DSM	IVVC [7]
2021		9 MW Energy Storage 6 MW Nuclear Uprate 65 MW Bad Creek Upgrade 16 MW Clemson CHP	966	0	132	70	478	0
2022	704 MW Allen 2-4	20 MW Energy Storage 21 MW Nuclear Uprates 65 MW Bad Creek Upgrade 30 MW CHP	1,327	115 w/ 25 Storage	118	129	467	0
2023		25 MW Energy Storage 30 MW Nuclear Uprates 65 MW Bad Creek Upgrade 30 MW CHP	1,673	134 w/ 30 Storage	81	183	468	17
2024	426 MW Allen 1 and 5	25 MW Energy Storage 65 MW Bad Creek Upgrade	1,976	163 w/ 37 Storage	81	233	470	34
2025		402 MW Lincoln CT Project 25 MW Energy Storage	2,268	192 w/ 45 Storage	59	303	473	173

(1) Capacities shown in winter ratings unless otherwise noted.
(2) Dates represent when the project impacts the winter peak.
(3) Energy storage is grid-tied storage and represents total usable MW.
(4) Capacity is shown in nameplate ratings and does not include solar coupled with energy storage.
(5) Solar coupled with storage; storage only charged from solar.
(6) Retirement dates reflect 'most economical' dates from the Coal Retirement Analysis.
(7) Integrated Volt Var Control represents cumulative impacts.

Corrected 11.06.2020

CONTINUE WITH PLAN FOR SUBSEQUENT LICENSE RENEWAL OF EXISTING NUCLEAR UNITS

In September 2019, Duke Energy announced its intent to pursue SLR for all eleven nuclear units in the operating fleet. The Oconee SLR application will be submitted first, in 2021. An SLR application takes approximately three years to prepare and approximately two years to be reviewed and approved. As information, Oconee's current licenses are set to expire in 2034 and 2035.

Continued Transition Toward Integrated System and Operations Planning:

As explained further in Chapter 15, the concept of ISOP remains on the path as described in the 2019 IRP filed in NC and SC. The Company continues to view this effort as an important and necessary evolution in electric utility planning processes. The Company remains committed to the goal of implementing the basic elements of ISOP in the 2022 IRPs for the Carolinas. This timeline is based on the Company's perspective that declining costs of distributed resources, including energy storage and advanced demand response options will increasingly create opportunities late in this decade and beyond to defer or potentially even avoid traditional "wires" upgrades and, in some cases, help to offset needs for building generation resources.

CONTINUED COMMITMENT TO MEETING THE COMPANY'S CARBON PLAN

As discussed throughout this IRP document, DEC is committed to meeting Duke Energy Corporation's Carbon Plan. All six of the key portfolios outlined in the Executive Summary keep Duke Energy on a trajectory to meet its near-term enterprise carbon reduction goal of at least 50% by 2030, and long-term goal of net-zero by 2050. See Chapter 16 for additional discussion on the net-zero carbon goal. As part of Duke Energy's long-standing commitment to carbon reductions, older coal and CT units have been retired and replaced with cleaner renewable energy resources and advanced CC and CT units. The overall effort includes the following elements:

- As of April 2015, Duke Energy Carolinas has no remaining older, un-scrubbed coal units in operation.[2]

[2] The ultimate timing of unit retirements can be influenced by factors changing the economics of continued unit operations. Such factors include changes in relative fuel prices, operations and maintenance costs and the costs associated with

- To date, DEC has retired approximately 1,700 MW of older coal generation since 2011.

- Allen unit retirements in YE2021 and YE2023 and the associated new South Point switchyard, which is necessary to allow for the retirement of all five Allen units, will bring economic value to customers and further the clean energy goals held by the Company and stakeholders. As with all unit retirement dates in the IRP, this is not a commitment to retire the Allen units on this timeline but rather contains the Company's most recent estimate of retirement economics at the time of this filing. Official retirement will require final management approval with final retirement dates contingent upon the finalization of the supporting switchyard project and other operational considerations. With the potential retirement of Allen Steam Station on the horizon, it is noteworthy that the facility has provided reliable energy to the Carolinas for over 60 years.

- Continue to investigate the future environmental control requirements and resulting operational impacts associated with existing and potential environmental regulations such as Mercury Air Toxics Standard (MATS), the Coal Combustion Residuals (CCR) rule, the Cross-State Air Pollution Rule (CSAPR), and any future federal or state carbon reduction policies.

WHOLESALE

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

- Over the next five years, DEC has a very small amount of contracts that expire under the current contract terms. The Company will determine the feasibility of obtaining additional purchased power arrangements in the future to economically meet customer demand.

REGULATORY

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

compliance of evolving environmental regulations. As such, unit retirement schedules are expected to change over time as market conditions change.

DEC REQUEST FOR PROPOSAL (RFP) ACTIVITY

SUPPLY-SIDE RFP ACTIVITY

Outside of renewable solicitations, no supply-side RFPs have been issued since the filing of DEC's last IRP.

COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY (CPRE)

Pursuant to N.C. Gen. Stat. § 62-110.8, DEC has completed the first RFP solicitation under the Competitive Procurement of Renewable Energy Program and is currently in the contracting phase for the second RFP. In summary, the final results from Tranche 1 and the initial results from Tranche 2 appear to have been successful, procuring approximately 1,049 MW of resources at prices below administratively-established avoided costs, pending Tranche 2 on-going contract negotiations. Details concerning the CPRE program can be found in the annual CPRE Program Plan filing, which is Attachment II to this document.

15 INTEGRATED SYSTEM & OPERATIONS PLANNING (ISOP)

The concept of ISOP remains on the path as described in the 2019 IRP filed in NC and SC. The Company continues to view this effort as an important and necessary evolution in electric utility planning processes to address the trends in technology development, declining cost projections for energy storage and renewable resources, and customer adoption of electric demand modifying resources such as roof-top solar and electric vehicles (EVs). The anticipated growth of Distributed Energy Resources (DERs) necessitates moving beyond the traditional distribution and transmission planning assumption of one-way power flows on the distribution system and analysis based on limited snapshots of peak or minimum system conditions. As the grid becomes more dynamic, analysis of the distribution and transmission systems will need to account for increasing variability of generation and two-way power flows on the distribution system, which requires significant changes to modeling inputs and tools. The Company remains committed to the goal of implementing the basic elements of ISOP in the 2022 IRPs for the Carolinas. This timeline is based on the Company's perspective that declining costs of distributed resources, including energy storage and advanced demand response options will increasingly create opportunities late in this decade and beyond to defer or potentially even avoid some traditional "wires" upgrades and, in some cases, help to offset needs for building generation resources.

The advancements in planning tools through the ISOP initiative also open new possibilities for analysis to help identify transmission and distribution infrastructure opportunities from a more holistic perspective. In the current regulatory paradigm, utilities provide first come, first serve access to resource developers and utility participants that request system interconnections where their projects seem best suited. This paradigm tends to result in the utility systems evolving incrementally based on the requests they receive, in the order received, in contrast with a system plan that could be developed reflecting the desired energy resource mix over the longer term. Over time, there may be the opportunity to evolve to a longer-term grid planning approach as contemplated here, but it is important to recognize that this type of transition would affect many stakeholders and would require constructive regulatory support to consider these changes. These ideas reflect some of the longer-term strategic concepts that are being considered in the development of the new ISOP advanced planning tools and processes.

DISTRIBUTION CIRCUIT LEVEL FORECASTING

Historically, distribution planners have used historical peak snapshots along with an expected growth factor to assess circuit capacity needs. To assess the potential for non-traditional solutions such as energy storage or other DERs, hourly time-series forecasts are needed at the circuit level to analyze the expected load profile, including how it could change over time as a function of residential, commercial or industrial growth, or adoption of net load modifiers such as energy efficiency, rooftop solar, and electric vehicles. This effort involves a significant time and resource commitment to gather the necessary input data and build the forecasting models required to support this extensive level of granular forecasting. Over the past year, the Company has developed models to enable derivation of hourly forecasts for the distribution circuits in the Carolinas covering a ten-year horizon. These models are currently in a cycle of validation and refinement, with the expectation to progressively roll the forecasts out to distribution planners throughout 2021 to support testing of the Advanced Distribution Planning toolset.

ADVANCED DISTRIBUTION PLANNING (ADP)

As noted above, distribution planners have traditionally analyzed historical peak snapshots. More dynamic grid conditions driven by distributed resources and circuit switching capability require more complex hourly power flow analysis to study the effects of DERs and assess the effectiveness of both traditional and non-traditional solutions (or combinations of solutions). Duke has continued its work with CYME, an industry leader in distribution modeling, to develop an ADP tool capable of performing these detailed analyses and supporting evaluation of both traditional and non-traditional solutions on the system. The development and testing effort over the past year has largely focused on automation and integration to make complex evaluation processes more efficient for the planners. The project remains on-track for the basic ADP functionality to be progressively rolled out to DEC and DEP distribution planners for testing and validation beginning in late 2020 and throughout 2021. Subsequent development efforts will focus on broadening the data available to planners, improving the efficiency of the modeling systems through integration and automation, and adding more robust capabilities such as multi-circuit analysis and combinations of traditional and non-traditional solutions, etc.

The new functionality of the ADP toolset will enable planners to evaluate DERs (including energy storage) as a potential solution for capacity needs and identify the most likely hourly patterns where potential new DERs would be needed to address local issues. These DER profiles could then be included as an input to transmission and generation planning processes to further assess potential value at the transmission and bulk generation levels. The growth in the scope and volume of the detailed data required to perform these new integrated planning studies is driving the need for much more coordination between planning groups and integration between the respective models across distribution, transmission, and generation planning.

While the ADP development effort is underway, the Company has also worked on developing screening processes to efficiently identify distribution upgrade needs that could potentially be deferred with non-traditional solutions. This process provides an opportunity to study a variety of potential energy storage use cases and better understand the steps that would be needed to perform a more detailed analysis for any candidates of interest that did appear. In this initial analysis of existing traditional distribution projects, 3% of the population was found to be suitable for further study, which is ongoing. It should be noted that the screening process at this stage uses relatively generous assumptions to avoid screening out a potential high value candidate prior to gaining experience and refining the process through detailed studies.

As part of the Company's broader industry engagements, the ISOP and ADP teams participated in a multi-utility collaborative study in the first half of 2020 led by the Smart Electric Power Alliance (SEPA) on Integrated Distribution Planning. The feedback the Company received in this forum along with review of SEPA's draft publication which should be released in the near future increases the Company's confidence in its approach to ADP.

INTEGRATION WITH TRANSMISSION PLANNING PROCESSES

To complement existing NERC Standard and FERC Order compliance-based Transmission Planning processes, the Company is developing new modeling capabilities for examining long term transmission needs and DER integration on the grid at an hourly granularity using some of the advanced features of an industry standard third-party DC power flow model. Accomplishing this additional level of detailed analysis requires extensive development work to integrate models and data sources and allow for hourly power flow analysis to complement the industry standard third-party AC power flow model used for transmission planning today. The DC power flow analysis is being developed for screening over broad time periods to help planners identify specific time periods and operating conditions that may warrant more detailed AC power flow analysis using the conventional transmission planning tools.

These enhanced new transmission modeling tools and processes will be used to support comprehensive assessments of transmission needs as the system evolves with coal plant retirements and significant growth of distributed energy resources. These studies, in concert with regional and interregional planning studies, will help planners find ways to optimize the use of existing grid capabilities and plan cost effective options to upgrade grid capabilities needed to support integration of the array of new resources necessary to meet the clean energy planning objectives. These new tools being developed and deployed as part of the ISOP program are critical to answering important questions about how the utility will integrate diverse energy resources to reliably serve customers in the future and how the utility will balance economic priorities in this transition.

Over the last year, the Company has also worked on developing screening processes to efficiently identify transmission upgrade needs that could potentially be deferred with non-traditional solutions. Going through this process also helps to build shared understanding among the team regarding potential energy storage use cases and the opportunities and challenges of adding value through multiple use cases. In this initial screening analysis of current transmission projects in early development, none were found to be both cost-effective and technically viable. While this result was expected in light of near-term energy storage costs, it should not be considered indicative of long-term opportunities. As noted in Chapter 6, the cost of energy storage is projected to decline by about 50% by 2030, which would significantly improve opportunities for non-traditional solutions.

ENHANCED RESOURCE PLANNING AND ISOP OPTIMIZATION

To successfully examine pathways to meet clean energy objectives in the manner envisioned in ISOP, it is critical to consider the mix of both centralized and distributed energy supply resources in use over the planning period and examine the interactions of the energy resources with the delivery systems to ensure that energy can be efficiently managed and delivered on the grid. Creation of this collaborative planning process with Distribution and Transmission Planning also relies on complementary development efforts in the Resource Planning area to address broader planning challenges. In Resource Planning, the capacity expansion model and hourly production cost model provide planners the tools they need to explore a wide range of resource portfolios while performing optimization and detailed production cost studies to fully understand the behavior and costs of the system. To meet the rigors of the new planning challenges, the modeling tools and processes also need to allow planners to examine carbon compliance regimes, operational impacts of increasing levels of variable resources, utilization of different types of storage, applications of resources to address ancillary system needs and many other facets of future operations.

In 2020, the Company elected to move forward with deploying the EnCompass suite of resource planning models from Anchor Power Solutions to address these enhanced planning needs. The plans to shift to the new model were based, in part, on feedback from stakeholders as part of the IRP development process. The ISOP and Resource Planning teams are also working with the Fuels and System Optimization (FSO) Analytics team to study the effects of perfect foresight on production cost modeling results and explore the benefits of including their sub-hourly modeling and stochastic analysis to further refine modeling results for fast responding generation resources and storage to meet operational needs in the future with higher levels of variable renewable generation. The issue of "perfect foresight" in production cost modeling is addressed in more detail in Chapter 16.

Transitions to new models and functionality require time and substantial testing and integration efforts, which are currently underway with a goal of formally switching to EnCompass during the fourth quarter of 2020. As the Resource Planning team gains familiarity with these new tools, ISOP will also be assisting with development of new planning processes to support the collaboration between Resource Planning and the other planning disciplines and working toward integrating the new processes being developed in each of these areas. These integration efforts will involve development to support integration of modeling systems and also harmonizing inputs and coordinating planning cycles between the planning disciplines to allow for better flow of information and data required to produce the integrated planning results.

ISOP STAKEHOLDER ENGAGEMENT

Outreach has been and remains an important part of the ISOP effort. The Company's ISOP team has been gathering input from other utilities, national labs, EPRI, consultants, and academic groups to inform the Company's vision and work-scope to better address the challenges of modeling renewables and energy storage at both the distribution and transmission levels. There is also interest in these ISOP development efforts from the Company's regulators and customers, as well as environmental advocates, business interest groups, and other stakeholders. Duke initiated a series of stakeholder engagements in late 2019 to help address these interests, supported by ICF, an industry-leading consultant in advanced integrated planning and regulatory engagement.

The first stakeholder workshop in Raleigh on December 10, 2019 was well attended and provided a face-to-face opportunity for stakeholders to gain some insights from ICF on how integrated planning is unfolding across the industry, learn more about ISOP's development plans, and hear about some of the development work streams underway at that time. It also provided Duke participants with an opportunity to hear input and feedback from several of the Company's stakeholders and to engage in discussions on what is important to them and to the participants who attended. Several stakeholders constituting a diverse set of viewpoints participated in two panel sessions that helped ensure the workshop communication and information transfer was multidirectional. Considering the complexity of the subject matter and the initial nature of stakeholder engagement, it was a very successful kick-off event.

The ISOP/ICF team subsequently hosted two stakeholder webinar sessions on January 30, 2020 and March 20, 2020 to continue discussions on the Company's progress and introduce additional industry and ISOP topics for review and discussion with stakeholders. These exchanges provided productive opportunities for stakeholder feedback and discussions and helped support Duke's focus and priorities for future stakeholder sessions, as well as the information and services that will ultimately be shared as a result of ISOP efforts. All of the materials shared in these sessions and recordings of the sessions themselves are posted on the ISOP Information Portal[1] online for participants and other interested parties to review.

[1] https://www.duke-energy.com/our-company/isop.

As part of the broader ISOP stakeholder engagement effort, the Company has collaborated with North Carolina Electric Membership Corporation (NCEMC) to exchange ideas related to ISOP. As an extension of this collaboration, NCEMC has been working with the Company to improve coordination between the customer's Distribution Operator and the Company's Transmission Operator, and the two parties have developed a plan for coordinated testing of the wholesale customer's advanced DR and DER program for reliability coordination and local loading relief effects at the distribution and transmission levels. The parties have agreed to continue this collaboration beyond these initial steps as the ISOP process evolves to ensure that planning and operations are aligned. The Company will pursue additional ISOP-related interactions with other Distribution Operators within the balancing areas as future opportunities are identified through the normal course of outreach to these stakeholders.

ISOP hosted its second stakeholder workshop – a "Virtual Forum" due to pandemic safety concerns – on August 21, 2020 to update stakeholders on the continuing progress of the ISOP program and engage in more dialogue relating to what stakeholders consider important. A group of stakeholders presented on their desired outcomes from ISOP, which helped frame the different types of impact that ISOP could ultimately have, as well as further educate Duke participants on key issues that may be taken into consideration as the ISOP development process continues to unfold. All of the materials shared in the final session and recordings of the presentations will also be posted on the ISOP Information Portal online for participants and other interested parties to review. ICF will summarize the overall stakeholder engagement effort in a final, public-facing report in the fourth quarter of 2020.

The Company plans to provide future updates to stakeholders regarding the ISOP initiative through virtual webinars as the Company's development effort progresses toward the initial introduction of ISOP processes in the 2022 IRP. To help with managing expectations, it is worth reiterating that technology costs, supply chain, regulatory policy, and other challenges may require five to ten years for non-traditional solutions to become competitive options on a regular basis. Given the lead time to implement and refine complex new analytical processes as well as the importance of these efforts to support an affordable and reliable transition to net-zero carbon, it is critical to continue investing in this important work.

16 SUSTAINING THE TRAJECTORY TO REACH TO NET-ZERO

This chapter discusses, in qualitative terms, key elements needed to accelerate CO_2 reductions and sustain a trajectory to the Company's net-zero carbon goal, some which are at or beyond the fifteen-year horizon of the IRP. In 2019, the Company announced a corporate commitment to reduce CO_2 emissions from power generation by at least 50 percent from 2005 levels by 2030, and to achieve net-zero by 2050. This shared goal is important to many of the Company's customers and communities, many of whom have also adopted their own clean energy initiatives. The Company has already made significant progress by reducing CO_2 emissions by 39% across its entire seven-state territory since 2005, well ahead of the industry average of 33%.

The Company also released the Duke Energy 2020 Climate Report in April 2020, which offered insights into the complexities and opportunities ahead and provided an enterprise-level scenario analysis with an illustrative path to net-zero. Among the key elements identified for the path to net-zero carbon were:

- Investments in the grid to allow significant growth in renewables and energy storage, including a transition to intelligent grid controls to support growth of distributed resources and increased customer options,
- Advancement of planning tools and integration of planning processes to address the increasingly complex and dynamic grid and leverage the potential of energy storage and innovative customer programs and rate designs (see Chapter 15),
- Advancements in demand side management and energy efficiency (see Chapter 4 and Appendix D),

- Natural gas as a component of near-term opportunities for lower cost accelerated coal retirements,

- Advancement of Zero Emitting Load Following Resource (ZELFR) technologies, to be ready for commercial operation by the mid-2030s,

- Continued operation of the existing nuclear fleet,

- Consideration of pace and trajectory of CO_2 reduction relative to impacts on affordability and reliability for customers,

- Supportive policies to allow increased pace of interconnection and accelerated transmission and distribution infrastructure, and,

- Supportive policies for CO_2 reduction.

Support for a number of these elements has been evident in a variety of the Company's stakeholder engagement efforts. Key elements above that have been addressed in other Chapters of this IRP are referenced accordingly, while others are addressed below.

TRANSFORMATION OF THE ELECTRIC GRID

The nation's electric delivery system design is more than 100 years old, and much of the equipment installed across the country has been in place for decades. Since conventional generation resources have historically benefitted from economies of scale, the electric grid was designed to transport electricity from large centralized generation plants to customers. These centralized plants provided critical voltage support, and the downstream distribution system was designed for a one-way power flow from the transmission level down to the customer. This fundamental infrastructure is still the basis for the grid today, which has limitations in its capability to seamlessly integrate large amounts of renewable energy sources or fully leverage distributed resources, such as batteries at the local circuit level.

As the Company continues its shift away from traditional coal-fired generation sources in the Carolinas, the transmission and distribution grid infrastructure and associated control systems will need to transition to a more highly networked system capable of dynamically handling two-way power flows resulting from broader deployment of distributed energy resources and supporting new ways in which customers will consume energy. As a transformation to cleaner energy is occurring, customers' energy utilization is also expected to evolve in different ways through advancements in new customer options and movement toward electrification of transportation and other sectors of the economy.

These trends coupled with significant increased utilization of variable renewable energy sources and retirement of resources that have historically provided critical voltage support and full dispatchability over long durations help highlight the challenges ahead for utilities to identify and develop the grid infrastructure and interconnected resources that can efficiently and reliably serve customers' energy needs while also supporting CO_2 reductions.

Some of these emerging needs are already impacting the Company's planners and operators, but the transition needed to achieve carbon neutrality will introduce much more significant challenges. The Company has been proactive in identifying these trends and taking steps to develop the needed grid capabilities and in adapting our planning processes with the Integrated System and Operations Planning (ISOP) initiative. These initiatives recognize the traditional one-way power flow capacity planning approach must be adjusted to reflect the need for flexible and advanced control systems to handle a much more dynamic grid. Keeping the grid running reliably is a balancing act, where the amount of power put into the grid must equal the amount taken out in real time. The utility's control systems continuously ramp central station generating units up or down to meet electric demand of the customers it serves. With the growing contribution of renewable energy sources, which have variable output from minute to minute, this balance becomes increasingly challenging to maintain. In a similar way, as distributed generation becomes more prevalent on circuits, it becomes necessary to introduce localized intelligent control systems that can also contribute at the system level.

Today, the Company is working to build these capabilities through its grid investments that begin to lay a critical foundation for embracing large amounts of private renewable energy. These investments include:

1) Self-optimizing grid (SOG) which fundamentally redesigns key portions of the distribution system and transforms it into a dynamic, smart-thinking, self-healing grid that can accommodate two-way power flows generated by the increased utilization of distributed resources.

2) Integrated Volt-Var Control (IVVC) will allow the Company to more closely monitor and control the voltage on the distribution system and more effectively manage voltage fluctuations due to intermittency of renewable energy sources, while enabling energy and peak demand savings to our customers over time.

3) Distribution automation, which leverages modern and often remotely operated equipment that supports continuous system health monitoring.

4) Transmission system intelligence, which improves system device communication capabilities enabling better protection, monitoring and optimization of system health and equipment.

5) Advanced Metering Infrastructure (AMI) that enables net metering while also providing the data necessary to better understand customer usage and develop enhanced customer programs.

6) Advanced Distribution Planning (ADP) tools and analytic processes that will help enable the integrated system operations planning process needed to optimize future investment decisions in the distribution system as next-generation technologies emerge and advance to become cost-competitive relative to traditional distribution investments.

7) Battery storage at the substation level can help with reliability and potentially balance and optimize load during peaks as well as low renewable periods to maximize carbon free generation on a circuit level.

These represent foundational, no-regrets investments that equip the grid with capabilities and tools to successfully transition from legacy one-way circuits to modern two-way power flow circuits. This foundation enables the legacy electric grid to better support carbon reductions by allowing increased integration of distributed resources and advancement of programs to leverage flexible demand, while also enhancing circuit resilience to withstand and recover from extreme weather events.

Leveraging the ISOP process and the Advanced Distribution Planning (ADP) tool for analysis and prioritization will be key for making sound economic choices at the circuit level complementing transmission and generation capacity needs. There are opportunities to advance a greener circuit design process to combine and coordinate with customer-facing programs to enhance peak demand control of customer loads, enable DERs, and support electric vehicle growth. Managing cost drivers for maintaining the grid while meeting carbon reduction goals is a key value opportunity.

Embracing demand response through advanced customer options with load-shaping programs is an essential element in the overall effort to reach the shared interest goal of net-zero CO_2 emissions, making it easier for customers to manage their energy usage and carbon footprint while supporting a greener grid and power supply. To accomplish this, the local grid must become more responsive, requiring intelligent, robust controls and customer programs that help to optimize DER integration. This vision would include supporting customer programs for managing and coordinating home and fleet EV battery charging. Managed EV charging is an emerging and valuable tool to support lower carbon emissions by reducing existing load peaks and eliminating risks from new ones, such as the transportation sector.

Over time, applying a holistic, customer-focused design approach combining advanced circuit monitoring and control capabilities with innovative customer programs and rate designs will further reduce customer outage impacts while also enabling a more sustainable, efficient and greener grid. As new opportunities are identified, the ISOP process will ensure balanced choices that manage cost, while growing the DER portfolio and enabling customers with clean, renewable energy options.

BUILDING ON SUCCESS AND SUSTAINING THE TRAJECTORY TO REACH NET-ZERO

The Company has made strong progress reducing CO_2 emissions since 2005, achieving a 38% reduction across the combined DEC/DEP systems between 2005 and 2019 – well ahead of the industry average of 33%. This progress is notable considering that Duke Energy's carbon intensity in the Carolinas was already low in 2005 relative to the industry average due to the significant contribution of emissions-free nuclear energy. Over this timeframe, the Company has retired nearly 4 GW of coal resources in the Carolinas. These retirements were primarily enabled by replacement with modern efficient natural gas combined cycle generation, which reduces emissions by more than 50% for each MWh replaced while maintaining affordability and reliability for customers. The replacement of coal with gas resources has been the single largest factor contributing to the Company's success in reducing the combined DEC/DEP CO_2 emissions. The Company has also interconnected nearly 4GW of renewable generation over the past decade, supporting the Carolinas emergence as a national leader in solar capacity. Comparing the level of generation from these renewables in 2019 to average carbon emissions of dispatchable resources that would have otherwise been used to balance customer demand, the renewable resources contributed approximately 11% of the 38% carbon reduction.

While the contribution to carbon reduction from renewables is smaller than that of natural gas, both resources play important roles in the overall reduction of 38%. There is a learning opportunity in this experience. In adding roughly equivalent amounts of natural gas combined cycle and solar generation, the ability of natural gas combined cycle generation to displace the coal generation at much higher capacity factors drove the significantly larger portion of the 38% carbon reduction while keeping customer costs low. Finding the right balance between accelerating the pace of emissions reductions and new technology deployment while maintaining affordability for customers will continue to be an important consideration moving forward.

Although natural gas has and could continue to play a key role in accelerating coal retirements cost effectively[1], that role is expected to gradually change over the life of the natural gas assets, as noted in the Company's 2020 Climate Report. During the IRP Stakeholder process, some stakeholders voiced concerns about the risks of new gas generation assets becoming stranded. This was addressed by running a stress test case with an assumption of a shortened twenty-five-year life for natural gas units. With this assumption, the capacity expansion model continued to select natural gas units for the Base cases. There is also the possibility that generation, transport, and utilization of green hydrogen could become economic and extend the life of gas assets while reducing or eliminating carbon emissions. Blends of up to 10% hydrogen should be possible with the existing gas fleet with minimal tuning required, and new gas turbines are being designed for much higher capabilities of up to 100% hydrogen without modifications. The Company is partnering with Siemens and Clemson University on a proposal for a DOE study on the use of hydrogen for energy storage as a first step in exploring these opportunities.

PACE OF ADOPTION AND BENEFITS OF RESOURCE DIVERSITY

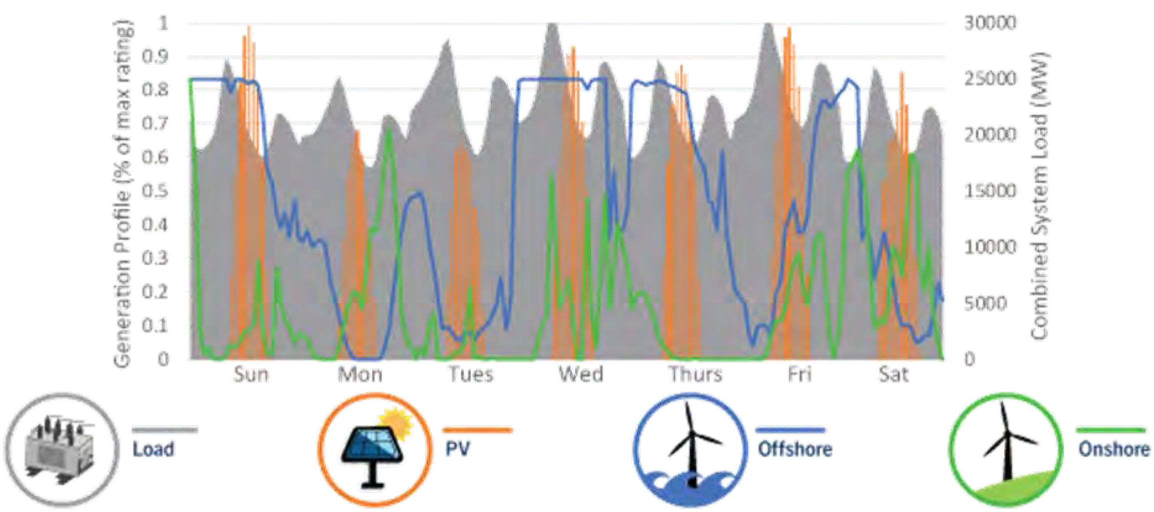
Moving forward, it will be important to consider both the pace of adoption and the benefits of portfolio diversity to mitigate risks of being too dependent on a small group of technologies. The graph below illustrates the benefits of adding offshore wind and, to a lesser extent onshore wind to improve the contribution of renewables to winter peak demand, which drives the resource planning process. For these emerging technologies, a measured pace of adoption can simultaneously promote technology

[1] Getting to Zero Carbon Emissions in the Electric Power Sector, Joule, Dec. 19, 2018.

development and operational experience with new technologies, while also allowing customers to benefit from price declines over time. Also, as shown by the NREL Phase 1 Carbon Free Resource study, as more of a given type of renewable resource is added to the system, the energy benefit diminishes, which reinforces the benefits of favoring diversity among renewable resources as the level of installed renewables increases. The Company continues to work with NREL and stakeholders to better understand the potential impacts of high renewable portfolios as well as the benefits of improving the diversity of renewables by evaluating onshore and offshore wind. For this reason, the Company has included both onshore and offshore wind in this IRP, even though there are substantial technical and policy issues that would need to be addressed to make such a pathway plausible.

The Company continues to investigate these opportunities through participation with the NC Clean Energy Plan modeling working group and the NREL Phase 2 Carbon Free Resource study. Additionally, the Company has partnered with NREL and a number of other National Laboratories to submit a DOE proposal for an extensive study of Reliability and Resilience in Near-Future Power Systems.

FIGURE 16-A
CAROLINAS RENEWABLE ENERGY PROFILES



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NEED FOR ENHANCEMENTS IN MODELING ASSUMPTIONS AND TECHNIQUES

One of the key uncertainties of these 2020 Carolinas modeling efforts is the feasibility of onshore wind. Aside from the policy barriers, there is a significant need for meteorological towers to collect wind speed history in key areas across the Carolinas to gain confidence in predicted capacity factors. The Carolinas onshore wind profiles used in this IRP were provided by a third party and are likely not based on wind speeds measured near the expected hub heights. The Company is working to improve the quality of Carolinas onshore wind profiles for use in future IRPs.

Beyond the current work with NREL and the NC Clean Energy Plan, there are a number of issues that require detailed modeling and analysis to better understand the operational risks associated with significantly increased reliance on energy storage for meeting capacity needs coupled with reliance on very high levels of renewable resources for energy. First, traditional production cost modeling, used in key processes ranging from IRP development to the unit commitment planning that drives actual daily operations, has "perfect foresight" of system load, renewable output, unplanned outages and derates, etc. While this is an unrealistic assumption, with the moderate levels of renewables and relatively low levels of energy storage today, the impact of the perfect foresight is small due to the abundance of dispatchable resources that do not require the precise timing that short duration energy storage does (for both charging and discharging) to ensure that the highest load hours are fully covered.

With some portfolios in this IRP containing approximately four times the present level of renewables and storage and a much smaller proportion of long duration dispatchable resources, new production cost modeling techniques and operational protocols will need to be developed to properly represent and actively manage the risks related to forecast error and imperfect foresight. Second, while there is considerable experience with managing the impacts of extreme weather events on the existing fleet with its current abundance of flexible, long duration dispatchable resources, there is no experience in the US or abroad with the scale of dependence on short duration energy storage represented by the 70% reduction and no new gas portfolios of this IRP. These issues require new modeling techniques to assess and manage the challenges to ensure operational implications of the transition are well understood.

Notably, the Company is participating with Duke University and other academic researchers and industry reviewers in a DOE project as part of the ARPA-E PERFORM program (Performance-based

Energy Resource Feedback, Optimization, and Risk Management). This is a three-year study effort just getting underway which will focus on transforming the electric grid management through improved understanding of asset risk, system risk, and optimal utilization of all grid assets. This specific project will address two main problems in grid management: 1) day-ahead operational reserves are often set based on heuristic rules that are disconnected from the real conditions of the assets and the system, and, 2) generation resources are scheduled without considering their impact on exacerbation or reduction of system risk. The Company has shared their dynamic reserve management methodology with the research team and looks forward to exploring improvement opportunities in these areas as the study progresses.

ADVANCING ZERO EMISSIONS LOAD FOLLOWING RESOURCE (ZELFR) TECHNOLOGY

> *"The key technologies the energy sector needs to reach net-zero emissions are known today, but not all of them are ready."* [2]

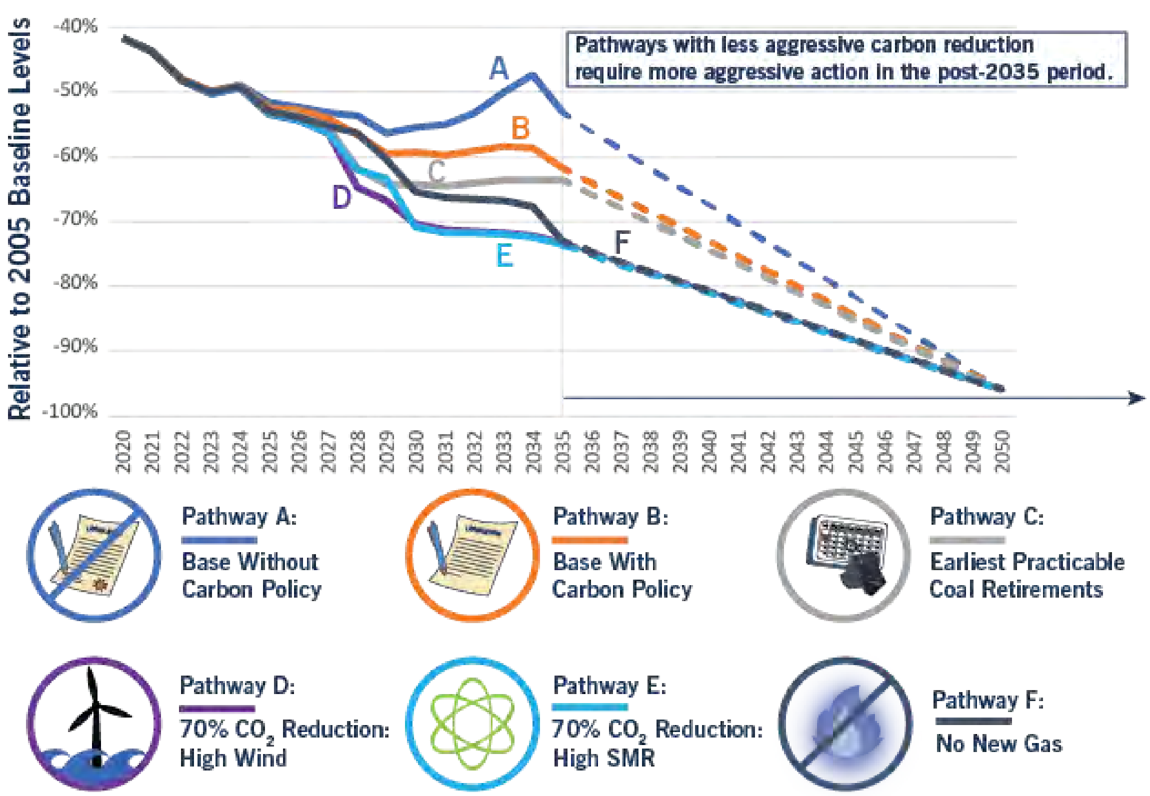
As noted in the Climate Report and in independent studies and reports, to reach deep carbon reductions, very low- or zero-emitting technologies that can be dispatched to meet energy demand over long durations will be needed to replace carbon emitting resources.[3] Innovation is a critical part of our path to achieving net-zero by 2050. With existing technologies, the Company can make important progress but cannot close the gap. To achieve net-zero, ZELFR technologies are needed that can respond to dynamic changes in both customer demand and renewable generation. The next decade is critical because these technologies need to be developed, demonstrated, refined and scaled on a very aggressive timeline to enable timely, cost-effective fossil retirements. While solar, wind and currently available energy storage have important roles to play now and in the future, as noted above their contribution begins to diminish as higher levels of renewable and storage penetration are reached, and resources capable of following load over long durations become increasingly needed to meet system capacity and energy needs reliably as fossil based resources are retired over time. ZELFRs will also ultimately be needed to replace the base load capability of existing nuclear units as they begin to retire in the 2050s and beyond. ZELFR technologies may include advanced nuclear; carbon capture, utilization and storage (CCUS); hydrogen and other gases; and long duration storage technologies such as molten salt, compressed/liquefied air, sub-surface pumped hydro, power to gas (e.g., hydrogen, discussed above) and advanced battery chemistries.

[2] IEA, Special Report on Clean Energy Innovation, Accelerating technology progress for a sustainable future.
[3] The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation, Nov. 18, 2018.

The 70% reduction cases in this IRP rely on the accelerated adoption of offshore wind and small modular reactors (SMRs) – a ZELFR technology – along with a significant investment in storage. Of the three portfolios reflecting the most aggressive carbon reductions, portfolio E (70% Reduction with High SMRs) yielded the lowest customer cost impact. To be clear, the Company does not expect to build SMRs by 2030 but included SMRs to illustrate the importance of support for advancing these technologies as part of a balanced plan to achieve net-zero carbon. These more aggressive portfolio transitions are more costly but, as illustrated below, could position the portfolio well for future climate policy by accelerating deployment of advanced technologies, requiring less aggressive action after 2035 to reach net-zero.

FIGURE 16-B

CARBON REDUCTION TRAJECTORIES ON PATH TO NET-ZERO



The Company is actively engaged in industry efforts to support the development of ZELFRs. For example:

Advanced Nuclear: The Company has representatives on nuclear industry groups and advisory boards working on small modular reactor and advanced reactor technologies. The Company is also working with private and public sectors to drive research, development and demonstration of additional advanced reactor technologies under the DOE's Advanced Reactor Demonstration Program that supports innovative and diverse designs with the potential for commercialization in the mid-2030s.

Hydrogen/Other Gases: In addition to the research proposal with Siemens and Clemson University described earlier, the Company is a founding member of EPRI and GTI's Low Carbon Research Initiative. The overall goal of this initiative is to focus on fundamental advances in a variety of low-carbon electric generation technologies and low-carbon chemical energy carriers -- such as clean hydrogen, bioenergy, and renewable natural gas – which are needed to enable affordable pathways to economy-wide decarbonization.

Long Duration Energy Storage: As described earlier, Duke Energy has been involved with numerous battery energy storage pilots during the past 10 years. This has included active evaluation of long duration chemistries since 2016. The underlying chemistries of several pilots have the potential to provide daily or even seasonal energy storage, contributing to long duration storage applications in the future. Duke Energy will also increase the capacity at its Bad Creek facility in South Carolina by about 320 MW as it upgrades the facility. While this is not a pilot project, it represents an important contribution to our long duration storage capacity in the Carolinas.

Carbon Capture: Duke Energy has a similarly long history of engagement in CCUS research, including pilot scale projects and partnerships with the Electric Power Research Institute, the Department of Energy, national labs and others. One recent example is a partnership to perform an initial engineering design for a commercial-scale, membrane-based CO_2 capture system at Duke Energy's 600-MW East Bend power plant in Kentucky. Notably, deployment of carbon capture in the Carolinas would likely be dependent on interstate transportation infrastructure or innovative utilization opportunities due to a lack of suitable geology for CO_2 storage.

The Company will continue to monitor, evaluate and support the most promising emerging technologies to advance understanding and be prepared to act if more aggressive state or federal regulations CO_2 requirements are enacted.

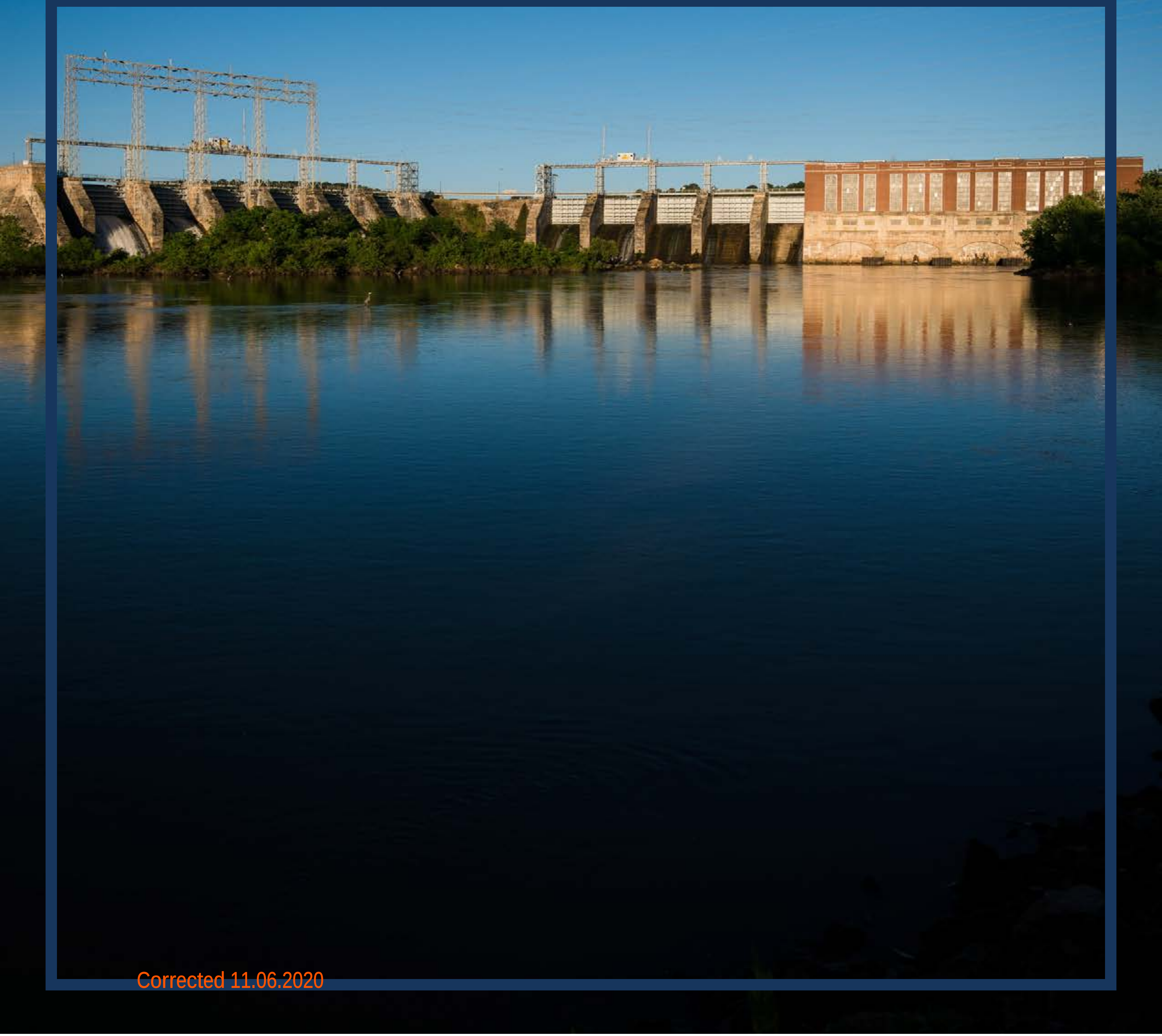
THE NEED FOR SUPPORTIVE POLICIES

As shown by the Base without Carbon Policy pathway (A), from a modeling standpoint, carbon reductions could stall and reverse before reaching a 60% reduction in absence of policy to drive more aggressive additions of carbon-free resources. Carbon policy alone, however, is insufficient to address all the challenges associated with the dramatic transition of the grid and generation fleet to reach net-zero carbon, particularly for winter peaking, energy intensive Southeastern utilities. Federal policies are also critical to support and accelerate research, development, demonstration, and deployment of advanced technologies needed to meet this important goal. As noted in the Climate Report, for Duke Energy to achieve net-zero carbon emissions, the pace of interconnections over the next three decades is expected to be more than double that of the highest decade of generation growth in U.S. history, so the regulatory approvals of interconnection queue reform that the Company has been working on diligently with stakeholders over the last year is a critical hurdle. This pace of resource additions will also pose challenges for the interconnection-related transmission and distribution upgrades, transmission right-of-way acquisition, permitting, regulatory approval processes, supply chain, and generation siting as ideal sites are exhausted and suitable sites become increasingly scarce. These challenges are exacerbated if surrounding utilities are competing for the same resources to complete similar resource plans. It will be important to consider these factors and develop strategies to help create a supportive ecosystem for the deployment of carbon-free technologies and associated infrastructure as policymakers contemplate opportunities to accelerate the transition to net-zero while maintaining reliability and affordability for customers.

As described more fully in the 2020 Duke Energy Climate Report[4], policies will be increasingly important to support the changes required to transform the grid and drive advancement of carbon free resource technologies needed to reach the shared goal of net-zero carbon.

[4] https://www.duke-energy.com/_/media/pdfs/our-company/climate-report-2020.pdf?la=en.

APPENDICES



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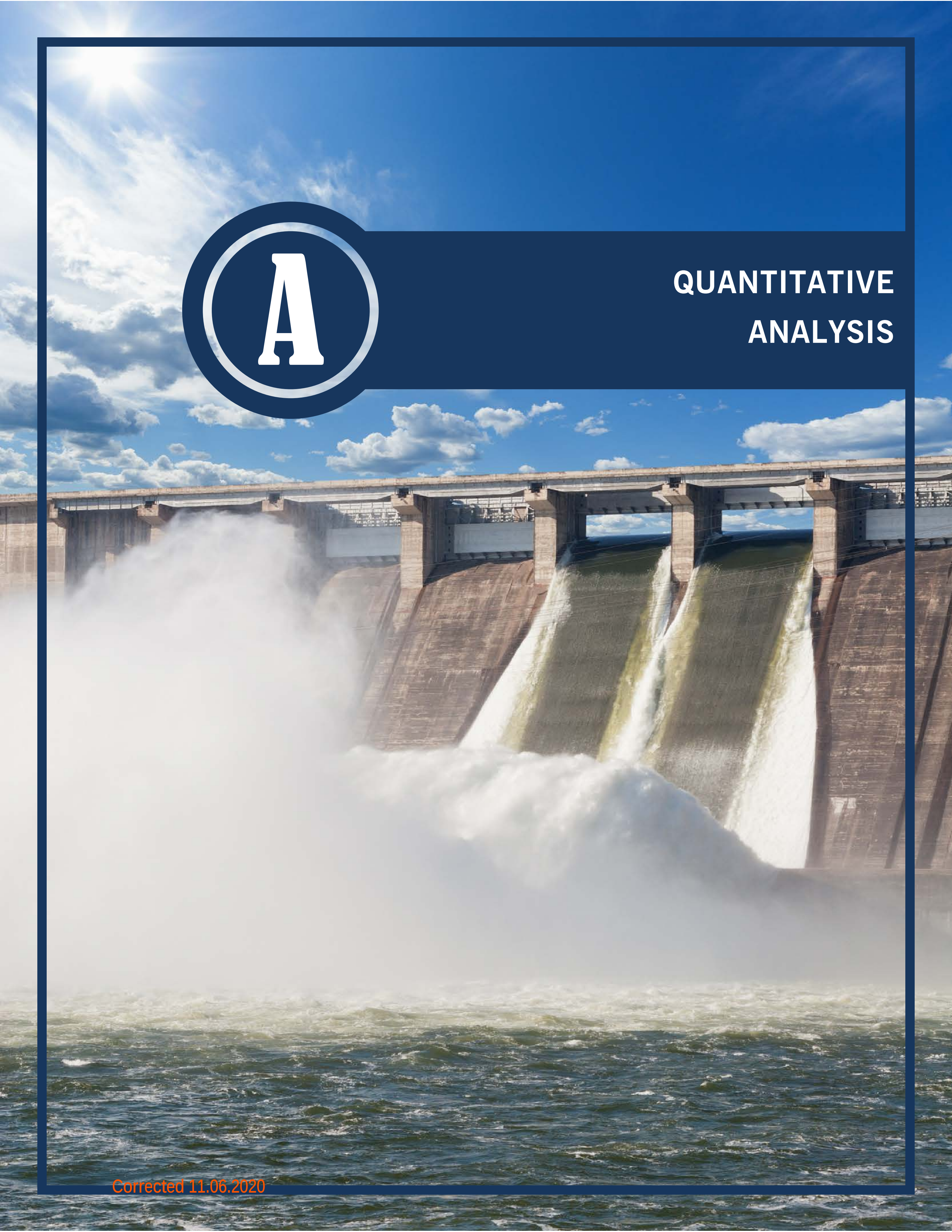

QUANTITATIVE ANALYSIS

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APPENDIX A: QUANTITATIVE ANALYSIS

This appendix provides an overview of the Company's quantitative analysis of the resource options available to meet customers' future energy needs. An evaluation of the economic retirement dates of DEC's coal plants helped establish the starting point for the quantitative analysis discussed in this appendix. Sensitivities on major inputs informed the development of multiple portfolios that were then evaluated under nine scenarios that varied combinations of fuel prices and CO_2 constraints. These portfolios were analyzed, identifying trade-offs between cost and carbon reductions, while considering opportunities and barriers to enable the portfolio's transition. Each of these plans account for the cost to customers, resource diversity, reliability and the long-term carbon intensity of the system and any of the six portfolios presented are potential pathways depending on future federal and state policies and technology advancements and cost trajectories.

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

OVERVIEW OF ANALYTICAL PROCESS

The analytical process consists of six steps:

1. Evaluate economic retirement dates of coal plants
2. Assess resource needs
3. Identify and screen resource options for further consideration
4. Develop base planning portfolio configurations and perform sensitivity analysis
5. Develop alternative portfolio configurations
6. Perform portfolio analysis over various scenarios

1. EVALUATE ECONOMIC SELECTION OF COAL PLANT RETIREMENT DATES

As discussed in Chapter 11, DEC conducted a detailed coal plant retirement analysis to determine the most economic retirement dates for each of the Company's coal assets. This analysis identified the retirement dates used in the Base Planning with Carbon Policy and Base Planning without Carbon Policy for each of DEC's coal plants. In addition to the economic retirement analysis, the Company also determined the earliest practicable retirement dates for each coal asset. The "earliest practicable" retirement date portfolio is discussed later in this appendix.

Through the process detailed in Chapter 11, the following economic coal retirement dates were used in developing the base planning portfolios.

TABLE A-1
ECONOMIC RETIREMENT DATES OF DEC COAL PLANTS

	2019 IRP RETIREMENT YEAR (JAN 1)	2020 IRP MOST ECONOMIC RETIREMENT ANALYSIS RETIREMENT YEAR (JAN 1)
Allen 1	2025	2024
Allen 2	2025	2022
Allen 3	2025	2022
Allen 4	2028	2022
Allen 5	2028	2024
Cliffside 5	2033	2026
Marshall 1 – 4	2035	2035
Belews Creek 1 & 2	2039	2039
Cliffside 6	2049	2049

ALLEN STATION RETIREMENT DISCUSSION

The economic retirement analysis determined that the retirement of Allen station was economic by 2022; however, at least two of the five units must remain in service until completion of a new switch yard project by 2024.

Allen unit retirements in 2022 (YE2021) and 2024 (YE2023) and the associated new South Point switchyard, which is necessary to allow for the retirement of all five Allen units, will bring economic value to customers and further the clean energy goals held by the Company and stakeholders. As with all unit retirement dates in the IRP, this is not a commitment to retire the Allen units on this timeline but rather contains the Company's most recent estimate of retirement economics at the time of this filing. Official retirement will require final management approval with final retirement dates contingent upon the finalization of the supporting switchyard project and other operational considerations.

2. ASSESS RESOURCE NEEDS

The required load and generation resource balance needed to meet future customer demand was assessed as outlined below:

- **Customer peak demand and energy load forecast –** identified future customer aggregate demands to determine system peak demands and developed the corresponding energy load shape.

- **Existing supply-side resources –** summarized each existing generation resource's operating characteristics including unit capability, potential operational constraints and projected asset retirement dates.
- **Operating parameters** – determined operational requirements including target planning and operational reserve margins and other regulatory considerations.

Customer load growth, the expiration of purchased power contracts and additional asset retirements result in resource needs to meet energy and peak demands in the future. The following assumptions impacted the 2020 resource plan:

- **Peak Demand and Energy Growth -** The growth in winter customer peak demand after the impact of energy efficiency averaged 0.6% from 2021 through 2035. The forecasted compound annual growth rate for energy is 0.5% after the impacts of energy efficiency programs are included.

- **Planned Generation Uprates and Additions -**
    - Runner upgrades totaling 260 MW between 2020 and 2024 at Bad Creek Pumped-Storage Generating Station
    - Completion of the 402 MW Lincoln CT Unit #17 in 2024
    - Nuclear uprates at Oconee and Catawba totaling 57 MW

- **Reserve Margin** - A 17% minimum winter planning reserve margin for the planning horizon

3. IDENTIFY AND SCREEN RESOURCE OPTIONS FOR FURTHER CONSIDERATION

The IRP process evaluated EE, DSM and traditional and non-traditional supply-side options to meet customer energy and capacity needs. The Company developed EE and DSM projections based on existing EE/DSM program experience, the 2020 market potential study, input from its EE/DSM collaborative and cost-effectiveness screening for use in the IRP. Supply-side options reflect a diverse mix of technologies and fuel sources (gas, nuclear, renewable, and energy storage). Supply-side options are initially screened based on the following attributes:

- Technical feasibility and commercial availability in the marketplace
- Compliance with all Federal and State requirements
- Long-run reliability
- Reasonableness of cost parameters

The Company compared the capacity size options and operational capabilities of each technology, with the most cost-effective options of each being selected for inclusion in the portfolio analysis phase. An overview of resources screened on technical basis and a levelized economic basis is discussed in Appendix G.

RESOURCE OPTIONS

ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT

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

The base planning assumptions for EE and DSM portfolios incorporates projected program adoption rates, and costs based on a combination of both internal company expectations, inclusive of current programs, and projections based on information from the 2020 market potential study. The program costs used for this analysis leveraged the Company's internal projections for the first five years and in the longer term, utilized the updated market potential study data incorporating the impacts of customer participation rates over the range of potential programs. Additionally, the Company included the impacts on energy and winter peak demand from the newly proposed IVVC program discussed in Appendix D.

Over the 15-year planning horizon, EE and DSM programs, including the new IVVC program discussed in Appendix D, are expected to provide over 1,200 MW of winter peak demand reduction in the base planning scenarios.

SUPPLY-SIDE

The following technologies were included in the quantitative analysis as potential supply-side resource options to meet future capacity needs:

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DISPATCHABLE (WINTER RATINGS)			
BASELOAD	PEAKING / INTERMEDIATE	STORAGE	RENEWABLE NON- DISPATCHABLE (WINTER RATINGS)
1,224 MW, 2x2x1 Advanced Combined Cycle (Duct Fired, No Inlet Chiller)	913 MW, 4 x 7FA.05 Combustion Turbines (CTs)	50 MW / 200 MWh Lithium-ion Battery	150 MW Onshore Wind
684 MW, 12 Small Modular Reactor Nuclear Units (NuScale)		50 MW / 300 MWh Lithium-ion Battery	600 MW Offshore Wind
21 MW – Combined Heat & Power (Combustion Turbine)		1,400 MW Pumped Storage Hydro (PSH)	75 MW Fixed-Tilt (FT) Solar PV
			75 MW Single Axis Tracking (SAT) Solar PV
			75 MW SAT Solar PV plus 20 MW / 80 MWh Lithium-ion Battery

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4. DEVELOP BASE PLANNING PORTFOLIO CONFIGURATIONS AND PERFORM SENSITIVITY ANALYSIS

The step is broken down into three sections. The first section discusses the key variables in portfolio development and those considered in sensitivity and portfolio analysis. The second discusses the Base Planning portfolio development and results. The final section details the overall quantitative analysis of the individual sensitivity screening cases that were analyzed in the sensitivity analysis to inform the development of the alternative portfolios.

VARIABLES CONSIDERED IN SENSITIVITY & PORTFOLIO ANALYSIS

The Company uses base planning assumptions for the development of the base cases. However, the Company also conducted sensitivity analysis of various drivers using the expansion planning simulation modeling software, *System Optimizer* (SO). The expansion plans from these sensitivities produced by SO were then processed through the more detailed hourly production cost model, PROSYM to provide production costs for each of the expansion plans. The results of the sensitivity analysis were used to inform the development of the alternative portfolios presented in the IRP. Each of the base planning and alternative portfolios were analyzed under combinations of fuel and carbon tax trajectories in PROSYM in order to compare the Present Value of Revenue Requirements (PVRR) of each portfolio under the various scenarios, as well as, develop an estimate of average residential monthly bill impact of implementing the various portfolios under base planning assumptions. An overview of the key variable assumptions for the development of the base cases and for the Sensitivity and Scenario Analyses considered in both SO and PROSYM are outlined below:

LOAD FORECAST

DEC modeled the impacts of changes to the load forecast on the expansion plans. The Company based these sensitivities on the near-term growth and recession scenarios provided by Moody's Analytics. The impacts to the load forecast are summarized below:

TABLE A-2

LOAD FORECAST SENSITIVITY PARAMETERS

	LOW	BASE	HIGH
2035 Winter Peak Demand, MW	19,235	19,473	19,580
2035 Annual Energy, MWh	96,670,332	97,834,515	98,337,545

IMPACT OF POTENTIAL CARBON CONSTRAINTS

The base CO_2 price was developed to incentivize less carbon intensive resources on the path to net-zero carbon by 2050. Based on the earliest expected time to propose, pass and implement legislation or regulation the CO_2 price is set to begin in 2025. Ultimately, the CO_2 price will likely be dependent on many factors such as fuel and technology cost, tax incentives as well as pace of reduction goals.

In the 2019 IRP, the CO_2 price also started in 2025 at $5/ton and escalated at a rate of $3/ton per year, which incentivized CO_2 reductions of 60 to 70% by 2050 from a 2005 baseline. However, the price was not high enough to incentivize zero-emitting load-following resources (ZELFR) such as nuclear, hydrogen fueled generation or carbon capture and sequestration in lieu of natural gas generation prior to 2050.

In September 2019, after the filing of the 2019 IRP, Duke Energy announced an enterprise wide CO_2 reduction goal of at least 50% by 2030 and to be net-zero carbon by 2050. In addition to accelerating coal retirements, additional renewables and storage, there is a need for ZELFR technologies in 2035 to 2050 timeframe to facilitate the replacement of remaining coal generation and existing natural gas combined cycle generation as they meet their projected retirement dates. The company's analysis showed a CO_2 price starting at $5/ton in 2025 increasing at a rate of $5/ton per year incentivized ZELFR technology in the 2040 to 2050 timeframe, where increasing at a rate of $7/ton accelerated the selection of ZELFRs in the 2035 to 2040 timeframe. Both the $5 and $7/ton year price incentivize battery storage to meet a portion of new peaking need by 2030, additional renewables, accelerated coal retirements and limiting dispatch of carbon emitting generation.

There have been multiple federal legislative proposals that Duke has been tracking including:

- **Climate Leadership Council** – $40/ton escalating at 5% per year

- **CLEAN Futures Act –** A Clean Electricity Standard (CES) that incentivized similar reductions to $5/ton escalating at $7/ton per year

- **Energy Innovation and Carbon Dividend Act (H.R. 763) –** $15/ton escalating at $10 /ton per year

- **American Opportunity Carbon Free Act of 2019 (S. 1128) –** $52/ton escalating at 8.5% per year

The Climate Leadership Council and CLEAN Futures Act each drive a similar pace of carbon reduction as the $5/ton and $7/ton per year carbon price trajectories. The higher CO_2 prices associated with H.R. 763 and S. 1128 would drive retirement of coal and gas generation at a faster pace which would accelerate the need for ZELFRs prior to 2035. However, the pace of CO_2 reduction would be limited by the amount of renewables and storage that could be interconnected in a given year, technological development and deployment of storage and ZELFRs technologies and the impact on customer rates.

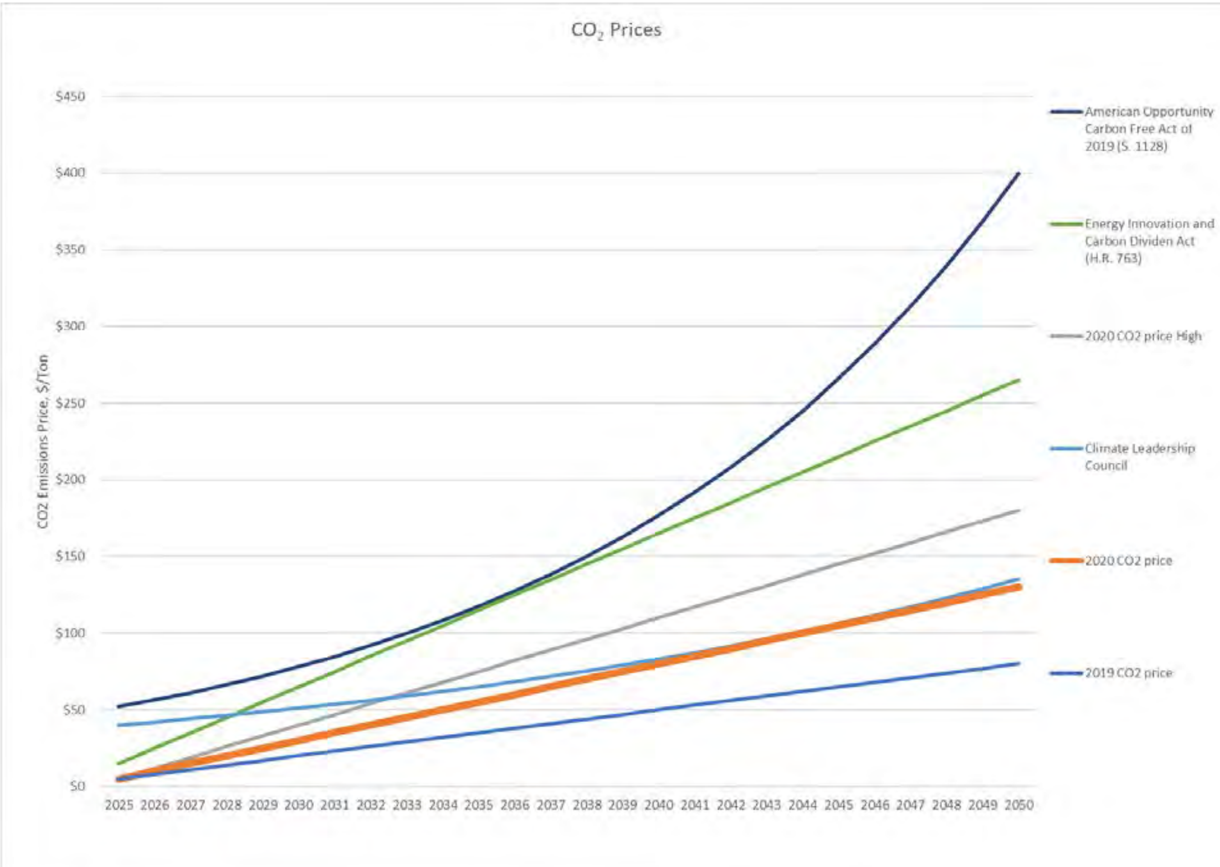
In consideration of the mentioned legislative proposals and consistent with Duke Energy's CO_2 reduction goal, the Reference 2020 CO_2 price is $5/ton starting in 2025 escalating at a rate of $5/ton per year. This CO_2 price trajectory incentivizes the continued adoption of renewables, storage, accelerated coal retirements which supports a path to net-zero by 2050. When comparing alternative plans the inclusion of the CO_2 price in the overall project economics would be reflective of a carbon tax, and if excluded, would be reflective of a CO_2 mass cap or cap and trade with allowance allocations.

- **Base CO_2 Price –** $5/ton in 2025 and escalating at $5/ton annually applied to all stack carbon emissions.

- **High CO_2 Price –** $5/ton in 2025 and escalating at $7/ton annually applied to all stack carbon emissions.

FIGURE A-1

COMPARISON OF CO_2 PRICES AND OTHER CO_2 REFERENCE PRICES



COAL PLANT RETIREMENT DATES

As described in Chapter 11, DEC evaluated the economic coal retirement dates for each coal plant. These dates were used in the base planning cases presented in the IRP. Additionally, DEC determined the earliest practicable retirement dates for each plant which contemplated the earliest date, setting aside normal economic considerations, that each coal plant could be retired but still giving consideration to the time it would take to place replacement resources into service. While the earliest practicable dates are technically feasible it would likely take supporting policy to effectuate such an aggressive retirement schedule, The complexities in the siting, permitting, construction and regulatory approvals for such a large amount of replacement resources in a short period of time would, in all likelihood, not be feasible without new supporting policy. This is emphasized when taking into account the fact that the combined DEC/DEP systems would simultaneously be retiring all coal units prior to 2030 or in the case of Cliffside unit 6 cease burning coal by 2030 limiting future operations to entirely natural gas in this scenario. The earliest practicable coal retirement dates and additional considerations are discussed later in this appendix.

ENERGY EFFICIENCY

DEC modeled the adoption rate and program cost associated with EE based on a combination of both internal company expectations and projections based on information from the 2020 market potential study. Table A-3 provides the base, enhanced, and low EE MW and MWh impacts by 2035 including measures added in 2020 and beyond.

TABLE A-3

EE SENSITIVITY ANALYSIS PARAMETERS

	LOW	BASE	HIGH
Winter Peak MW Reduced by 2035	283	377	424
MWh Reduced by 2035	2,089,358	2,785,811	3,125,222

DEMAND SIDE MANAGEMENT & IVVC

As discussed previously, DEC modeled the adoption rate and program cost associated with DSM based on a combination of both internal company expectations and projections based on information from the 2020 market potential study. Additionally, the Company included the newly developed IVVC program which provides a reduction to winter peak demand and overall energy consumption. Table A-4 provides the base, enhanced, and low DSM MW impacts by 2035 including measures added in 2020 and beyond. The base case was derived directly from the market potential study, while the enhanced case incorporated the market potential study and impacts associated with potential rate design demand response programs. The low case is simply a 25% reduction in adoption and cost impacts of DSM programs. The base IVVC program impacts are included in all three sensitivities.

TABLE A-4
DSM SENSITIVITY ANALYSIS PARAMETERS

	LOW	BASE	HIGH
Winter Peak MW Reduced by 2035	688	845	1,428

SOLAR, SOLAR + STORAGE, AND WIND GENERATION

Three levels of renewable generation were evaluated as discussed in Appendix E. Each level included varying assumptions regarding penetration of solar and solar plus storage, wind availability, and annual interconnection limits. As discussed further in Appendix E, the base case includes renewable capacity components of the Transition MW, such as capacity required for compliance with NC REPS, PURPA purchases, the SC DER Program, NC Green Source Rider (pre HB 589 program), and the additional three components of NC HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). The Base Case also includes additional projected solar growth beyond NC HB 589, including expected growth from SC Act 62 and the materialization of additional projects in the transmission and distribution queues. The Base Case does not attempt to project future regulatory requirements for additional solar generation, such as new competitive procurement offerings after the current CPRE program expires.

In addition to the base case, a high and low case were developed. These portfolios do not envision a specific market condition, but rather the potential combined effect of a number of factors. For example, the high sensitivity could occur given events such as high carbon prices, lower solar capital costs, economical solar plus storage, continuation of renewable subsidies, and/or stronger renewable energy mandates. Additionally, the high case also considers a combination of onshore and offshore wind as viable resources beginning in the 2030 timeframe. On the other hand, the low sensitivity may occur given events such as lower fuel prices for more traditional generation technologies, higher solar installation and interconnection costs, and/or high ancillary costs which may drive down the economic viability of future incremental solar additions. These events may cause solar projections to fall short of the Base Case if the CPRE, renewable energy procurement for large customers, and/or the community solar programs of HB 589 do not materialize or are delayed

In all three cases, incremental solar, solar plus storage, and onshore Carolinas wind were available for selection in the capacity expansion model. However, the annual amount of solar and solar plus storage that could be selected in each case was limited. Table A-5 details the differences between the inputs of the three renewable cases.

TABLE A-5
RENEWABLES SENSITIVITY ANALYSIS PARAMETERS

	LOW	BASE	HIGH
Forced Solar by 2035, Nameplate MW	2,463	3,475	5,802
Forced Central US Wind by 2035, MW	0	0	638
Forced Offshore Carolinas Wind by 2035, MW	0	0	138
Allowed Solar & Solar plus Storage Annually, MW/Year	225	300	500
Allowed Onshore Carolinas Wind Annually, MW/Year	150	150	150

Additionally, as described in Chapter 7, transmission upgrade costs associated with interconnecting these distributed resources was estimated. These costs were applied after the technology was selected and are included in the PVRR and average residential bill impacts discussed later in this appendix.

FUEL PRICES

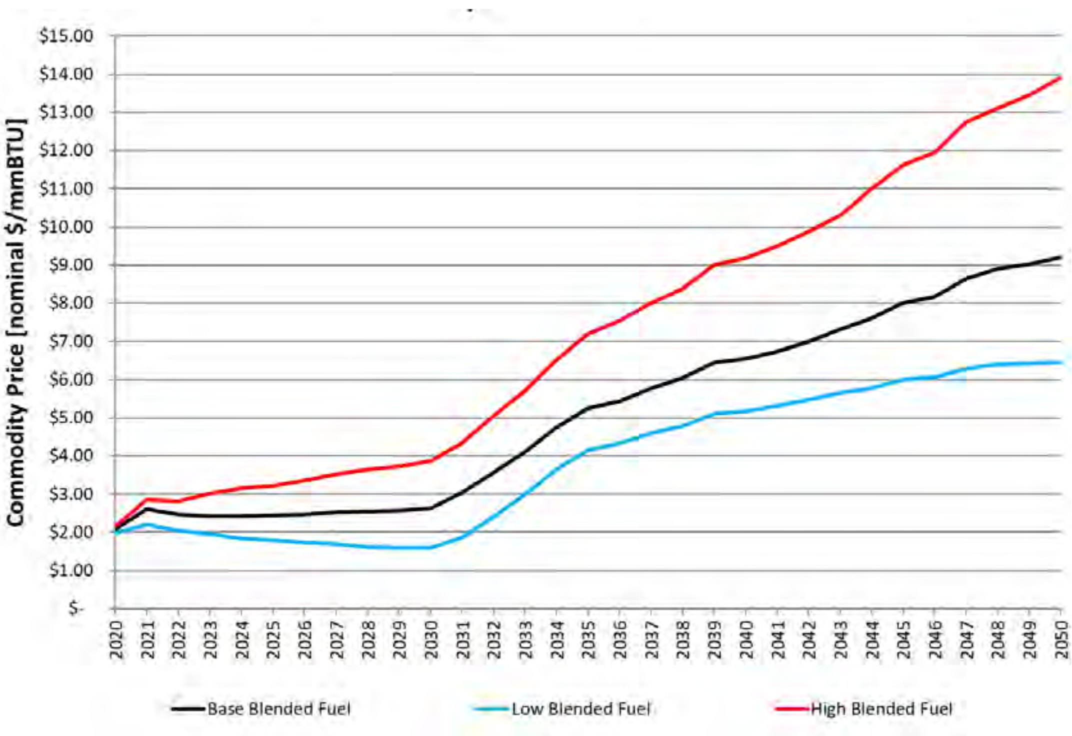
DEC continues to rely on 10-year market purchases of natural gas and 5-years of market observations of coal prices before transitioning to fundamental fuel forecasts for development of the IRP.

- Natural Gas based on market prices from 2021 through 2030 transitioning to 100% fundamental by 2035.
- Coal based on market observations through 2024 transitioning to 100% fundamental by 2030.

In order to test the effects of changing fuel prices on resource selection and portfolio value, DEC developed high and low natural gas prices. By only changing natural gas prices, the impact on resource selection (CC vs CT vs Renewables) and dispatch (coal vs gas) can be evaluated. The natural gas prices evaluated in the 2020 IRP are shown in the chart below.

FIGURE A-2

NATURAL GAS PRICE SENSITIVITIES



The high and low natural gas price sensitivities were developed using a combination of high and low market and fundamental projections. The high and low market natural gas prices were developed using statistical analysis on market quotes to determine a 10th and 90th percentile probability. The high and low fundamental natural gas prices were derived using the base fundamental forecast and the EIA's 2020 Annual Energy Outlook (AEO) natural gas price forecasts from its Reference Case, Low Oil and Gas Supply Case, and High Oil and Gas Supply case.

CAPITAL COST SENSITIVITIES

Three capital cost sensitivities were performed. As discussed in Appendix G, most technologies include technology specific Technology Forecast Factors which were sourced from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2020 which provides costs projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS) utilized by the EIA for the AEO. More nascent technologies, such as battery storage and, to a lesser extent, PV solar, have relatively steep projected cost declines over time compared to more established technologies such as CCs and CTs. The first capital cost sensitivity evaluated the impact on the expansion plan of lower and higher reductions in solar PV costs as shown in Table A-6.

TABLE A-6

SOLAR & SOLAR + STORAGE CAPITAL COST SENSITIVITIES – PROJECTED PERCENT COST REDUCTION FROM 2020 TO 2029 BASED ON REAL 2020$

	LOW	BASE	HIGH
SOLAR PV % REDUCTION IN COST	-54%	-40%	-20%
SOLAR PV + STORAGE % REDUCTION IN COST	-61%	-46%	-26%

The second capital cost sensitivity evaluated the impact of reducing the asset life of a CT or CC from 35-years to 25-years. While the Company believes that natural gas is necessary for transitioning to a net-zero CO_2 emission future, this sensitivity considered the risk of new natural gas assets realizing an earlier than normal retirement.

The final capital cost sensitivity evaluated a reduction in battery storage costs to determine the impact on CT versus battery selection. Currently, the Company assumes that battery storage costs will decline by approximately 45% over the next decade. This sensitivity increases the cost decline to approximately 55%.

HIGH ENERGY REDUCTION FROM DEP'S DSDR PROGRAM

While the IRP base planning assumptions include energy reductions for DEP's Distribution System Demand Response Program, additional historical measurement and verification shows potential for further energy reduction from this program. The test year used for the IRP, 2018, provided approximately 100,000 MWhs of energy reduction by 2025, when the program would be fully implemented. Using a test year of 2017, the program could reduce energy by up to 400,000 MWhs, or 0.6% reduction in load for DEP, by the same timeframe. High level estimates suggest that this additional energy reduction, if realized, could result in approximately 140,000 ton of CO_2 reduction per year. While this additional energy reduction would further lower load on the DEP side, the reduction in load could also impact the energy transfer between utilities as part of the JDA. The additional reduction in energy will not impact the programs peak reduction capacity.

TECHNOLOGY ADVANCEMENTS

In some instances, certain technologies may not be considered "economic" within the planning horizon. However, these technologies may show significantly more value beyond the planning horizon particularly under strict carbon policies. Additionally, these resources may be required to achieve certain policy goals prior to the end of the planning horizon. For these reasons, the following technologies were evaluated in the 2020 IRP.

- **Small Modular Reactors (SMR) –** In order to achieve climate goals such as 70% CO_2 reduction by 2030 and net-zero carbon reduction by 2050, zero-emitting, load following resources (ZELFR) will be required. DEC evaluated SMRs as an example ZELFR within the planning horizon in several portfolios.

- **Offshore Wind –** While offshore wind was included in the Company's High Renewable sensitivity, several portfolios significantly increased the penetration of this resource to determine its impact on achieving 70% carbon reduction by 2030. This increase in penetration is reasonable, and is a likely outcome, if offshore wind is developed off the coast of the Carolinas.

- **Pumped Storage Hydro –** As non-dispatchable resources such as solar and wind become prevalent on the system, the need for storage increases to avoid curtailment and optimize utilization of these carbon free resources. As shown in the Company's Capacity Value of Battery Storage study, the value of short duration storage erodes rapidly as additional MW of similar storage durations are added. For this reason, pumped hydro storage that can provide 8 or more hours of charging and generating was considered in cases that included renewable energy beyond that found in the base case.

ENERGY STORAGE

150 MW of 4-hour Lithium ion batteries are included in all portfolios as placeholders for future assets to provide operational experience on the DEC system. These placeholders represent a limited amount of grid connected battery storage projects that have the potential to provide solutions for the transmission and distribution systems with the possibility of simultaneously providing benefits to the generation resource portfolio.

In addition to these placeholders, solar coupled with storage was included in all of the various renewable cases and was available for selection in the capacity expansion model. Furthermore, as discussed in Chapter 11, the Company studied the impact of replacing CTs with 4-hour battery storage during various points over the planning horizon. Finally, as part of several of the portfolios presented later in this appendix, battery storage was viewed as a key resource in the presence of increasing renewable penetration and the efforts to achieve certain carbon reduction goals, as well as, in cases where new natural gas generation was not an available resource.

JOINT PLANNING

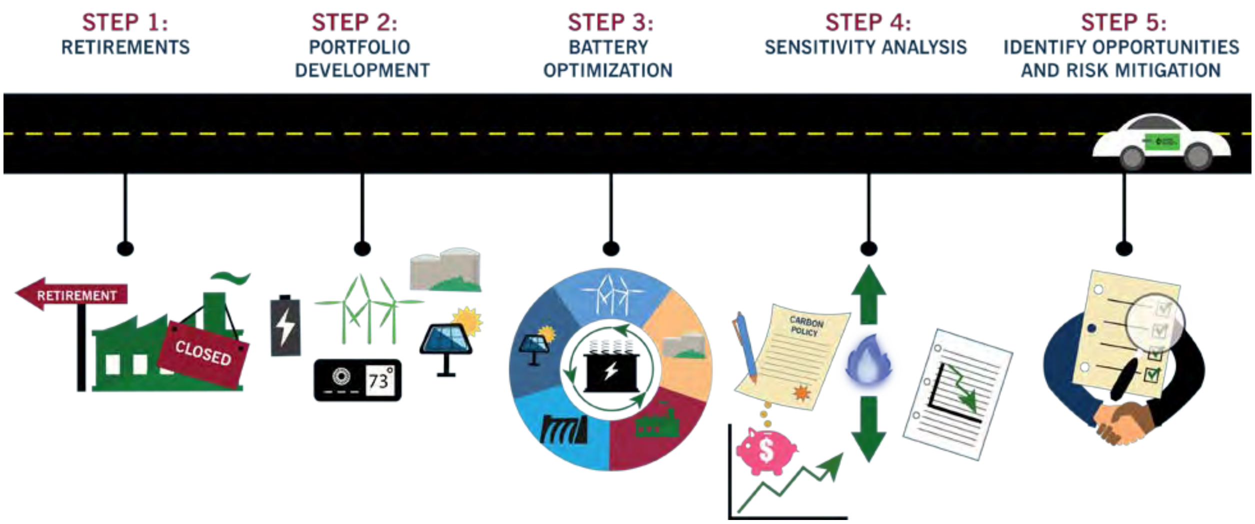
As required through the Joint Dispatch Agreement, DEC and DEP must plan to meet future capacity needs as individual utilities without the ability to share firm capacity. However, DEC performed a sensitivity assuming joint planning between DEC and DEP to investigate the benefits of shared resources and how new generation could be delayed. The Joint Planning analysis is discussed later in this appendix.

BASE CASE PORTFOLIO DEVELOPMENT AND RESULTS

The Base Cases utilize the company's current planning assumptions to determine least cost portfolios in scenarios with and without policy on carbon emissions from the electric generation fleet. These two (2) portfolios include the most economic retirement dates of the company's coal units, as discussed in Chapter 11. These portfolios utilize base planning assumptions for energy efficiency and demand response forecasts to reduce peak demand before incremental resource additions are evaluated. After the Base Case portfolios have been screened into the portfolio through the capacity expansion model, batteries were evaluated in a production cost model to optimize inclusion in the portfolios. Base Cases were then evaluated in sensitivity analysis to inform development of alternative portfolios. Below is a simplified process flow diagram for development of the base planning portfolios.

FIGURE A-3

SIMPLIFIED PROCESS FLOW DIAGRAM FOR BASE CASE PORTFOLIO DEVELOPMENT AND SENSITIVITY ANALYSIS



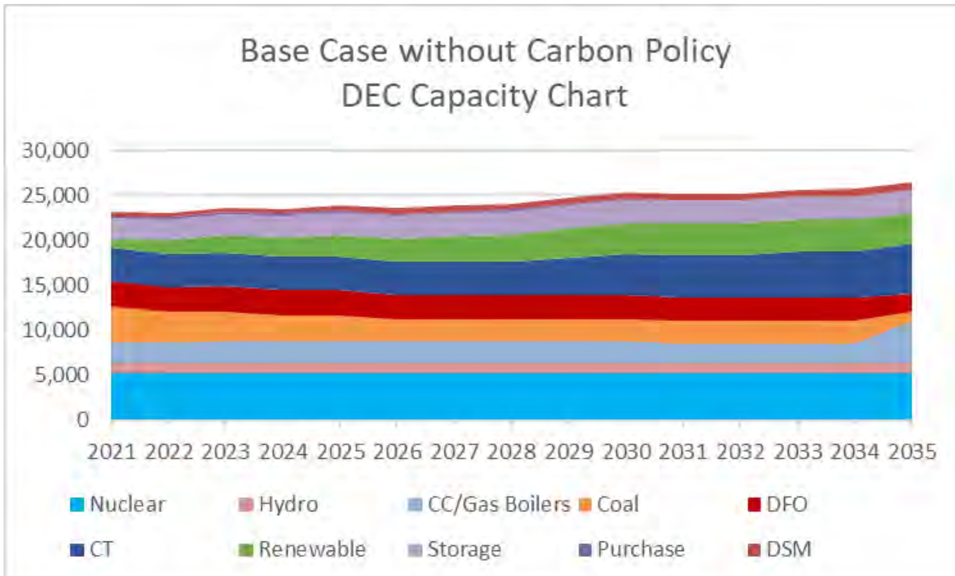
BASE CASE WITHOUT CARBON POLICY

PORTFOLIO AND RESULTS DISCUSSION

The Base Case without Carbon Policy largely selects new natural gas generation to replace retiring coal generation. This portfolio adds nearly 4,300 MW of gas capacity to replace the retiring 3,700 MW of coal capacity and meet load growth. With the utility's current capacity position along with this IRP's lower, but still growing winter peak demand, the first traditional capacity addition is not needed until 2029, shortly after the retirement of Cliffside 5. There are no model-selected solar additions in this portfolio, which indicates that above the forecasted solar additions, the system would likely require additional economic support from either a carbon price or other supporting energy policy to continue adding renewable generation to the system. Through the battery optimization of this Base Cases, it was found that batteries were not economic within the IRP planning horizon.

FIGURE A-4

DEC CAPACITY CHART - BASE CASE WITHOUT CARBON POLICY



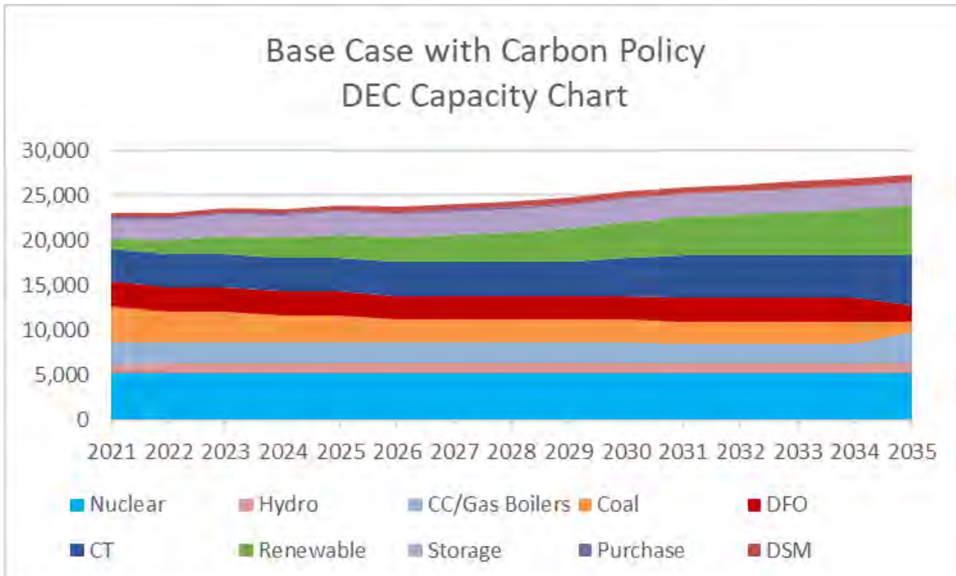
BASE CASE WITH CARBON POLICY

PORTFOLIO AND RESULTS DISCUSSION

The Base Case developed under the assumption of future carbon policy results in a more diverse set of resource additions than its no carbon policy counterpart. This case adds 1,200 MW less natural gas generation by 2035 compared to the no carbon policy case, and instead adds 1,200 MW of additional solar and solar plus storage, and a small amount of wind, to meet energy and capacity need created by retiring coal. The addition of the carbon policy, in the form of a tax, drives the model-selected addition of these non-carbon emitting resources in this year's IRP. Even with the increased amount of intermittent resources and the steep decline in battery cost, this case found battery additions to be not economic within the IRP planning horizon. The results are due in part to the substantial amount of energy storage already on the DEC system in the form of the Company's pumped storage hydro fleet.

Corrected 11.06.2020

FIGURE A-5
DEC CAPACITY CHART - BASE CASE WITH CARBON POLICY



Below in Table A-7 is a comparison of the Base Case capacity expansion results.

TABLE A-7

BASE CASE CAPACITY CHANGES WITHIN IRP PLANNING HORIZON

	BASE CASE WITHOUT CARBON POLICY	BASE CASE WITH CARBON POLICY
PORTFOLIO	A	B
Coal Retirements [MW]	3,754	3,754
Incremental Solar [MW]┼	2,720	4,970
Incremental Onshore Wind [MW]┼	0	150
Incremental Offshore Wind [MW]	0	0
Incremental SMR Capacity [MW]	0	0
Incremental Storage [MW]╪	351	595
Incremental Gas [MW]	4,276	3,052
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW]	1,222	1,222

┼Combined forecasted and model-selected incremental additions by the end of 2035.

╪Includes Standalone Storage and Storage at Solar plus Storage sites

* Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour.

SENSITIVITY ANALYSIS RESULTS

Following the development of the Base Case portfolios, sensitivities were run to inform the development of the alternative portfolios. Table A-8 presents an overview of the year certain resources were selected by the capacity expansion model in each of sensitivities. Red indicates an earlier date than the Base Case with Carbon Policy, green indicates a later date than the Base Case with Carbon Policy, and orange indicates the resource was not selected during the planning horizon.

TABLE A-8

MATRIX OF FIRST SELECTION OF RESOURCES

	BASE		EE		DSM		LOAD		FUEL PRICE		RENEWABLES		SOLAR COST	
	W/ CO_2 POLICY	W/O CO_2 POLICY	HIGH	LOW	HIGH	LOW	HIGH	LOW	HIGH	LOW	HIGH	LOW	HIGH	LOW
CT	2030	2030	2030	2035	2031	2031	2035	2035	2035	2035	2030	2035	N/A	2030
CC	2035	2035	2035	2029	2035	2026	2029	2031	2030	2029	2035	2029	2029	2035
Standalone Solar	2025	N/A	2025	2025	2025	2025	2025	2025	2025	2027	2027	2027	2028	2025
Solar Plus Storage	2029	N/A	2029	2030	2029	2029	2029	2030	2028	2032	2032	2030	N/A	2026
Onshore Wind	2035	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2034	N/A	2035	N/A	N/A	N/A

Several observations from the sensitivity analysis are discussed below:

- **Timing of new natural gas generation –** The timing for the need of new natural gas generation does not change significantly across cases. New gas generation is accelerated when load is higher than the base (High Load and Low EE); other resources are available later or in lesser quantities (Low DSM, Low Renewables, High Solar Cost); or natural gas prices are lower than the base.

- **Type of new natural gas generation –** While CTs are selected as the first natural gas resource in the base case, in many other cases CCs are selected first. This likely signifies that there is little difference between the value of CTs and CCs as the first resource. This variation may also signify that DEC is somewhat energy limited. For instance, Low EE, Low Renewables, High Solar Cost all lead to a greater demand for non-energy limited resources earlier in the planning horizon. In those cases, CCs are selected first. In the cases of High EE, High Renewables, and Low Solar cost, the presence of solar and solar plus storage or the reduction in energy demand make energy from gas generation less critical, and CTs are selected before CCs. The resource mix in DEP also likely plays a role in the resource selection in DEC, and vice versa, as the Joint Dispatch Agreement allows for the transfer of energy between the two utilities. While the capacity expansion model cannot optimize capacity needs between the two utilities, it can optimize energy resources to take advantage of the JDA.

- **Solar Energy –** Solar energy could not have been accelerated prior to 2025 due to the 300 MW/year interconnection constraint placed on solar. However, solar plus storage could have been selected earlier than 2029; either in place of, or in conjunction with, standalone solar. Solar plus storage was accelerated in the case of higher fuel prices and lower solar costs. Solar plus storage was delayed if its energy or capacity was not needed or was met by other resources which occurred in most cases where CCs were selected prior to CTs.

- **Wind Energy –** Onshore Carolinas Wind was not selected in most cases. This likely signifies that in DEC, the resource is providing marginal value. In the base case, the capacity and energy from the wind resource helps meet a capacity need at the end of the planning horizon while providing valuable carbon free energy at the time of an increasing CO_2 tax. In most other cases, that value is limited as other resources such as EE, DSM, Solar, and natural gas are providing that capacity and energy value in front of onshore wind generation.

The following tables (Table A-9 and Table A-10) provide greater detail on the impacts of each sensitivity performed including impact to PVRR, CO_2 emissions by 2030 and 2035, and resource selection through 2035.

TABLE A-9

PVRR ANALYSIS OF SENSITIVITIES THROUGH 2050, $ BILLIONS

	MASS CAP/CAP AND TRADE	CARBON TAX
Base CO_2	$46.8	$55.1

	MASS CAP/CAP AND TRADE			CARBON TAX		
	PVRR	DELTA FROM BASE CASE WITH CARBON POLICY	PERCENT CHANGE FROM BASE CASE WITH CARBON POLICY	PVRR	DELTA FROM BASE CASE WITH CARBON POLICY	PERCENT CHANGE FROM BASE CASE WITH CARBON POLICY
Base CO_2 - High Load	$47.0	$0.2	0.4%	$55.4	$0.3	0.6%
Base CO_2 - Low Load	$44.3	-$2.5	-5.3%	$51.2	-$3.9	-7.1%
Base CO_2 - High Fuel	$52.8	$6.0	12.8%	$60.6	$5.5	10.0%
Base CO_2 - Low Fuel	$42.6	-$4.2	-9.0%	$51.5	-$3.5	-6.4%
Base CO_2 - High Renewables	$49.2	$2.4	5.1%	$55.9	$0.8	1.5%
Base CO_2- Low Renewables	$45.8	-$1.0	-2.2%	$54.5	-$0.6	-1.1%
Base CO_2 - High EE	$46.7	-$0.1	-0.2%	$54.8	-$0.2	-0.4%
Base CO_2 - Low EE	$46.7	-$0.1	-0.2%	$55.1	$0.0	0.0%
Base CO_2 - High DR	$47.0	$0.2	0.4%	$55.2	$0.2	0.3%
Base CO_2 - Low DR	$47.4	$0.6	1.2%	$56.2	$1.1	2.1%
Base CO_2 - High Renew Cost	$46.1	-$0.8	-1.6%	$55.5	$0.4	0.8%
Base CO_2 - Low Renew Cost	$46.1	-$0.7	-1.5%	$54.3	-$0.8	-1.4%
Base CO_2 - 25-Year Gas	$46.8	$0.0	0.0%	$55.6	$0.6	1.0%
Base CO_2 - Pumped Storage	$48.5	$1.7	3.6%	$56.3	$1.2	2.2%
Base CO_2 - DEP's High Energy DSDR	$46.8	$0.0	0.0%	$55.1	$0.0	0.0%

Min	$42.6	-$4.2	-9.0%	$51.2	-$3.9	-7.1%
Median	$46.8	$0.0	0.0%	$55.2	$0.2	0.3%
Max	$52.8	$6.0	12.8%	$60.6	$5.5	10.0%

TABLE A-10

DEC SENSITIVITY ANALYSIS RESULTS

	BASE		EE		DSM		Load		Fuel Price		Renewables		Solar Cost	
	w/ CO_2 Policy	w/o CO_2 Policy	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low
CO_2 Reduction by 2030 / 2035	59% / 62%	56% / 53%	60% / 62%	60% / 62%	60% / 62%	59% / 62%	61% / 63%	63% / 70%	60% / 59%	59% / 60%	61% / 66%	60% / 61%	59% / 61%	60% / 63%
2035 Winter Peak Demand	19,473	19,473	19,426	19,567	19,473	19,473	19,580	19,235	19,473	19,473	19,473	19,473	19,473	19,473
EE	377	377	424	283	377	377	377	377	377	377	377	377	377	377
DSM	845	845	845	845	1,428	688	845	845	845	845	845	845	845	845
Generation Added Over Planning Horizon (Nameplate Winter MW) ┼														
Gas Generation	3,052	4,276	3,052	3,362	3,052	4,733	3,362	2,905	3,052	3,362	3,052	3,362	3,672	3,362
Solar‡	5,410	3,493	5,410	5,368	5,410	5,410	5,410	5,368	5,518	5,068	6,796	4,500	4,393	5,668
Wind	150	0	0	0	0	0	0	0	0	0	150	0	0	0
Storage	558	351	558	539	558	558	558	539	576	501	631	329	351	614

┼ MWs represent availability on January 1, 2035.

‡Total Solar; Assumes 0.5% annual degradation.

Corrected 11.06.2020

Several key takeaways from the sensitivity analysis include:

- Without a carbon policy, neither solar nor wind resources are economically selected.

- It appears that High EE is cost effective versus the base. Some of the value arises from avoiding onshore wind in the 2035 timeframe. The capacity and energy provided by the higher levels of EE is more valuable than the wind generation in the 2035 timeframe. There is executability risk with achieving these levels of energy efficiency. For this reason, these stretch targets were not included in the Base with and without Carbon Policy cases but were included in the aggressive CO_2 reduction portfolios. Future IRPs will include updated efficiency savings estimates and program cost forecasts as the Company continues to pursue delivering its portfolio of energy efficiency programs inclusive of working with stakeholders in the EE collaborative and industry experts to identify additional cost-effective programs.

- In cases where incremental capacity is needed, such as the High Load Forecast and Low EE and DSM sensitivities, gas generation is the preferred source of capacity versus solar plus storage or onshore wind generation.

- As expected, higher fuel prices, lower solar costs, and carbon policy drive increases in solar and solar plus storage resources.

- A review of the sensitivity PVRR analysis highlights that changes in fuel cost had the greatest impact on total PVRR. While the other variables influence incremental energy and resource selections, fuel presents the greatest cost opportunity and risk. The range of uncertainty supports continued diversity in fuel type and regional supply to minimize these risks.

Several other sensitivities investigating the value of Pumped Storage Hydro, a 25-year life for natural gas assets versus the base assumption of a 35-year life, and lower battery storage costs were also developed.

PUMPED STORAGE HYDRO

As discussed previously, as non-dispatchable renewable resources increase in number on the DEC system, longer duration energy storage will become critical to maintaining a reliable system. The sensitivity performed in this case was with Base Renewables along with DEC and DEP operating as separate utilities with current transmission capacity between the two utilities which limits the value of additions PSH. A scenario with higher renewable penetration and increased transmission capability between the two utilities would likely increase the value of PSH. The Company believes that under certain climate goals and carbon reduction policies, incremental PSH would be a valuable addition to the fleet.

25-YEAR NATURAL GAS ASSETS

There was little change to the expansion plan in the case where the asset life of natural gas CCs and CTs was reduced to 25-years from 35-years. In DEC, neither solar nor solar coupled with storage was accelerated to account for this change, however additional onshore wind generation was accelerated from just beyond the planning horizon to the 2033 timeframe. Timing of CC and CT generation did fluctuate with a CC accelerating from outside the planning horizon into the last year of the planning horizon, and a similar capacity of CTs slipping out of the planning horizon.

BATTERY STORAGE COSTS

In the Base Case with Carbon Policy, battery storage was determined not to be economic versus CT assets within the planning horizon. To test the impact of lower battery storage costs, the Company tested the PVRR cost effectiveness of a CT vs 4-hour Li-ion battery storage that was 15% lower cost than the original planning assumption. In DEC, the opportunity to replace a CT with battery storage occurs in 2028, 2030, and 2034. Even at the lower battery costs, the CT was the more economic option; however, by 2034 the battery became the more economic choice. Regardless of this exercise, as noted in Chapter 11, at the time new resources are needed on the DEC system, the Company will solicit bids to fill the resource gap as part of the CPCN process for new generation resources. Only then, will the true costs of competing technologies be fully known.

5. DEVELOPMENT OF ALTERNATIVE PORTFOLIO CONFIGURATIONS

While Base Case with and without Carbon Policy provide insight into the larger theme of the impact of carbon policies to drive reductions from a business as usual case, the company's approach in this IRP was to analyze multiple pathways that align to the of interest to stakeholders. These portfolios attempt to achieve desired outcomes of ceasing to burn coal in the Company's generation fleet, meeting aggressive carbon reductions goals, and in one scenario transition the fleet without the deployment of new gas generation. The work described in the previous section with respect to sensitivity analysis also helped inform the development of these pathways. While each of these pathways attempts to accomplish its own desired outcomes, the detailed examinations also help quantify tradeoffs of total costs of the implementation and operation of the pathway, pace of change and impact to the average residential monthly bill, dependency on technological development and deployment, and dependency on policy to enable the transition. This section highlights the additional portfolios analyzed and discusses some of the different requirements for each of the portfolios.

ALTERNATIVE PLANNING CASE RESULTS

EARLIEST PRACTICABLE COAL RETIREMENTS

EARLIEST PRACTICABLE COAL RETIREMENT ANALYSIS

In the 2020 IRP, the Company evaluated the potential factors that would restrict the Utility from retiring (or ceasing to burn coal at) the current coal fleet at their earliest practicable dates. To cease coal operations at nearly 7,000 MWs in DEC as earliest as practicable, this analysis suspends traditional "least cost" economic planning considerations, focusing on procurement and construction timelines for replacement capacity. The evaluation of these accelerations is often restricted by infrastructure to enable the replacements. Some of the most impactful factors contributing to earliest practical retirement dates are discussed below:

UTILITY PLANNING RESERVE MARGIN LENGTH

As with the most economic coal retirement analysis, the earliest practicable coal retirements also considered immediate planning reserve margin length of the utility to retire the capacity without replacement. To the extent possible, units were accelerated based on the available capacity length beyond the minimum planning reserve margin.

RETIRING COAL SITE TRANSMISSION

After retirements with excess planning capacity, the coal sites were considered for transmission grid impacts. With over 60-years of operations in the Carolinas, some the existing coal sites have become critical for reliability and stability of the grid. Retirement of these stations without replacement onsite often requires additional transmission projects which can further lead to delays in retirement of the coal fleet. To the extent possible, replacement generation in the Earliest Practicable case was located at the site of the retiring coal plants to avoid transmission projects which would further delay the retirement of these assets if replacement generation was built offsite.

INTERCONNECTION TO TRANSMISSION SYSTEM OF REPLACEMENT GENERATION

Also contributing to the ability to accelerate retirement of these assets is the need for infrastructure associated with new replacement generation sites, usually consisting of transmission interconnection, and possible requirements for gas and water infrastructure. The current process for getting through the interconnection queue could be significant given the size of the queue. Once interconnection studies are complete, depending on the outcome of those studies, transmission upgrades to interconnect the replacement capacity may then be required which can add years to the process of replacing existing generation. These timelines were accounted for when considering options for offsite replacement capacity.

LEVERAGING EXISTING INFRASTRUCTURE

Leveraging existing infrastructure rather than constructing new generation at greenfield sites can enable accelerated retirement of these assets. Siting replacement capacity generation at existing sites can alleviate the need for new land, water sources and reduce transmission upgrades that may be required to maintain grid stability should generation cease to exist at existing coal sites and leverage gas infrastructure already in place at many DEC coal sites. Where necessary, additional consideration was taken for incremental interstate gas pipeline to provide adequate gas supply to certain sites.

TABLE A-11
EARLIEST PRACTICABLE COAL RETIREMENT DATES OF DEC COAL PLANTS

	BASE CASE MOST ECONOMIC RETIREMENT YEAR (JAN 1)	EARLIEST PRACTICABLE COAL RETIRMENT YEAR (JAN 1)	CONSTRAINING FACTOR
Allen 2 – 4	2022	2022	Not Applicable – Retired with Capacity Length
Allen 1 & 5	2024	2024	Transmission project to enable retirement
Cliffside 5	2026	2026	Construction of onsite or offsite capacity
Marshall 1 – 4	2035	2028	Construction of onsite gas capacity
Belews Creek 1 & 2	2039	2029	Construction of onsite gas capacity, interstate pipeline
Cliffside 6	2049	2049*	*Conversion to 100% Gas in 2030, eliminating coal firing capabilities

FACTORS INFLUENCING EARLIEST PRACTICABLE COAL RETIREMENT DATES

As discussed, the primary consideration in the development of the "earliest practicable" coal retirement dates is the timeline to bring replacement resources into service. In DEC, with the exception of the coal units at Allen Station which can be retired without immediate capacity replacements, further coal retirements would necessitate replacement resources to be in service prior to retirement. Demand-side efforts identified in the IRP help to reduce the amount of resources needed to supply a growing customer base. However, the net demand and energy forecast after all demand-side initiatives is still positive. Hence any retirement of existing capacity resources creates a need for reliable replacement capacity to maintain overall system reliability. With respect to market purchases, it was assumed that in the aggregate expiring purchase contracts of existing traditional fossil resources and renewable energy resources where either extended or replaced in-kind through future RFP activities. This assumption further reduces the need for additional resources that would otherwise be required from the expiry of current purchase power contracts. Additional capacity purchases from neighboring balancing areas was not assumed eligible for replacement capacity in this analysis given the uncertain nature of the availability and cost of such potential purchases as well as the associated transmission requirements to bring in such purchases. More discussion on the ability and costs to increase transfer limits with neighboring service territories is outlined in Chapter 7.

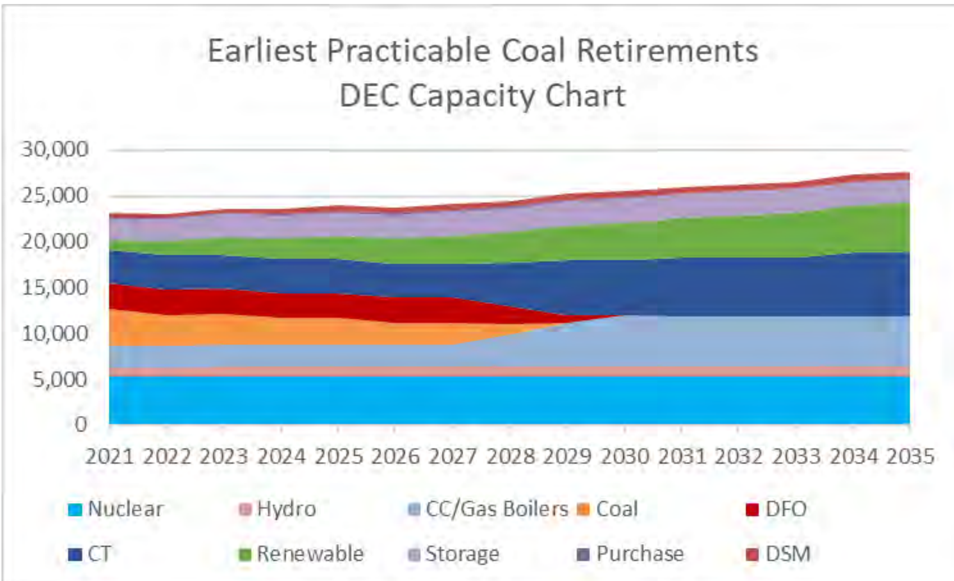
Finally, the consideration of earliest practicable coal retirement dates assumes a continued aggressive growth in year-over-year renewable resources as depicted in the Base with Carbon Policy portfolio. After first considering the total impact of demand-side activities, market purchases and renewable additions it was determined that additional reliable capacity would be required in order to enable coal retirements while maintaining adequate planning reserves as discussed in Chapter 9. As a result, to arrive at the earliest practicable coal retirement dates requires minimizing the time to site, permit, construct and obtain regulatory approval for replacement capacity resources and supporting infrastructure. As previously mentioned, for the "earliest practicable" portfolio this time lag was assumed to be minimized by replacement resources being sited largely at the retiring coal facility locations to leverage existing land, water and transmission infrastructure.

PORTFOLIO AND RESULTS DISCUSSION

With the earliest practicable retirement dates established, the capacity expansion model was run to optimize the replacement capacity needs while adhering to the prescribed replacements required to enable retirements. This plan utilizes base renewable, energy efficiency and demand response projections, as the high integration rate and high energy efficiency and demand response program penetration may not be practicable. The plan adds a combined cycle and two (2) blocks of CTs in 2028, assumed to be at Belews Creek, and Marshall respectively, leveraging existing pipeline capacity, existing transmission interconnection, and avoiding transmission upgrades for retiring Marshall. The following year the plan adds a second combined cycle at Belews Creek and additional 1,400 MWs of CT at an undesignated location to meet capacity planning reserves in 2029 and retires the Belews Creek coal units. This case maintains coal operations at Cliffside 6 through 2029, when it is converted to 100% gas operations, to ensure flexibility and reliability of the system through this transition. While these earliest practicable dates are technically feasible, it would likely take supporting policy to effectuate given the complexities in the siting, permitting, construction and regulatory approval for such a large amount of resources in that period of time.

FIGURE A-6

DEC CAPACITY CHART - EARLIEST PRACTICABLE COAL RETIREMENTS



70% CO_2 REDUCTION: HIGH WIND

The 70% CO_2 Reduction: High Wind portfolio outlines a pathway to reduce CO_2 system emissions by 70% by 2030, from a 2005 baseline, by tapping into offshore wind resources off the coast of the Carolinas. This scenario demonstrates the necessary investment requirements and procurement, engineering, and construction challenges to bring this carbon-free resource into the portfolio to reduce the overall emissions of the system. This plan highlights the benefits of bringing these resources into the company's service territory, and illustrates that the retirement of carbon intense resources, such as coal, alone is not enough to reach these lofty goals, but requires access to lower and carbon-free energy.

PORTFOLIO AND RESULTS DISCUSSION

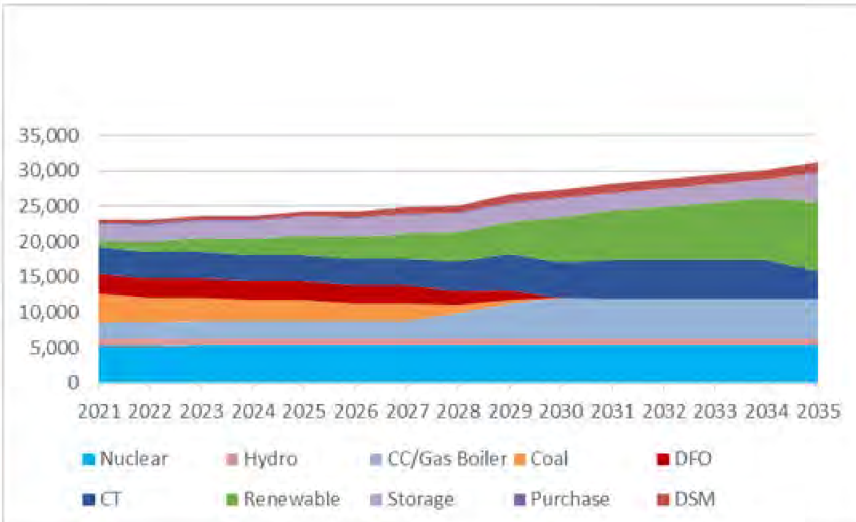
The assumption of earliest practicable retirement dates underlies this plan to enable further reduction of carbon emissions by 2030. This plan also assumes high renewables, energy efficiency, and demand response projections, to provide carbon-free capacity and energy to further reduce CO_2 emission. Critically, the earliest practicable retirement dates, along with high levels of renewable penetration (4,000 MWs of solar as a combined system above the Base Case with Carbon Policy by 2035), is not enough to achieve 70% CO_2 reduction and additional carbon-free resources, such as offshore wind are needed.

As with the previous case, gas generation will be required to enable these retirements and provide system flexibility and reliability while further reducing carbon emissions of the system.

This plan assumes 1,200 MWs of offshore wind are incorporated into the DEC service territory by 2030. To maintain enough capacity reserves before the offshore wind can be constructed and connected to the system, one Belews Creek unit's retirement is delayed one year from the earliest practicable retirement dates to 2030. Due to the geographical location of the offshore wind resource, significant transmission infrastructure will be required to deliver this energy to the DEC service territory. While offshore wind can provide bulk carbon-free energy, it does not provide one-for-one reliability equivalency. As an intermittent resource, the system will have to respond to variances in output from the offshore wind farm. Additionally, offshore wind is estimated to provide approximately 54% of its nameplate capacity towards meeting DEC's winter peak demand. While offshore wind capacity helps meet DEC's energy needs, the Company still requires traditional gas generation to accelerate coal retirements in this case and provide the needed capacity reserves to fulfill the Company's obligation to serve load.

While this portfolio achieves its intended outcome, it will likely require accelerated technological deployment enhancements and policy support to enable this pathway. While offshore wind is not necessarily a new technology, deployment in the US at large scale is yet to be demonstrated. The cost of the resource and getting the energy from coastal Carolinas to the load centers in the central part of the states will present implementation challenges. These challenges can be mitigated with effectively political and regulatory support and policy.

FIGURE A-7
DEC CAPACITY CHART - 70% CO_2 REDUCTION: HIGH WIND



70% CO_2 REDUCTION: HIGH SMR

The 70% CO_2 Reduction: SMR portfolio outlines a pathway to reduce CO_2 system emissions by 70% by 2030, from a 2005 baseline, by deploying advanced nuclear technologies by the end of this decade. This scenario demonstrates the necessary investment requirements and procurement, engineering, and construction challenges to bring this carbon-free resource into the portfolio to reduce the overall emissions of the system. This plan highlights the benefits of bringing advanced nuclear technologies into the Company's service territory, and illustrates that the retirement of carbon intense resources, such as coal, alone is not enough to reach these lofty goals. As with the 70% CO_2 Reduction: High Wind pathway, 70% CO_2 emissions reduction by 2030 requires access to diverse types of lower carbon and carbon-free energy.

PORTFOLIO AND RESULTS DISCUSSION

As with the previous 70% CO_2 Reduction case, the assumption of earliest practicable retirement dates underlies this plan, enabling this plan to further reduce carbon emissions by 2030. Similarly, in this case, earliest practicable retirement dates, along with high levels of renewable penetration (nearly 4,000 MWs of solar as a combined system above the Base Case with Carbon Policy by 2035), is not enough to achieve the desired carbon reduction goals and additional carbon free resources, such as small modular nuclear reactors (SMRs) are needed. As with the previous cases, gas generation is required to enable these retirements and provide system flexibility and reliability while further reducing carbon emissions of the system.

This plan assumes the deployment of a 684 MW SMR nuclear plant in DEC by 2030. This technology presents an opportunity for a carbon-free resource that can adjust output up and down to follow trends in load. The addition of SMR capacity in this case is relatively small compared to the DEC system nameplate capacity, but on an energy basis, these dispatchable resources provide a greater density of carbon-free energy as compared to their intermittent renewable counter parts. While the system benefits from these attributes, the ability to license, permit, and construct this emerging technology by 2030 presents a significant challenge. The first full-scale, commercial SMR project is slated for completion at the start of the next decade which is the same time period as the plant in this scenario. To complete a project of this magnitude would require a high level of coordination between state and federal regulators, and even with that assumption, the timeline is still challenged based on the current licensing and construction timeline required to bring this technology to DEC.

While this portfolio achieves its intended outcome, it will require highly effective coordination between the utility, regulatory bodies, and stakeholders to enable this pathway. While nuclear reactors are not a new technology, development and deployment of this design is yet to be demonstrated at large scale. Uncertainty in the project cost and timeline is another factor that will need to be understood before embarking on a groundbreaking project of this magnitude.

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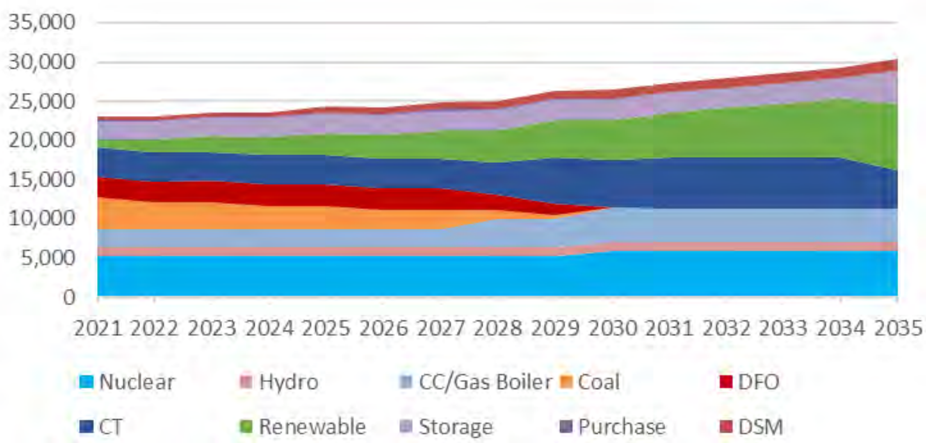
FIGURE A-8

DEC CAPACITY CHART - 70% CO_2 REDUCTION: HIGH SMR



NO NEW GAS GENERATION

There is growing interest from environmental advocates and Environmental, Social, and Corporate Governance (ESG) investors to understand the impacts of no longer relying on natural gas as a bridge fuel to a net-zero carbon future. This scenario explores a pathway, given the proper technological and policy advancements, to bridge the gap between now and the 2050 without building new gas generation. While gas generation is a mature, economical, and reliable resource, the reliance on natural gas as a bridge fuel has been challenged due to its continued reliance on fossil fuels and risks of standing these assets. More discussion about the shortening of the book life of new gas assets and utilizing existing gas infrastructure in a net-zero carbon future were discussed earlier in this appendix and in Chapter 16. To evaluate the cost and operability of the system without gas as a transition fuel, this pathway assumes no new gas generation projects and meets the remaining capacity and energy needs of the DEC system with existing and emerging zero-carbon emitting resources, including solar, storage, wind and SMRs.

PORTFOLIO AND RESULTS DISCUSSION

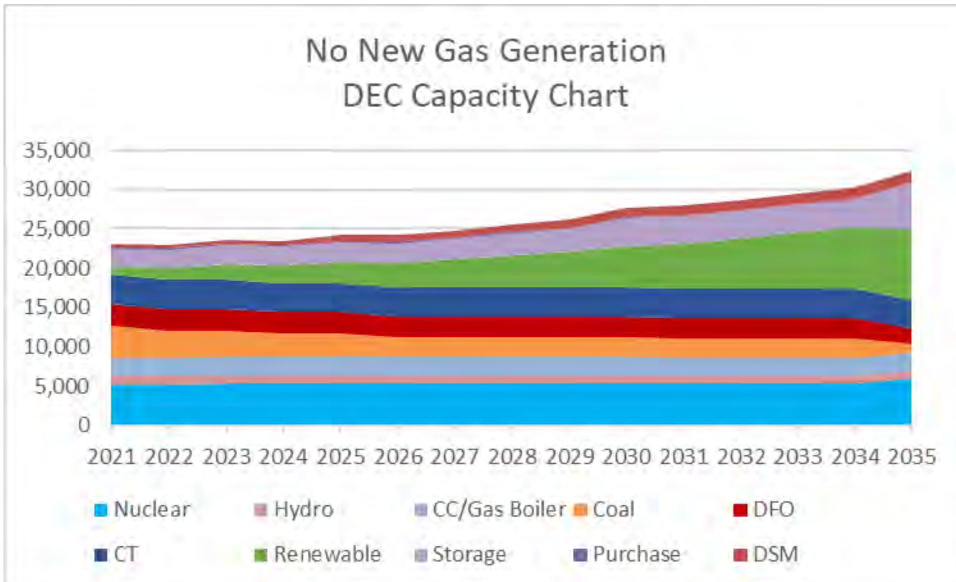
In a scenario, where economical gas generation additions, other than the development of Lincoln County CT #17, are eliminated, and firm winter capacity remains the binding constraint, the system must rely on the existing portfolio until existing technologies, such as batteries, can be built up on the system and emerging technologies become available, before retiring units in the current fleet. In order to allow technologies to reach maturity and decline in price, the most economic coal retirement dates were used in this scenario. This coal capacity, with a secure fuel source and ability to match generation output with demand, will provide the needed capacity until the nascent technologies needed in the mix can be implemented throughout the systems at scale.

In DEC, leveraging high energy efficiency and demand response, and retaining coal capacity through its most economic life, the first capacity need appears upon the retirement of 2,000 MWs at Marshall in 2035. With this capacity length, DEC has more favorable timelines to allow for development of long lead time projects. In this case, with a high penetration of intermittent renewable energy resources, the benefit of additional energy storage rises. While batteries are quickly establishing themselves as assets to a generation fleet, the ability to move bulk energy at a pumped hydro station presents a unique opportunity. New pumped storage, with storage capacity up to twice the duration of current batteries on the market, is implemented in this case to provide 1,600 MWs of long-duration storage, to balance the system and optimize energy costs. When Marshall is retired, there is also a need for energy production. In this plan an SMR is added to the DEC portfolio in 2035. With the ability to wait for these technologies to mature, both operationally and economically, the DEC system benefits from adding this SMR capacity late in the IRP window, providing dispatchable and carbon-free energy.

Within the IRP planning window, the utility can leverage its current capacity length, implementing high levels of EE and DR, and lean on existing resources to bridge the gap without relying on new gas generation. However, soon after the planning window, additional resources begin retiring which will pose additional new challenges in meeting energy and capacity needs until more zero-emitting, load following resources can be deployed.

FIGURE A-9

DEC CAPACITY CHART - NO NEW GAS GENERATION



Below, Tables A-12 and A-13 illustrate the changes to system capacity in the IRP planning horizon for the Base Cases and Alternative Portfolios:

TABLE A-12

BASE CASE AND ALTERNATIVE PORTFOLIO CAPACITY CHANGES WITHIN IRP PLANNING HORIZON

	BASE WITHOUT CARBON POLICY	BASE WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
PORTFOLIO	A	B	C	D	E	F
Coal Retirements [MW]	3,754	3,754	5,974	5,974	5,974	5,974
Incremental Solar [MW]	2,720	4,970	4,970	7,478	7,478	7,478
Incremental Onshore Wind [MW]	0	150	0	1,101	1,101	1,401
Incremental Offshore Wind [MW]	0	0	0	1,338	138	138
Incremental SMR Capacity [MW]	0	0	0	0	684	684
Incremental Storage [MW]ǂ	351	595	595	2,404	2,404	2,406
Incremental Gas [MW]	4,276	3,052	5,647	4,276	3,966	0
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW]*	1,222	1,222	1,222	1,853	1,853	1,853

†Combined forecasted and model-selected incremental additions by the end of 2035.

ǂIncludes Standalone Storage, Storage at Solar plus Storage sites, and Pumped Storage Hydro.

*Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour.

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TABLE A-13

COAL UNIT RETIREMENTS BY PORTFOLIO

	BASE CASE WITHOUT CARBON POLICY	BASE CASE WITHOUT CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: SMR	NO NEW GAS GENERATION
Allen 1 & 5	2024	2024	2024	2024	2024	2024
Allen 2-4	2022	2022	2022	2022	2022	2022
Cliffside 5	2026	2026	2026	2026	2026	2026
Cliffside 6	2049	2049	2049*	2049*	2049*	2049*
Belews Creek 1	2039	2039	2029	2030**	2030**	2039
Belews Creek 2	2039	2039	2029	2029	2029	2039
Marshall 1-4	2035	2035	2028	2028	2028	2035

* Cliffside 6 assumed to be 100% gas fired in all alternate portfolios starting in 2030.

**Delayed from Earliest Practicable Coal Retirement Dates for integration of offshore wind/SMR by 2030.

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6. PERFORM PORTFOLIO ANALYSIS OVER VARIOUS SCENARIOS.

PORTFOLIO PVRR ANALYSIS

Each of the six pathways identified in the portfolio development analysis were evaluated in more detail with an hourly production cost model (PROSYM) under future fuel price and CO_2 scenarios to determine the robustness of each portfolio under varying fuel and carbon futures. The run matrix for the nine scenarios is illustrated in Table A-14 below.

TABLE A-14
PORTFOLIO ANALYSIS RUN MATRIX

	NO CO_2	BASE CO_2	HIGH CO_2
Low Fuel			
Base Fuel			
High Fuel			

The PROSYM model provided the system production costs for each portfolio under the scenarios illustrated above. The model included DEC's non-firm energy purchases and sales associated with the Joint Dispatch Agreement (JDA) with DEP, and as such, the model optimized both DEC and DEP and provided total system (DEC + DEP) production costs. The PROSYM results were separated to reflect system production costs that were solely attributed to DEC to account for the impacts of the JDA. The DEC specific system production costs were then added to the DEC specific capital costs for each portfolio to develop the total PVRR for each portfolio under the given fuel price and CO_2 conditions. The results of this total cost analysis, excluding the explicit cost of the carbon tax to customers (as if the carbon policy were applied as a Cap and Trade program with allowances), is summarized in Table A-15 below.

TABLE A-15

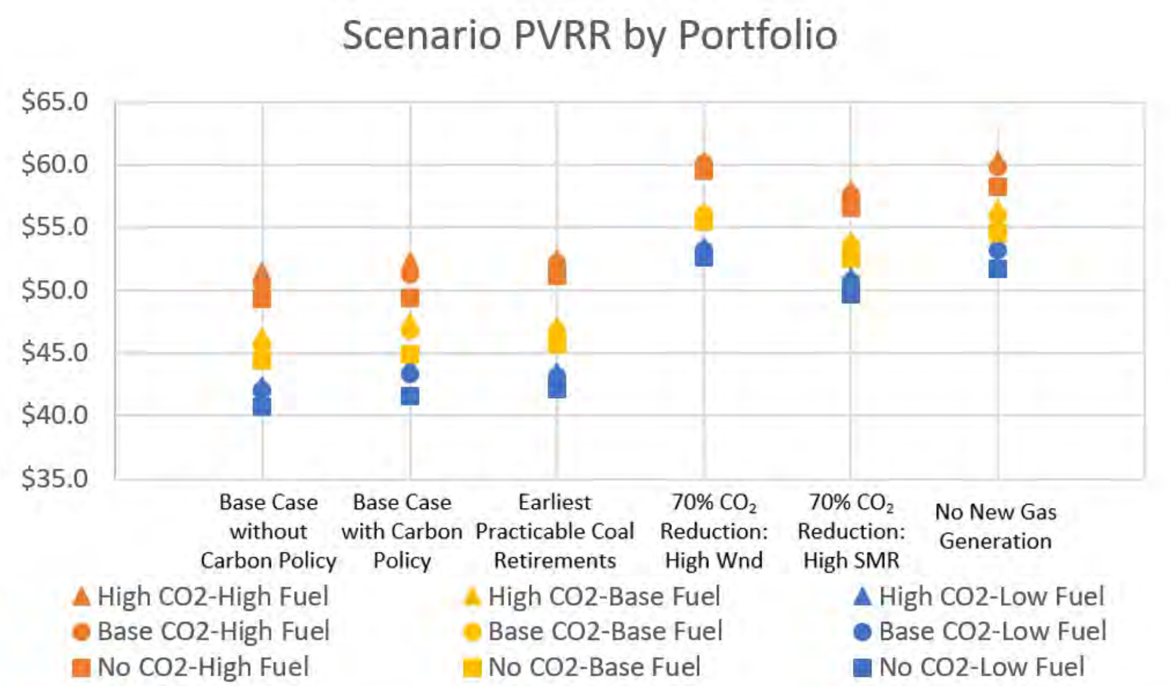
SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, EXCLUDING THE EXPLICIT COST OF CARBON, $ BILLIONS

	BASE PLANNING WITHOUT CARBON POLICY	BASE PLANNING WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO_2-High Fuel	$51.5	$52.3	$52.5	$60.3	$58.0	$60.4
High CO_2-Base Fuel	$46.2	$47.5	$47.1	$56.3	$53.9	$56.5
High CO_2-Low Fuel	$42.4	$43.9	$43.5	$53.4	$51.1	$53.8
Base CO_2-High Fuel	$50.6	$51.2	$52.2	$60.1	$57.6	$59.8
Base CO_2-Base Fuel	$45.8	$46.8	$46.8	$56.1	$53.6	$56.0
Base CO_2-Low Fuel	$42.0	$43.4	$43.1	$53.2	$50.7	$53.2
No CO_2-High Fuel	$49.3	$49.4	$51.2	$59.5	$56.6	$58.3
No CO_2-Base Fuel	$44.4	$44.9	$45.8	$55.5	$52.6	$54.6
No CO_2-Low Fuel	$40.8	$41.6	$42.1	$52.7	$49.7	$51.7

Min	$40.8	$41.6	$42.1	$52.7	$49.7	$51.7
Median	$45.8	$46.8	$46.8	$56.1	$53.6	$56.0
Max	$51.5	$52.3	$52.5	$60.3	$58.0	$60.4

FIGURE A-10

SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, EXCLUDING THE EXPLICIT COST OF CARBON, $ BILLIONS



As seen in Figure A-10 above, each portfolio, when excluding the cost of carbon, have relatively tightly dispersed total PVRR costs, with results coalescing around the natural gas price rather than the underlying carbon price. The plans most affected by the variance in natural gas prices is the Base Case without Carbon Policy, which relies almost exclusively on new gas generation to meet future energy needs. As carbon policy, restrictions on resources, and carbon reduction goals grow, the cost of the plans generally rise, but the dispersion of variance relative to fuel prices shrinks. This is expected, as those plans shift away from natural gas and are naturally less sensitivity to fluctuations in gas price. While the 70% CO_2 reduction and No New Gas Generation cases are less sensitive to gas prices, they are overall more expensive plans, as a result of the costs to add more expensive resources with lower Effective Load Carrying Capabilities (ELCC) and energy output as well as the transmission needed to enable these resources.

Shown summarized in Table A-16 and Figure A-11 below are the results of the same total cost analysis as above, but now including the explicit cost of the carbon tax to customers (as if the carbon policy were applied as tax on carbon emission).

TABLE A-16

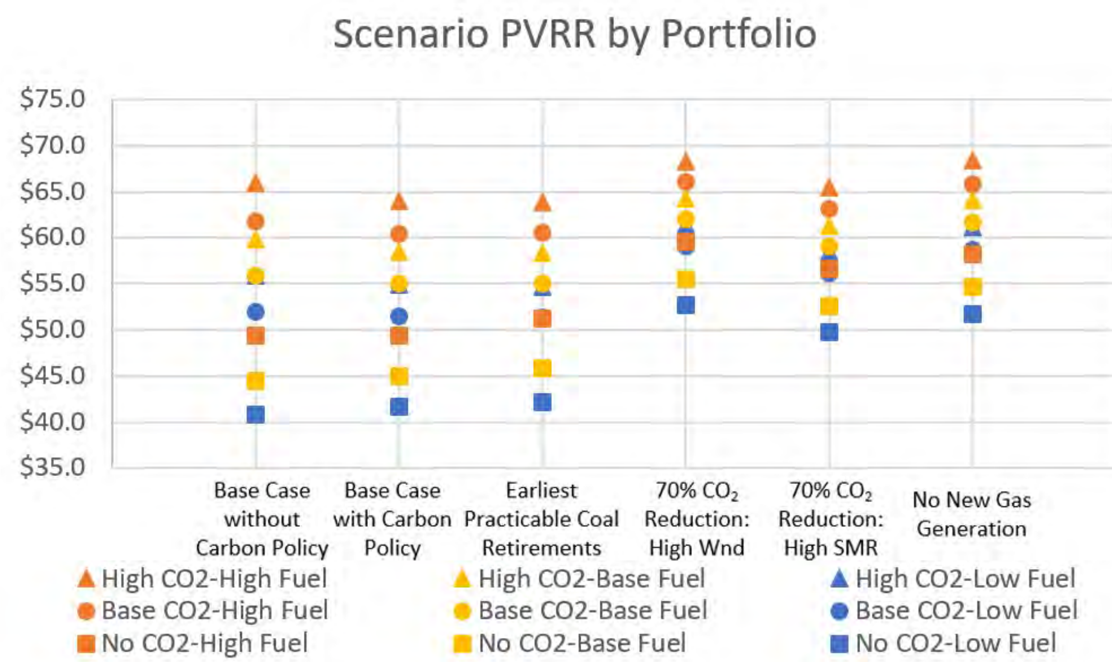
SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, INCLUDING THE EXPLICIT COST OF CARBON, $ BILLIONS

	BASE PLANNING WITHOUT CARBON POLICY	BASE PLANNING WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO_2-High Fuel	$65.9	$64.0	$63.8	$68.3	$65.4	$68.4
High CO_2-Base Fuel	$59.8	$58.5	$58.3	$64.2	$61.3	$64.0
High CO_2-Low Fuel	$55.8	$54.9	$54.7	$61.3	$58.4	$61.1
Base CO_2-High Fuel	$61.8	$60.4	$60.5	$66.0	$63.1	$65.9
Base CO_2-Base Fuel	$55.9	$55.1	$55.0	$61.9	$59.0	$61.6
Base CO_2-Low Fuel	$51.9	$51.4	$51.4	$59.1	$56.2	$58.7
No CO_2-High Fuel	$49.3	$49.4	$51.2	$59.5	$56.6	$58.3
No CO_2-Base Fuel	$44.4	$44.9	$45.8	$55.5	$52.6	$54.6
No CO_2-Low Fuel	$40.8	$41.6	$42.1	$52.7	$49.7	$51.7

Min	$40.8	$41.6	$42.1	$52.7	$49.7	$51.7
Median	$55.8	$54.9	$54.7	$61.3	$58.4	$61.1
Max	$65.9	$64.0	$63.8	$68.3	$65.4	$68.4

FIGURE A-11

SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, INCLUDING THE EXPLICIT COST OF CARBON, $ BILLIONS



In contrast to the previous view, when the costs of carbon are included in the total cost of the plan, the range of PVRRs for each plan is increased. It can be seen that the Base Case without Carbon Policy is again the portfolio that is most sensitive to fuel and carbon policies. While the lowest cost for the Base Case with Carbon Policy and Earliest Practicable Retirements is higher than Base Case without Carbon Policy, the cost ceiling is lower, due to less natural gas on the system, with its associated carbon emissions and cost based on the price of natural gas. Again, the highest reduction plans, the 70% CO_2 Reduction plans and the No New Gas Generation Plan are less sensitive to the fuel and carbon variables, but are overall more expensive plans, though the gap is smaller when the cost of carbon is considered. The results of these PVRRs are dependent on the structural and policy changes that enable carbon reductions, which will be discussed later in this appendix.

AVERAGE RESIDENTIAL MONTHLY BILL IMPACT

The total present value revenue requirement (PVRR) of a plan is a common and useful financial metric in Integrated Resource Planning to measure the cost of the plan over a long period of time. This metric will capture the costs and benefit of accelerating retirements, building new generation and associated transmission, and changing fuel prices and operation costs over time. While this is an important metric, the company is also concerned about the cost to customers on an immediate basis, as providing affordable energy is critical to the company's mission. The analysis of estimating the average residential monthly bill impact attempts to quantify how much a residential customer, using 1,000 kWh of energy a month, can expect to see their bill increase over 2020 costs of service due to the changes identified in this IRP. Below, Table A-17 that shows the resulting increase to a residential customers bill for each of the plans through 2030 and 2035 and the average annual percentage change from 2020 through 2030 and 2035, in the company's base gas price and base carbon price scenario, while excluding the explicit cost of the carbon tax to customer.

TABLE A-17
SCENARIO ANALYSIS AVERAGE MONTHLY RESIDENTIAL BILL IMPACT FOR A HOUSEHOLD USING 1000 KWH

	2030		2035	
	Average Residential Monthly Bill Impact	Average Annual Percentage Change in Residential Bills	Average Residential Monthly Bill Impact	Average Annual Percentage Change in Residential Bills
Base Case without Carbon Policy	$7	0.7%	$23	1.3%
Base Case with Carbon Policy	$8	0.8%	$25	1.5%
Earliest Practicable Coal Retirements	$13	1.3%	$25	1.4%
70% CO_2 Reductions: High Wind	$26	2.3%	$47	2.5%
70% CO_2 Reductions: High SMR	$24	2.2%	$45	2.5%
No New Gas Generation	$12	1.1%	$45	2.4%

Table A-17 shows that the plans with earlier transitions to lower carbon future portfolios and more expensive technologies will see greater cost increase to their bills earlier, while the plans that wait longer to transition, and allow for emerging technologies to decease in price, may lessen and defer some of

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those costs increases. With projected declining cost curves for emerging carbon-free resources the pace of adoption plays a critical role in the ultimate cost to consumers.

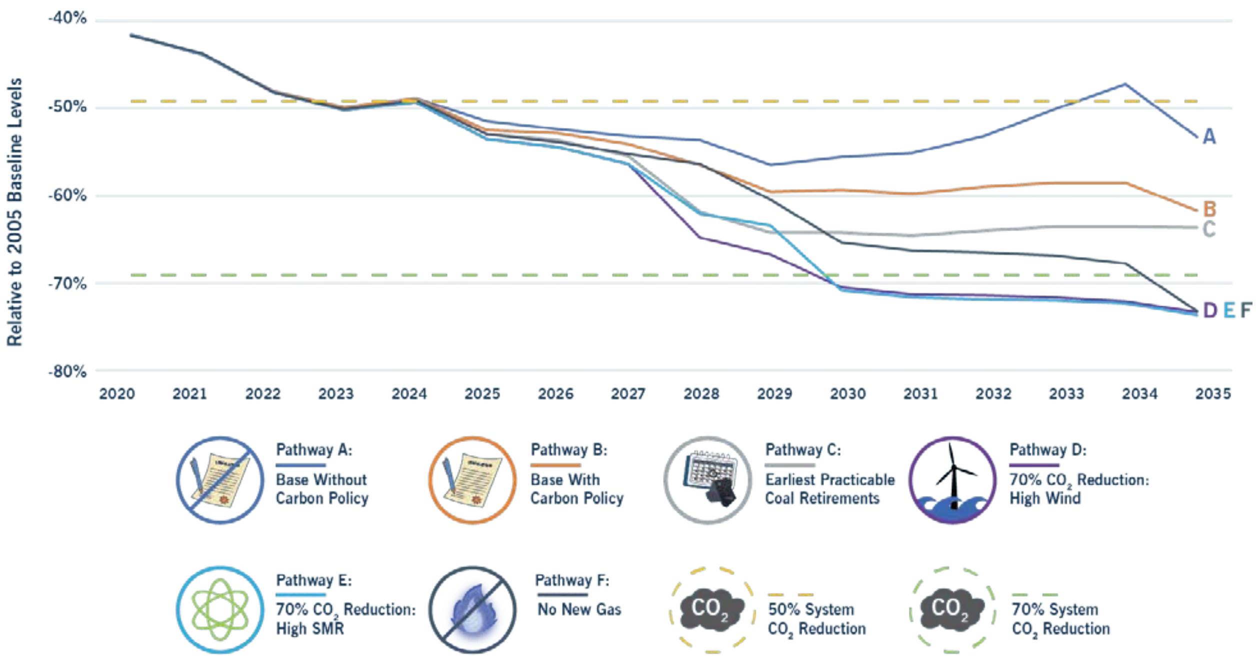
It should be noted that integrating large scale regional energy infrastructure projects, such as bringing offshore wind energy into the Carolinas, would likely require statewide policies. It is likely that the resources and the transmission infrastructure costs to move the energy from the coast to load centers could be spread across all customers in the state rather than those of a single utility. Notwithstanding this possibility, for the purposes of developing the No New Gas Portfolio, all energy, capacity, and associated costs for the results shown are for DEC only, with the recognition that future energy policy could more evenly spread costs across utilities.

PORTFOLIO CARBON REDUCTIONS ANALYSIS

While cost is undoubtably an important factor, one of the most crucial aspects analyzed in this IRP is the trade-off between costs and carbon reductions. The graph below charts the carbon reductions for the combined DEP/DEC system of each of the portfolios in the base fuel and base carbon scenario through the IRP planning window. The resources added throughout time, price on carbon emissions (or lack thereof), and relative price between carbon intense fuels influence these carbon emissions. Additional discussion is presented below.

FIGURE A-12

COMBINED DEP/DEC CARBON REDUCTION BY PORTFOLIO IN BASE FUEL AND BASE CARBON SCENARIO



Through 2024 there are no notable changes in carbon emission reductions between the portfolios. Base Planning without Carbon Policy (Pathway A) continues a trajectory of lowering carbon emissions through 2029, albeit at a slower pace than other pathways, as low cost, lower carbon intense natural gas and increasing penetration of solar offsets higher carbon intense coal generation. As gas price begins to rise in the transition from market fuel prices to fundamental fuel prices, less expensive coal generation becomes more prevalent when a carbon tax is not present. Upon retirement, and replacement of Marshall station in 2035, and replacement with was generation, pathway A sees a reduction in carbon emission again at the end of the planning horizon.

In 2025 the carbon tax comes into effect in pathways B through F, driving the emissions from carbon intense resources down. Increasing additions of solar generation along with the economic pressure of the price on carbon continues to drive carbon reductions in the Base Planning with Carbon Policy (Pathway B). Growing load and rising gas prices minimize the reductions realized by renewables additions in the 2030, resulting in flat CO_2 reduction until 2035, when Marshall is retired.

As coal and other traditional generation retirements take place throughout the mid-2020, the carbon reductions between the pathways begin to diverge, resulting in a range of carbon reduction of 56% to 71% from 2005 baseline. Pathways D and E continue to rise to 70% with the retirement of Belews Creek and Marshall Stations in these scenarios by 2030, where Pathways F flattens out from 2029 through 2035, when Marshall retires in this case. By 2035, Pathways D, E, and F converge again around 73%, when the resource types in these portfolios converge at the end of the IRP horizon with similar penetrations of non-carbon emitting resources.

TABLE A-18

SCENARIO REDUCTIONS IN 2030 FOR EACH PORTFOLIO

	BASE CASE WITHOUT CARBON POLICY	BASE CASE WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO_2-High Fuel	55.9%	58.7%	64.3%	70.5%	70.9%	64.9%
High CO_2-Base Fuel	56.6%	59.4%	64.3%	70.5%	70.8%	65.5%
High CO_2-Low Fuel	56.7%	59.5%	64.2%	70.5%	70.8%	65.6%
Base CO_2-High Fuel	55.7%	58.5%	64.3%	70.5%	70.8%	64.7%
Base CO_2-Base Fuel	56.4%	59.3%	64.2%	70.5%	70.8%	65.4%
Base CO_2-Low Fuel	56.7%	59.5%	64.2%	70.5%	70.8%	65.5%
No CO_2-High Fuel	53.4%	56.5%	64.2%	70.4%	70.8%	63.6%
No CO_2-Base Fuel	55.5%	58.4%	64.1%	70.4%	70.7%	64.6%
No CO_2-Low Fuel	56.0%	58.9%	63.9%	70.2%	70.4%	65.1%

Reduction Range	3.4%	3.0%	0.4%	0.3%	0.5%	2.0%

TABLE A-19

SCENARIO REDUCTIONS IN 2035 FOR EACH PORTFOLIO

	BASE PLANNING WITHOUT CARBON POLICY	BASE PLANNING WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO^2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO_2-High Fuel	56.3%	61.1%	63.6%	73.3%	73.7%	72.6%
High CO_2-Base Fuel	57.2%	61.9%	63.6%	73.3%	73.6%	73.3%
High CO_2-Low Fuel	57.3%	62.0%	63.6%	73.3%	73.6%	73.5%
Base CO_2-High Fuel	54.3%	59.3%	63.6%	73.3%	73.6%	72.1%
Base CO_2-Base Fuel	57.0%	61.7%	63.6%	73.3%	73.6%	73.2%
Base CO_2Low Fuel	57.2%	61.9%	63.6%	73.3%	73.6%	73.5%
No CO_2-High Fuel	49.4%	54.9%	63.6%	73.3%	73.6%	68.1%
No CO_2-Base Fuel	53.2%	58.3%	63.6%	73.3%	73.6%	71.1%
No CO_2-Low Fuel	55.5%	60.4%	63.5%	73.2%	73.5%	72.6%

Reduction Range	7.9%	7.1%	0.2%	0.1%	0.1%	5.4%

Through 2030, the plans with the most sensitivity in carbon emissions are the Base Cases, again due to their continued operations of Coal through the most economic retirement dates, and the additions of natural gas generation throughout the planning horizon. The CO_2 reduction range for the remaining four portfolios is relatively tight, within a 0.5% or less variance for the plans the utilize the earliest practicable retirement dates, and 2% for No New Gas Generation, which does not deploy new natural gas, but relies on the most economic retirement dates of the coal units for deployment of other existing and emerging technologies to replace the retiring capacity.

These observations though 2030 are amplified by 2035. The cases with the most economic coal retirement dates see ranges of carbon reductions from 7.9% in the Base Case without Carbon Policy to 5.4% in the No New Gas Generation plan. Conversely, the plans with the higher costs also deliver consistency in carbon reductions, with emission varying very little with changes to carbon and fuel pricing.

IDENTIFYING OPPORTUNITIES AND RISK MITIGATION

While each of these plans comes with inherent risks, such as exposure to fuel and carbon pricing or early adoption of emerging technologies with cost and operational uncertainties, the utility will have to continue to have constructive conversations with stakeholders, regulators, and customers to identify and mitigate risks that would prevent the company from providing clean, affordable, and reliable energy. Below discusses some of these risks and mitigating measure:

- **Earliest Practicable Coal Retirements** – While the PVRR and Average Residential Monthly Bill Impact results for Earliest Practicable Coal Retirements are relatively comparable to the Base Case with Carbon Policy, this portfolio does present additional potential tradeoffs and dependency on a number of factors. The regulatory approval and feasibility of procuring the replacement generation are foremost on this list. Additionally, some of the earliest practicable coal retirement are predicated on replacement onsite, leveraging existing infrastructure. This assumption avoids transmission upgrades at some of the retiring coal sites to reduce replacement timelines, and results in lower costs of the plan. The most economic retirement dates of the coal units do not assumed replacement at site, and do not benefit from this cost saving. This provides optionality in the replacement process for the cheapest alternatives to be selected but does incur more cost to the plan for the associated transmission upgrades. Project cost risks associated with these accelerated retirements may put stresses on supply chain driving price variations. Furthermore, deploying economically maturing technologies, like batteries, at large scale may increase cost and operational risk, while opting for earlier retirement of coal units by relying on natural gas may impact of deploying lower carbon and ZEFLR technologies in the future or the associated customer impact to do so.

- **Solar Interconnection** – While solar and other intermittent technologies may help lower exposure to variability in the price of fuels and can help reduce carbon emissions, the interconnection and operation of these resources will have to continue to be studied and advanced to allow for affordable and reliable operation of the system.

- **Onshore Wind Integration** – Several studies throughout the industry identify the value of combining variable energy resources like solar and wind with different but potentially complimentary production profiles. Integration of these resources can help continue to lower carbon emissions and spur economic development in the region but overcoming the historic challenges to siting onshore wind in the Carolinas is an issue that requires further study.

- **Offshore Wind Integration –** A largely untapped resource sits just a few miles off the coast of the Carolinas. While there are several hurdles to incorporating this new generation source in the Carolinas systems, such as construction of these wind resources, transmitting that energy to land and then delivering it to the Company's load centers, there is a great opportunity to further reduce carbon emissions and add bulk amounts of zero fuel cost generation to the fleet.

- **ZELFR Development –** While emerging technologies, such as SMRs, were deployed in this IRP, the general development of zero-emitting, load following resources across a range of options will be important to de-risking the transition to a net-zero carbon future.

- **System Operability –** The system operators will have to continue to learn and adapt to new, intermittent and variable energy resources on the system to balance load and generation, utilizing and advancing the flexibility of the existing fleet, while leveraging resources like energy storage and demand side management to continue to provide safe and reliable energy. These transformations envisioned will also rely on significant advancements in the sophistication of the grid control systems needed to manage system operations with these more diverse and distributed new energy resources.

OTHER FINDINGS AND INSIGHTS

- **Gas as a transition fuel -** The No New Gas Generation portfolio in this IRP demonstrates that natural gas remains a cost-effective way to accelerate the remaining coal retirements over the term of this IRP. Many independent studies and articles have supported the continued role of natural gas to balance the intermittency of renewables and continue to decarbonize the system. As shown in the emissions trajectories graph, the No New Gas portfolio emits more CO_2, over the fifteen-year period through 2035 and is significantly more costly than the 70% Carbon Reduction by 2030 portfolios (D and E) that include natural gas as a replacement resource. Eliminating natural gas generation as an option is likely to have the unintended effect of delaying coal retirements and increasing CO_2 in the interim, as more coal generation is required to serve load without new efficient natural gas resources as a transition technology.

- **Gas transportation services -** On July 5th, 2020 Dominion Energy and Duke Energy announced the cancellation of Atlantic Coast Pipeline (ACP) citing anticipated delays and increasing cost uncertainty due to on-going permitting and legal challenges. DEP and DEC still need additional firm interstate transportation service to support existing and future gas generation in the Carolinas despite the cancellation of the project. The 2020 IRP assumes incremental firm transportation service volumes as contemplated in the ACP project are needed from alternate pipeline providers to cost effectively support both existing natural gas generation fleet and future combined cycle natural gas generation growth. Additionally, incremental firm interstate transportation service is assumed to be procured for any new combined cycle natural gas resource selected in the generation portfolios in this IRP along with firm transportation service cost estimates. The estimated firm transportation service costs were considered in the resource selection process and are included in the financial results presented. Consistent with past IRPs, the planning process does not assume incremental interstate capacity is procured for additional simple cycle CTs given their low capacity factors. Rather, CTs are planned as dual fuel units that are ultimately connected to Transco Zone 5 and will rely on delivered Zone 5 gas supply or if needed ultra-low sulfur fuel oil during winter periods where natural gas has limited availability, the pipeline has additional constraints, or gas is higher priced than the cost to operate on fuel oil. Additional discussion on ACP and Fuel Supply can be found in Appendix F.

- **Discussion on Levelized Cost of Energy (LCOE) -** A common source of confusion over the economics of replacement generation for coal retirements are "Levelized Cost of Energy" reports that attempt to compare all-in costs divided by total energy production on a $/MWh basis. While this can be a useful high-level economic screening tool, it does not speak to the capacity value of a resource, nor does it recognize time value differences in energy production, which can vary dramatically as is the case with high levels of renewable resources. Simple LCOE analysis ignores the reality that it can take several times the amount of installed capacity of certain intermittent resources to produce the same reliability of dispatchable resources, even if those resources are paired with energy storage. This multiplier effect can create additional hurdles related to the permitting and interconnection of a significantly larger amount of resources (on a nameplate MW basis), which naturally has cost implications. To illustrate the multiplier effect, the Company has developed a Portfolio Screening Tool which will be released to the public shortly after the IRP filing.

- **Emerging technologies decommissioning costs -** Industry research is beginning to address decommissioning challenges and costs and potential materials recycling opportunities for these new and emerging technologies. While there are allowances for some costs at end of life, more information will be needed to forecast these costs and the resource selections are being made.

- **A balanced approach to aggressive carbon reduction goals –** The company has stated that a balanced portfolio of resources with varying attributes to produce carbon-free energy, respond to variations in load and generation, shift energy, and reduce overall energy and demand is an important aspect for the Company to consider in resource planning. A combination and blend of these resources in the portfolio may help reduce reliance on the development or price declines of a single resource type and provide the system with the balance of attribute to reliably and more affordably meet the customers' energy needs.

VALUE OF JOINT PLANNING

To demonstrate the value of sharing capacity with DEP, a Joint Planning Case was developed to examine the impact of joint capacity planning on the resource plans. The impacts were determined by comparing how the combined Base Case with Carbon Policy plans for DEC and DEP would change if a 17% minimum winter planning reserve margin was applied at the combined system level, rather than the individual company level.

An evaluation was performed comparing the Base Case with Carbon Policy plans for DEC and DEP to a combined Joint Planning Case in which existing and future capacity resources could be shared between DEC and DEP to meet the 17% minimum winter planning reserve margin. Table A-20 shows the base expansion plans (Base Case with Carbon Policy for both DEC and DEP) through 2035, if separately planned, compared to the Joint Planning Case. The sum of the two combined resource requirements is then compared to the amount of resources needed if DEC and DEP could jointly plan for capacity. Planned projects and the economic selection of renewables and batteries were not reoptimized for this sensitivity. Delaying and accelerating of gas units was used to preserve the joint system's 17% reserve margin. Years where the Joint Planning Case differ from the individual Utility cases are highlighted.

TABLE A-20

COMPARISON OF BASE CASE WITH CARBON POLICY OF INDIVIDUAL UTILITY PLANNING TO JOINT PLANNING SENSITIVITY

	INDIVIDUAL UTILITY PLANNING					
	DEC		DEP		COMBINED SYSTEM	
	CC	CT	CC	CT	CC	CT
2021	0	0	0	0	0	0
2022	0	0	0	0	0	0
2023	0	0	0	0	0	0
2024	0	0	0	0	0	0
2025	0	0	0	0	0	0
2026	0	0	0	457	0	457
2027	0	0	0	914	0	914
2028	0	0	1,224	914	1,224	914
2029	0	0	2,448	1,828	2,448	1,828
2030	0	457	2,448	1,828	2,448	2,285
2031	0	914	2,448	1,828	2,448	2,742
2032	0	914	2,448	1,828	2,448	2,742
2033	0	914	2,448	1,828	2,448	2,742
2034	0	914	2,448	1,828	2,448	2,742
2035	1,224	1,828	2,448	1,828	3,672	3,656

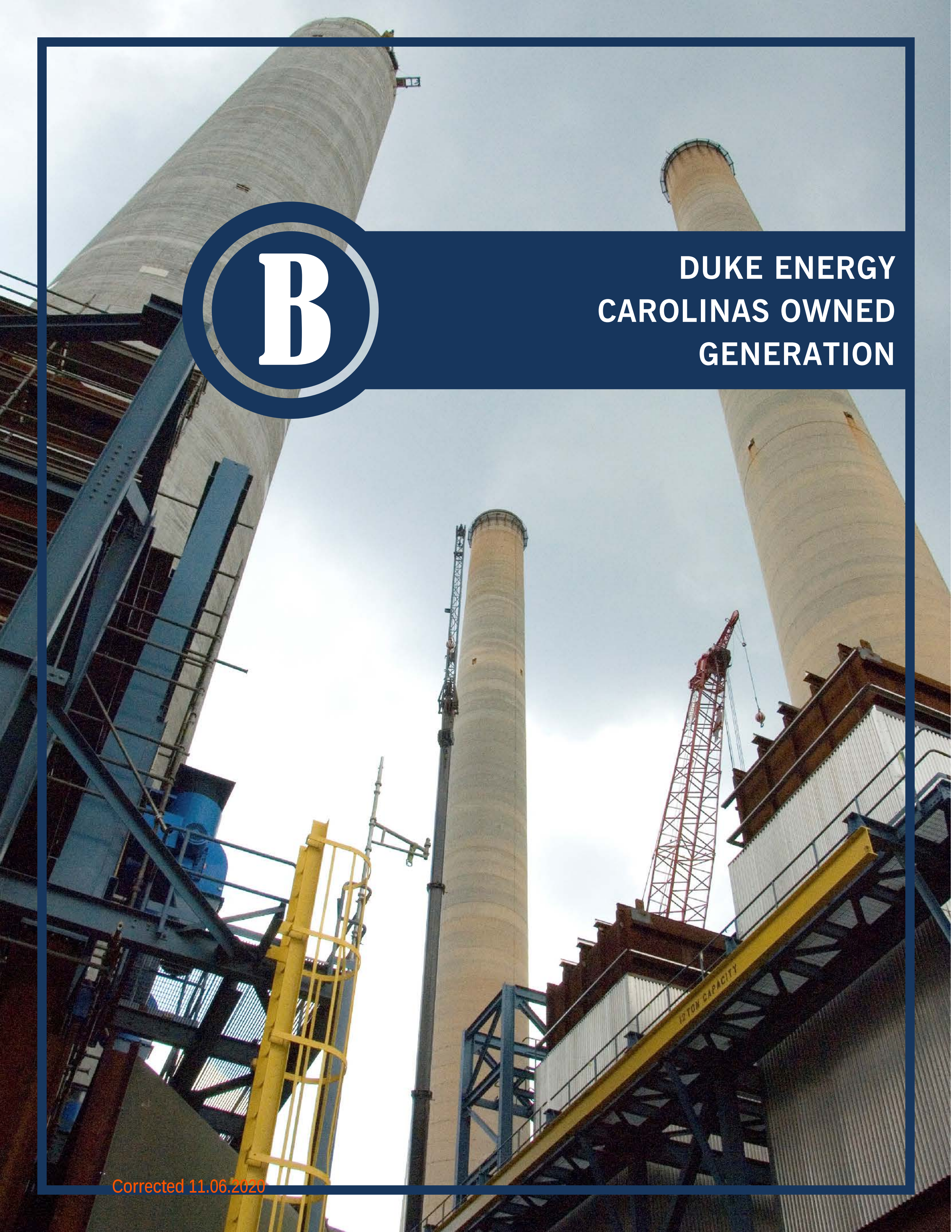
	JOINT PLANNING	
	COMBINED SYSTEM	
	CC	CT
2021	0	0
2022	0	0
2023	0	0
2024	0	0
2025	0	0
2026	0	457
2027	0	457
2028	1,224	914
2029	2,448	1,828
2030	2,448	1,828
2031	2,448	2,285
2032	2,448	2,285
2033	2,448	2,742
2034	2,448	2,742
2035	3,672	3,199

A comparison of the DEC and DEP Combined Base Case resource requirements to the Joint Planning Scenario requirements illustrates the ability to defer a CT resource starting in 2027. Consequently, the Joint Planning Case also results in a lower overall reserve margin. This is confirmed by a review of the reserve margins for the Combined Base Case as compared to the Joint Planning Case, which averaged 18.2% and 18.3%, respectively, from the first need in DEP in 2026 over the remaining IRP planning horizon. The ability to share resources and achieve incrementally lower reserve margins from year to year in the Joint Planning Case illustrates the efficiency and economic potential for DEC and DEP when planning for capacity jointly. Finally, as discussed in the Company's updated Resource Adequacy Study the benefits of a joint system can have beneficial results and could potentially lead to even a slightly lower reserve margin than the 17% examined in the Joint Planning Case.

Corrected 11.06.2020

B

DUKE ENERGY CAROLINAS OWNED GENERATION



Corrected 11.06.2020

APPENDIX B: DUKE ENERGY CAROLINAS OWNED GENERATION

Duke Energy Carolinas' generation portfolio includes a balanced mix of resources with different operating and fuel characteristics. This mix is designed to provide energy at the lowest reasonable cost to meet the Company's obligation to serve its customers. Duke Energy Carolinas-owned generation, as well as purchased power, is evaluated on a real-time basis in order to select and dispatch the lowest-cost resources to meet system load requirements.

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

EXISTING GENERATING UNITS AND RATINGS [A, B, C, D, E, F, G]

ALL GENERATING UNIT RATINGS ARE AS OF JANUARY 1, 2020

COAL									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Allen	1	167	162	Belmont, N.C.	Coal	Peaking	62	4	N/A
Allen	2	167	162	Belmont, N.C.	Coal	Peaking	62	2	N/A
Allen	3	270	258	Belmont, N.C.	Coal	Peaking	60	2	N/A
Allen	4	267	257	Belmont, N.C.	Coal	Intermediate	59	2	N/A
Allen	5	259	259	Belmont, N.C.	Coal	Peaking	58	4	N/A
Belews Creek	1	1110	1110	Belews Creek, N.C.	Coal	Base	45	19	N/A
Belews Creek	2	1110	1110	Belews Creek, N.C.	Coal	Base	44	19	N/A
Cliffside	5	546	544	Cliffside, N.C.	Coal	Peaking	47	6	N/A
Cliffside	6	849	844	Cliffside, N.C.	Coal	Intermediate	7	29	N/A
Marshall	1	380	370	Terrell, N.C.	Coal	Intermediate	54	15	N/A
Marshall	2	380	370	Terrell, N.C.	Coal	Intermediate	53	15	N/A
Marshall	3	658	658	Terrell, N.C.	Coal	Base	50	15	N/A
Marshall	4	660	660	Terrell, N.C.	Coal	Base	49	15	N/A
Total Coal		6,823	6,764						

Corrected 11.06.2020

COMBUSTION TURBINES									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Lee	7C	48	42	Pelzer, S.C.	Natural Gas/Oil-Fired	Peaking	12	28	N/A
Lee	8C	48	42	Pelzer, S.C.	Natural Gas/Oil-Fired	Peaking	12	28	N/A
Lincoln	1	98	76	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	2	99	76	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	3	99	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	4	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	5	97	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	6	97	73	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	7	98	76	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	8	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	9	97	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	10	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	11	98	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	12	98	75	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	24	16	N/A
Lincoln	13	98	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	23	16	N/A
Lincoln	14	97	74	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	23	16	N/A
Lincoln	15	98	73	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	23	16	N/A
Lincoln	16	97	73	Stanley, N.C.	Natural Gas/Oil-Fired	Peaking	23	16	N/A

Corrected 11.06.2020

COMBUSTION TURBINES (CONT.)									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Mill Creek	1	94	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking	17	24	N/A
Mill Creek	2	94	70	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking	17	24	N/A
Mill Creek	3	95	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking	17	24	N/A
Mill Creek	4	94	70	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking	17	24	N/A
Mill Creek	5	94	69	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking	16	24	N/A
Mill Creek	6	92	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking	16	24	N/A
Mill Creek	7	95	70	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking	16	24	N/A
Mill Creek	8	93	71	Blacksburg, S.C.	Natural Gas/Oil-Fired	Peaking	16	24	N/A
Rockingham	1	179	165	Reidsville, N.C.	Natural Gas/Oil-Fired	Peaking	19	21	N/A
Rockingham	2	179	165	Reidsville, N.C.	Natural Gas/Oil-Fired	Peaking	19	21	N/A
Rockingham	3	179	165	Reidsville, N.C.	Natural Gas/Oil-Fired	Peaking	19	21	N/A
Rockingham	4	179	165	Reidsville, N.C.	Natural Gas/Oil-Fired	Peaking	19	21	N/A
Rockingham	5	179	165	Reidsville, N.C.	Natural Gas/Oil-Fired	Peaking	19	21	N/A
Total NC		2,460	2,018						
Total SC		847	647						
Total CT		3,307	2,665						

Corrected 11.06.2020

NATURAL GAS FIRED BOILER									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Lee	3	173	170	Pelzer, S.C.	Natural Gas	Peaking	61	11	N/A
Total Nat. Gas		173	170						

Corrected 11.06.2020

COMBINED CYCLE									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Buck	CT11	206	178	Salisbury, N.C.	Natural Gas	Base	8	32	N/A
Buck	CT12	206	178	Salisbury, N.C.	Natural Gas	Base	8	32	N/A
Buck	ST10	304	312	Salisbury, N.C.	Natural Gas	Base	8	32	N/A
Buck CTCC		716	668						
Dan River	CT8	199	171	Eden, N.C.	Natural Gas	Base	7	33	N/A
Dan River	CT9	199	171	Eden, N.C.	Natural Gas	Base	7	33	N/A
Dan River	ST7	320	320	Eden, N.C.	Natural Gas	Base	7	33	N/A
Dan River CTCC		718	662						
WS Lee	CT11	240	237	Pelzer, S.C.	Natural Gas	Base	1	N/A	N/A
WS Lee	CT12	239	236	Pelzer, S.C.	Natural Gas	Base	1	N/A	N/A
WS Lee	ST10	313	313	Pelzer, S.C.	Natural Gas	Base	1	N/A	N/A
WS Lee CTCC		792	786						
Total CTCC		2,226	2,116						

COMBINED HEAT & POWER									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Clemson CHP	GT01	15.7	12.8	Pickens, S.C.	Natural Gas	Base	1 month	N/A	N/A
Total CHP		15.7	12.8						

Corrected 11.06.2020

PUMPED STORAGE									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Jocassee	1	195	195	Salem, S.C.	Pumped Storage	Peaking	46	27	2046
Jocassee	2	195	195	Salem, S.C.	Pumped Storage	Peaking	46	27	2046
Jocassee	3	195	195	Salem, S.C.	Pumped Storage	Peaking	44	27	2046
Jocassee	4	195	195	Salem, S.C.	Pumped Storage	Peaking	44	27	2046
Bad Creek	1	340	340	Salem, S.C.	Pumped Storage	Peaking	28	39	2027
Bad Creek	2	340	340	Salem, S.C.	Pumped Storage	Peaking	28	39	2027
Bad Creek	3	340	340	Salem, S.C.	Pumped Storage	Peaking	28	39	2027
Bad Creek	4	340	340	Salem, S.C.	Pumped Storage	Peaking	28	39	2027
Total Pump. Storage		2,140	2,140						

HYDRO									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
99 Islands	1	4.2	4.2	Blacksburg, S.C.	Hydro	Peaking	109	N/A	2036
99 Islands	2	3.4	3.4	Blacksburg, S.C.	Hydro	Peaking	109	N/A	2036
99 Islands	3	4.2	4.2	Blacksburg, S.C.	Hydro	Peaking	109	N/A	2036
99 Islands	4	3.4	3.4	Blacksburg, S.C.	Hydro	Peaking	109	N/A	2036
Bear Creek	1	9.5	9.5	Tuckasegee, N.C.	Hydro	Peaking	65	N/A	2041
Bridgewater	1	15	15	Morganton, N.C.	Hydro	Peaking	100	N/A	2055
Bridgewater	2	15	15	Morganton, N.C.	Hydro	Peaking	100	N/A	2055
Bridgewater	3	1.5	1.5	Morganton, N.C.	Hydro	Peaking	100	N/A	2055
Cedar Cliff	1	6.4	6.4	Tuckasegee, N.C.	Hydro	Peaking	67	N/A	2041
Cedar Cliff	2	0.4	0.4	Tuckasegee, N.C.	Hydro	Peaking	67	N/A	2041
Cedar Creek	1	15	15	Great Falls, S.C.	Hydro	Peaking	93	N/A	2055
Cedar Creek	2	15	15	Great Falls, S.C.	Hydro	Peaking	93	N/A	2055
Cedar Creek	3	15	15	Great Falls, S.C.	Hydro	Peaking	93	N/A	2055
Cowans Ford	1	81	81	Stanley, N.C.	Hydro	Peaking	56	N/A	2055
Cowans Ford	2	81	81	Stanley, N.C.	Hydro	Peaking	56	N/A	2055
Cowans Ford	3	81	81	Stanley, N.C.	Hydro	Peaking	56	N/A	2055
Cowans Ford	4	81	81	Stanley, N.C.	Hydro	Peaking	52	N/A	2055

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HYDRO (CONT.)									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Dearborn	1	14	14	Great Falls, S.C.	Hydro	Peaking	96	N/A	2055
Dearborn	2	14	14	Great Falls, S.C.	Hydro	Peaking	96	N/A	2055
Dearborn	3	14	14	Great Falls, S.C.	Hydro	Peaking	96	N/A	2055
Fishing Creek	1	11	11	Great Falls, S.C.	Hydro	Peaking	103	N/A	2055
Fishing Creek	2	10	10	Great Falls, S.C.	Hydro	Peaking	103	N/A	2055
Fishing Creek	3	10	10	Great Falls, S.C.	Hydro	Peaking	103	N/A	2055
Fishing Creek	4	11	11	Great Falls, S.C.	Hydro	Peaking	103	N/A	2055
Fishing Creek	5	8	8	Great Falls, S.C.	Hydro	Peaking	103	N/A	2055
Great Falls	1	3	3	Great Falls, S.C.	Hydro	Peaking	112	N/A	2055
Great Falls	2	3	3	Great Falls, S.C.	Hydro	Peaking	112	N/A	2055
Great Falls	5	3	3	Great Falls, S.C.	Hydro	Peaking	112	N/A	2055
Great Falls	6	3	3	Great Falls, S.C.	Hydro	Peaking	112	N/A	2055
Keowee	1	76	76	Seneca, S.C.	Hydro	Peaking	48	N/A	2046
Keowee	2	76	76	Seneca, S.C.	Hydro	Peaking	48	N/A	2046
Lookout Shoals	1	9.0	9.0	Statesville, N.C.	Hydro	Peaking	104	N/A	2055
Lookout Shoals	2	9.0	9.0	Statesville, N.C.	Hydro	Peaking	104	N/A	2055
Lookout Shoals	3	9.0	9.0	Statesville, N.C.	Hydro	Peaking	104	N/A	2055
Mountain Island	1	14	14	Mount Holly, N.C.	Hydro	Peaking	96	N/A	2055
Mountain Island	2	14	14	Mount Holly, N.C.	Hydro	Peaking	96	N/A	2055
Mountain Island	3	17	17	Mount Holly, N.C.	Hydro	Peaking	96	N/A	2055
Mountain Island	4	17	17	Mount Holly, N.C.	Hydro	Peaking	96	N/A	2055
Nantahala	1	50	50	Topton, N.C.	Hydro	Peaking	77	N/A	2042

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HYDRO (CONT.)									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Oxford	1	20	20	Conover, N.C.	Hydro	Peaking	91	N/A	2055
Oxford	2	20	20	Conover, N.C.	Hydro	Peaking	91	N/A	2055
Queens Creek	1	1.4	1.4	Topton, N.C.	Hydro	Peaking	70	N/A	2032
Rhodhiss	1	9.5	9.5	Rhodhiss, N.C.	Hydro	Peaking	94	N/A	2055
Rhodhiss	2	11.5	11.5	Rhodhiss, N.C.	Hydro	Peaking	94	N/A	2055
Rhodhiss	3	12.4	12.4	Rhodhiss, N.C.	Hydro	Peaking	94	N/A	2055
Tennessee Creek	1	9.8	9.8	Tuckasegee, N.C.	Hydro	Peaking	64	N/A	2041
Thorpe	1	19.7	19.7	Tuckasegee, N.C.	Hydro	Peaking	78	N/A	2041
Tuckasegee	1	2.5	2.5	Tuckasegee, N.C.	Hydro	Peaking	69	N/A	2041
Wateree	1	17	17	Ridgeway, S.C.	Hydro	Peaking	100	N/A	2055
Wateree	2	17	17	Ridgeway, S.C.	Hydro	Peaking	100	N/A	2055
Wateree	3	17	17	Ridgeway, S.C.	Hydro	Peaking	100	N/A	2055
Wateree	4	17	17	Ridgeway, S.C.	Hydro	Peaking	100	N/A	2055
Wateree	5	17	17	Ridgeway, S.C.	Hydro	Peaking	100	N/A	2055
Wylie	1	18	18	Fort Mill, S.C.	Hydro	Peaking	94	N/A	2055
Wylie	2	18	18	Fort Mill, S.C.	Hydro	Peaking	94	N/A	2055
Wylie	3	18	18	Fort Mill, S.C.	Hydro	Peaking	94	N/A	2055
Wylie	4	6	6	Fort Mill, S.C.	Hydro	Peaking	94	N/A	2055
Total NC		617.6	617.6						
Total SC		461.2	461.2						
Total Hydro		1,078.8	1,078.8						

SOLAR									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
NC Solar		76	76	N.C.	Solar	Intermediate	Various	N/A	N/A
Total Solar		76	76						

NUCLEAR									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
McGuire	1	1199.0	1158.0	Huntersville, N.C.	Nuclear	Base	38	44	2041
McGuire	2	1187.2	1157.6	Huntersville, N.C.	Nuclear	Base	35	44	2043
Catawba	1	1198.7	1160.1	York, S.C.	Nuclear	Base	34	44	2043
Catawba	2	1179.8	1150.1	York, S.C.	Nuclear	Base	34	44	2043
Oconee	1	865	847	Seneca, S.C.	Nuclear	Base	46	35	2033
Oconee	2	872	848	Seneca, S.C.	Nuclear	Base	45	35	2033
Oconee	3	881	859	Seneca, S.C.	Nuclear	Base	45	35	2034
Total NC		2,386.2	2,315.6						
Total SC		4,996.5	4,864.2						
Total Nuclear		7,382.7	7,179.8						

TOTAL GENERATION CAPABILITY		
	WINTER CAPACITY (MW)	SUMMER CAPACITY (MW)
TOTAL DEC SYSTEM - N.C.	13,796.8	13,121.2
TOTAL DEC SYSTEM – S.C.	9,425.4	9,081.2
TOTAL DEC SYSTEM	23,222.2	22,202.4

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

NOTE b: Cliffside also called the Rogers Energy Center.

NOTE c: Catawba Units 1 and 2 capacity reflects 100% of the station's capability.

NOTE d: WS Lee Combined Cycle (CC) Units CT11, CT12 and ST10 reflects 100% of the CC's capability and does not factor in the 100 MW of capacity owned by NCEMC. The DEC – NCEMC Joint-Owner contract includes an energy buyback provision for DEC of the capacity owned by NCEMC in the WS Lee CC facility.

NOTE e: Solar capacity ratings reflect nameplate capacity.

NOTE f: Lee Unit 3 summer capacity rating reflects nameplace value.

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

NOTE h: The Catawba units' multiple owners and their effective ownership percentages are:

CATAWBA OWNER	PERCENT OF OWNERSHIP
Duke Energy Carolinas	19.246%
North Carolina Electric Membership Corporation (NCEMC)	30.754%
NCMPA#1	37.5%
PMPA	12.5%

PLANNED ADDITIONS / UPRATES			
UNIT	DATE	WINTER MW	SUMMER MW
Bad Creek 1	Sept 2021	65.0	65.0
Bad Creek 2	Sept 2020	65.0	65.0
Bad Creek 3	Sept 2022	65.0	65.0
Bad Creek 4	Sept 2023	65.0	65.0
Oconee 1	Jan 2023	15.0	15.0
Oconee 2	Jan 2022	15.0	15.0
Oconee 3	May 2022	15.0	15.0
Catawba 1	May 2020	6.0	6.0
Catawba 2	Apr 2021	6	6
Clemson CHP	Nov 2020	15.0	15.0

NOTE: This capacity not reflected in unit ratings in above tables.

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RETIREMENTS				
UNIT AND PLANT NAME	LOCATION	CAPACITY (MW) SUMMER	FUEL TYPE	RETIREMENT DATE
Buck 3[a]	Salisbury, N.C.	75	Coal	05/15/11
Buck 4[a]	Salisbury, N.C.	38	Coal	05/15/11
Cliffside 1[a]	Cliffside, N.C.	38	Coal	10/1/11
Cliffside 2[a]	Cliffside, N.C.	38	Coal	10/1/11
Cliffside 3[a]	Cliffside, N.C.	61	Coal	10/1/11
Cliffside 4[a]	Cliffside, N.C.	61	Coal	10/1/11
Dan River 1[a]	Eden, N.C.	67	Coal	04/1/12
Dan River 2[a]	Eden, N.C.	67	Coal	04/1/12
Dan River 3[a]	Eden, N.C.	142	Coal	04/1/12
Buzzard Roost 6C[b]	Chappels, S.C.	22	Combustion Turbine	10/1/12
Buzzard Roost 7C[b]	Chappels, S.C.	22	Combustion Turbine	10/1/12
Buzzard Roost 8C	Chappels, S.C.	22	Combustion Turbine	10/1/12
Buzzard Roost 9C[b]	Chappels, S.C.	22	Combustion Turbine	10/1/12
Buzzard Roost 10C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 11C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 12C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 13C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 14C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Buzzard Roost 15C[b]	Chappels, S.C.	18	Combustion Turbine	10/1/12
Riverbend 8C[b]	Mt. Holly, N.C.	0	Combustion Turbine	10/1/12
Riverbend 9C[b]	Mt. Holly, N.C.	22	Combustion Turbine	10/1/12
Riverbend 10C[b]	Mt. Holly, N.C.	22	Combustion Turbine	10/1/12
Riverbend 11C[b]	Mt. Holly, N.C.	20	Combustion Turbine	10/1/12

RETIREMENTS (CONT.)				
Buck 7C [b]	Spencer, N.C.	25	Combustion Turbine	10/1/12
Buck 8C [b]	Spencer, N.C.	25	Combustion Turbine	10/1/12
Buck 9C [b]	Spencer, N.C.	12	Combustion Turbine	10/1/12
Dan River 4C [b]	Eden, N.C.	0	Combustion Turbine	10/1/12
Dan River 5C [b]	Eden, N.C.	24	Combustion Turbine	10/1/12
Dan River 6C [b]	Eden, N.C.	24	Combustion Turbine	10/1/12
Riverbend 4 [a]	Mt. Holly, N.C.	94	Coal	04/1/13
Riverbend 5 [a]	Mt. Holly, N.C.	94	Coal	04/1/13
Riverbend 6 [c]	Mt. Holly, N.C.	133	Coal	04/1/13
Riverbend 7 [c]	Mt. Holly, N.C.	133	Coal	04/1/13
Buck 5 [c]	Spencer, N.C.	128	Coal	04/1/13
Buck 6 [c]	Spencer, N.C.	128	Coal	04/1/13
Lee 1 [d]	Pelzer, S.C.	100	Coal	11/6/14
Lee 2 [d]	Pelzer, S.C.	100	Coal	11/6/14
Lee 3 [e]	Pelzer, S.C.	170	Coal	05/12/15*
Great Falls 3	Great Falls, S.C.	0	Hydro	05/31/18
Great Falls 4	Great Falls, S.C.	0	Hydro	05/31/18
Great Falls 7	Great Falls, S.C.	0	Hydro	05/31/18
Great Falls 8	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 1	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 2	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 3	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 4	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 5	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 6	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 7	Great Falls, S.C.	0	Hydro	05/31/18
Rocky Creek 8	Great Falls, S.C.	0	Hydro	05/31/18
Ninety-Nine Islands 5	Blacksburg, S.C.	0	Hydro	12/31/18
Ninety-Nine Islands 6	Blacksburg, S.C.	0	Hydro	12/31/18
Bryson City 1 [f]	Whittier, N.C.	.5	Hydro	08/16/2019
Bryson City 2 [f]	Whittier, N.C.	.4	Hydro	08/16/2019
Franklin 1 [f]	Franklin, N.C.	.5	Hydro	08/16/2019
Franklin 2 [f]	Franklin, N.C.	.5	Hydro	08/16/2019
Gaston Shoals 3 [f]	Blacksburg, S.C.	0	Hydro	08/16/2019
Gaston Shoals 4 [f]	Blacksburg, S.C.	0	Hydro	08/16/2019

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RETIREMENTS (CONT.)				
Gaston Shoals 5 [f]	Blacksburg, S.C.	2	Hydro	08/16/2019
Gaston Shoals 6 [f]	Blacksburg, S.C.	2.5	Hydro	08/16/2019
Mission 1 [f]	Murphy, N.C.	.6	Hydro	08/16/2019
Mission 2 [f]	Murphy, N.C.	.6	Hydro	08/16/2019
Mission 3 [f]	Murphy, N.C.	.6	Hydro	08/16/2019
Tuxedo 1 [f]	Flat Rock, N.C.	3.2	Hydro	08/16/2019
Tuxedo 2 [f]	Flat Rock, N.C.	3.2	Hydro	08/16/2019
	Total	2,051.6 MW		

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

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

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

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

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

NOTE f: Sold to Northbrook Energy 8/16/2019.

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PLANNING ASSUMPTIONS – UNIT RETIREMENTS [a,b,c]					
Unit & Plant Name	Location	Winter Capacity (MW)	Summer Capacity (MW)	Fuel Type	Expected Retirement
Allen 1	Belmont, NC	167	162	Coal	12/2023
Allen 2	Belmont, NC	167	162	Coal	12/2021
Allen 3	Belmont, NC	270	261	Coal	12/2021
Allen 4	Belmont, NC	282	276	Coal	12/2021
Allen 5	Belmont, NC	275	266	Coal	12/2023
Belews Creek 1	Belews Creek, NC	1,110	1,110	Coal	12/2038
Belews Creek 2	Belews Creek, NC	1,110	1,110	Coal	12/2038
Cliffside 5	Cliffside, NC	546	544	Coal	12/2025
Cliffside 6	Cliffside, NC	844	844	Coal	12/2048
Marshall 1	Terrell, NC	380	370	Coal	12/2034
Marshall 2	Terrell, NC	380	370	Coal	12/2034
Marshall 3	Terrell, NC	658	658	Coal	12/2034
Marshall 4	Terrell, NC	660	660	Coal	12/2034
Lee 3	Pelzer, SC	173	160	NG	12/2030
Total		7,022	6,953		

NOTE a: Retirement assumptions are for planning purposes only; retirement dates based on the LCR in the 2020 Integrated Resource Plan.

NOTE b: Coal unit retirement dates based on most economic retirement dates as determined in the Coal Retirement Study (see Chapter 11).

NOTE c: For planning purposes, the 2020 IRP Base Case assumes subsequent license renewal for existing nuclear facilities beginning at end of current operating licenses. Total planning retirements exclude nuclear capacities.

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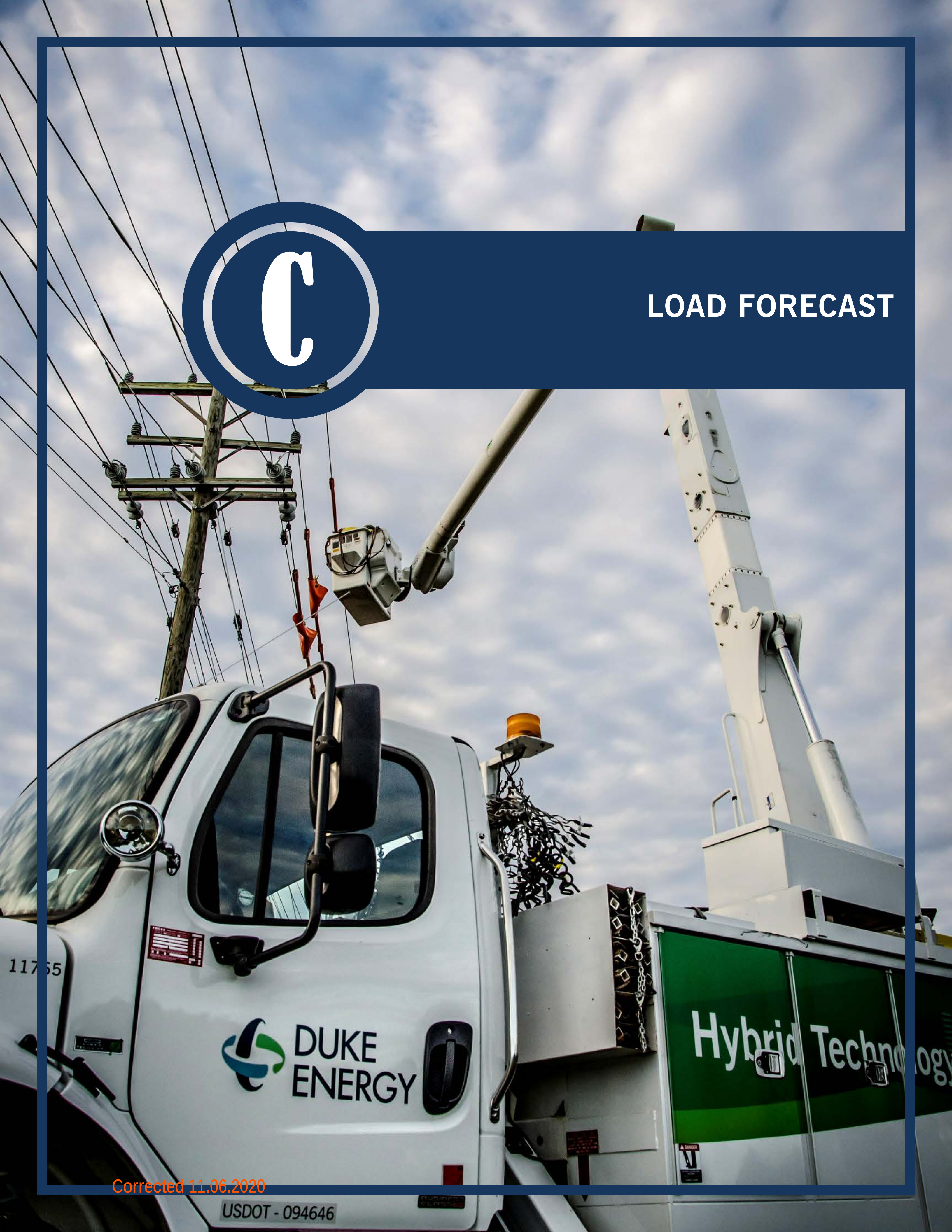
OPERATING LICENSE RENEWAL

Operating License Renewal - Nuclear				
Plant and Unit Name	Location	Original Operating License Expiration	Date of Approval	Extended Operating License Expiration
Catawba Unit 1	York, SC	12/6/2024	12/5/2003	12/5/2043
Catawba Unit 2	York, SC	2/24/2026	12/5/2003	12/5/2043
McGuire Unit 1	Huntersville, NC	6/12/2021	12/5/2003	6/12/2041
McGuire Unit 2	Huntersville, NC	3/3/2023	12/5/2003	3/3/2043
Oconee Unit 1	Seneca, SC	2/6/2013	5/23/2000	2/6/2033
Oconee Unit 2	Seneca, SC	10/6/2013	5/23/2000	10/6/2033
Oconee Unit 3	Seneca, SC	7/19/2014	5/23/2000	7/19/2034



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LOAD FORECAST

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APPENDIX C: ELECTRIC LOAD FORECAST

METHODOLOGY

The Duke Energy Carolinas' Spring 2020 forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2021 – 2035 and represents the needs of the following customer classes:

DEC LOAD FORECAST CUSTOMER CLASSES

Energy projections are developed with econometric models using key economic factors such as income, electricity prices, industrial production indices, along with weather, appliance efficiency trends, rooftop solar trends, and electric vehicle trends. Population is also used in the residential customer model.

The economic projections used in the Spring 2020 Forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of North and South Carolina. Moody's forecasts consist of economic and demographic projections, which are used in the energy and demand models.

The Spring 2020 forecast was developed using Moody's economic inputs as of January 2020. Therefore; the disruptions experienced due to COVID-19 are not incorporated in this forecast. We are continuing to monitor the impacts seen to both energies and peaks, and currently think that the longer-term impacts will be minimal. We will however continue to evaluate the impacts, and update future forecasts for expected impacts.

The Retail forecast consists of the three major classes: Residential, Commercial and Industrial. The Residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electricity prices and appliance efficiencies.

The usage per customer forecast was derived using a Statistical Adjusted End-Use Model (SAE). This is a regression-based framework that uses projected appliance saturation and efficiency trends developed by Itron using Energy Information Administration (EIA) data. It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models. The outlook for usage per customer is essentially flat through much of the forecast horizon, so most of the growth is primarily due to customer increases. The average annual growth rate for the residential class in the Spring 2020 forecast, including the impacts of Utility Energy Efficiency programs (UEE), rooftop solar and electric vehicles from 2021 – 2035 is 1.5%.

The Commercial forecast also uses an SAE model to reflect naturally occurring as well as government mandated efficiency changes. The three largest sectors in the commercial class are offices, education and retail. Commercial energy sales are expected to grow 0.5% per year over the forecast horizon.

The Industrial class is forecasted by a standard econometric model, with drivers such as total manufacturing output and the price of electricity. Overall, Industrial sales are expected to decline 0.2% per year over the forecast horizon.

Weather impacts are incorporated into the models by using Heating Degree Days with a base temperature of 59 and Cooling Degree Days with a base temperature of 65. The forecast of degree days is based on a 30-year average, which is updated every year.

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

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

FORECAST ENHANCEMENTS

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

Each time the forecast is updated, the most currently available historical and projected data is used. The current 2020 forecast utilizes:

- Moody's Analytics January 2020 base and consensus economic projections.
- End use equipment and appliance indexes reflect the 2019 update of ITRON's end-use data, which is consistent with the Energy Information Administration's 2019 Annual Energy Outlook
- A calculation of normal weather using the period 1990-2019

The Company also researches weather sensitivity of summer and winter peaks, peak history, hourly shaping of sales, and load research data in a continuous effort to improve forecast accuracy. As a result of continuous improvement efforts, refinements to peak history were identified during the Spring 2020 update, which lowered peak history. Peak history is a key driver in the peak forecast, thus the revisions also contributed to the decrease in the peak forecast. Historical peaks and forecasted peaks can be viewed later in this appendix.

ASSUMPTIONS

Below are the projected average annual growth rates of several key drivers from DEC's Spring 2020 Forecast.

TABLE C-1

KEY DRIVERS

	2021-2035
Real Income	2.9%
Manufacturing Industrial Production Index (IPI)	1.1%
Population	1.5%

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

UTILITY ENERGY EFFICIENCY

Utility Energy Efficiency (UEE) Programs continue to have a large impact in the acceleration of the adoption of energy efficiency. When including the energy and peak impacts of UEE, careful attention must be paid to avoid the double counting of UEE efficiencies with the naturally occurring efficiencies included in the SAE modeling approach. To ensure there is not a double counting of these efficiencies, the forecast "rolls off" the UEE savings at the conclusion of its measure life. For example, if the accelerated benefit of a residential UEE program is expected to have occurred 7 years before the energy reduction program would have been otherwise adopted, then the UEE effects after year 7 are subtracted ("rolled off") from the total cumulative UEE. With the SAE model's framework, the naturally occurring appliance efficiency trends replace the rolled off UEE benefits serving to continue to reduce the forecasted load resulting from energy efficiency adoption.

The table below illustrates this process on sales:

TABLE C-2

UEE PROGRAM LIFE PROCESS (GWH)

YEAR	FORECAST BEFORE UEE	HISTORICAL UEE ROLL OFF	FORECAST WITH HISTORICAL ROLL OFF	FORECASTED UEE INCREMENTAL ROLL ON	FORECASTED UEE INCREMENTAL ROLL OFF	UEE TO SUBTRACT FROM FORECAST	FORECAST AFTER UEE
2021	91,601	8	91,609	(1,269)	657	(612)	90,997
2022	92,121	42	92,162	(1,974)	985	(988)	91,174
2023	92,757	106	92,863	(2,667)	1,314	(1,353)	91,541
2024	93,404	217	93,622	(3,344)	1,644	(1,700)	91,981
2025	93,647	375	94,022	(4,003)	1,975	(2,029)	92,292
2026	94,141	562	94,702	(4,631)	2,306	(2,325)	92,677
2027	94,657	754	95,411	(5,222)	2,640	(2,582)	93,129
2028	95,236	931	96,167	(5,777)	2,985	(2,792)	93,677
2029	95,802	1,070	96,872	(6,294)	3,360	(2,933)	94,242
2030	96,371	1,162	97,533	(6,774)	3,789	(2,985)	94,852
2031	97,018	1,218	98,236	(7,229)	4,241	(2,987)	95,554
2032	97,626	1,242	98,869	(7,675)	4,715	(2,959)	96,216
2033	98,119	1,250	99,370	(8,118)	5,240	(2,878)	96,799
2034	98,625	1,250	99,875	(8,558)	5,793	(2,766)	97,419
2035	99,158	1,250	100,409	(8,997)	6,423	(2,574)	98,145

ROOFTOP SOLAR AND ELECTRIC VEHICLES

Rooftop solar photovoltaic (PV) and electric vehicles (EVs) are considered load modifiers: behind-the-meter solar PV generation reduces the effective load that Duke Energy serves, while plug-in EV charging increases load on the system. Rooftop solar generation and EV load are forecasted independently and then combined with base load and UEE impacts to produce the final electric load forecast. Impacts from existing rooftop solar and EVs are embedded in the historical data that the base load forecast is derived from. Therefore, forecasts for rooftop solar and EVs include impacts from only incremental or “net new” resources projected to be added within the planning horizon.

With the variable characteristics of solar generation and mobility of EVs, utilities will need to employ advanced system controls and/or time-of-use incentives for optimal grid management in order to provide

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safe, reliable and cost-effective service to customers. Given that DEC does not currently have dispatch control of rooftop solar or EVs, DEC's load forecast accounts for the variability of uncontrolled generation and charging. If advanced controls are employed in the future, the forecasted shape would better align with system capabilities and needs.

The markets for rooftop solar and EVs are growing rapidly, so it will become increasingly important to understand and accurately forecast their impacts on electric load. Additional discussion related to regulatory policy and technology can be found in Appendix E.

ROOFTOP SOLAR

Rooftop solar refers to behind-the-meter solar PV generation for residential, commercial and industrial customers. Energy produced by the solar array is consumed by the customer, offsetting their demand on the electric grid. Any excess energy is exported to the grid and credited to the customer at full retail rates under current net energy metering (NEM) policies in North and South Carolina. Both NC and SC have requirements to revisit their NEM tariffs, so while DEC assumes there will be changes to the current program within the planning horizon, it is not yet clear what those changes may be. For this IRP, DEC assumes that NEM tariffs will evolve to more closely align with the cost to serve rooftop solar customers, such that bill savings would gradually decrease over time. This reduction is offset by declining technology costs and increased customer preferences for self-generation, leading to a forecasted net increase in rooftop solar adoption.

Rooftop solar exports are beneficial as a source of carbon-free energy, but present challenges for grid operators due to intermittency associated with solar generation, reduced visibility of the resource and lack of control of energy supply.

Under full retail net metering policy, rooftop solar systems have typically been sized to offset 100% of a customer's annual average demand, within the constraints of state policy. Residential customers are limited to 20 kW-AC, and non-residential customers are limited to the lesser of 1 MW-AC or 100% demand per NC HB 589 and SC Act 62.

TABLE C-3
AVERAGE ROOFTOP SOLAR CAPACITY (kW-AC)

CUSTOMER CLASS	DEC-NC	DEC-SC
Residential	6.2	8.2
Non-residential	77	118

The rooftop solar generation forecast is derived from a series of capacity forecasts and hourly production profiles tailored to residential, commercial and industrial customer classes.

Each capacity forecast is the product of a customer adoption forecast and an average capacity value. Adoption forecasts are based on linear regression modeling in Itron MetrixND using customer payback period as the primary independent variable. Payback periods are a function of installed cost, regulatory incentives and electric bill savings. Historical and projected technology costs are provided by Navigant. Projected incentives and bill savings are based on current regulatory policies and input from internal subject matter experts. Average capacity values are based on trends in historical adoption.

Hourly production profiles have “12x24” resolution meaning there is one 24-hour profile for each month. Profiles are derived from actual production data, where available, and solar PV modeling. Modeling is performed in PVsyst using over 20 years of historical irradiance data from Solar Anywhere and Solcast. Models are created for 13 irradiance locations across DEC’s service area and 21 tilt/azimuth configurations. Results are combined on a weighted average basis to produce final profiles.

Table C-4 shows the projected incremental additions of rooftop solar customers, along with the impacts on capacity and energy, in NC and SC, at the beginning and end of the planning horizon.

TABLE C-4

ROOFTOP SOLAR, NET NEW FROM 2020

YEAR	STATE	NUMBER OF CUSTOMERS	PERCENT OF CUSTOMERS	CAPACITY (MW)	ENERGY (MWH/YEAR)
2021	NC	10,600	0.5%	105	111,000
	SC	3,200	0.5%	29	26,000
2035	NC	79,100	3.1%	745	984,000
	SC	67,000	9.1%	582	710,000

ELECTRIC VEHICLES

EV charging represents a significant opportunity for load growth in the planning horizon. Wood Mackenzie projects EV charging infrastructure to nearly quintuple by 2025[1], and BloombergNEF projects EVs to increase U.S. load by 2% in 2030 and 10% in 2040[2].

Duke Energy's EV load forecast is derived from a series of EV forecasts and load profiles.

The Electric Power Research Institute (EPRI) provides EV forecasts specific to DEC's service area for three adoption cases (low, medium and high) and five vehicle types. In recent years Duke Energy has used EPRI's medium adoption case with minor adjustments as needed for known or expected changes in the market. Vehicle types include plug-in EVs with 10-, 20- and 40-mile range and fully electric vehicles with 100 and 250-mile range.

Unique hourly load profiles (kWh per vehicle per day) are developed internally for each vehicle type, for weekdays and weekends, and for residential and public charging.

[1] Wood Mackenzie: US DER Outlook (June 2020).

[2] BloombergNEF: 2020 Electric Vehicle Outlook: U.S. Update (June 2020).

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Table C-5 shows the projected incremental additions of EVs in operation, along with the impacts on energy, at the beginning and end of the planning horizon.

TABLE C-5

ELECTRIC VEHICLES, NET NEW FROM 2020, INCLUDES NC AND SC

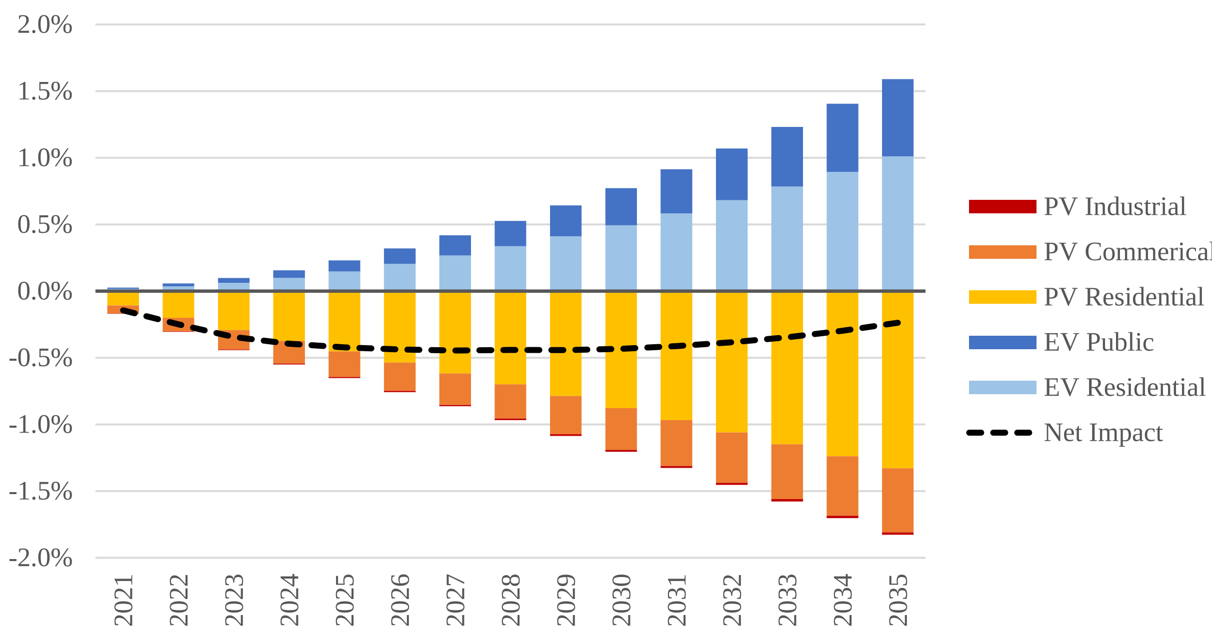
YEAR	EVS IN OPERATION	PERCENT OF VEHICLE FLEET	LOAD (MWH/YEAR)
2021	17,800	0.2%	21,000
2035	417,000	7.3%	1,474,000

NET IMPACT OF ROOFTOP SOLAR AND ELECTRIC VEHICLES

Figures C-1, C-2 and C-3 illustrate the impacts on annual energy, winter peak demand and summer peak demand from rooftop solar and EVs by customer class across the planning horizon.

FIGURE C-1

PERCENT IMPACT OF PV AND EV ON ANNUAL LOAD, NET NEW FROM 2020



Corrected 11.06.2020

FIGURE C-2

PERCENT IMPACT OF PV AND EV ON WINTER PEAK LOAD, NET NEW FROM 2020

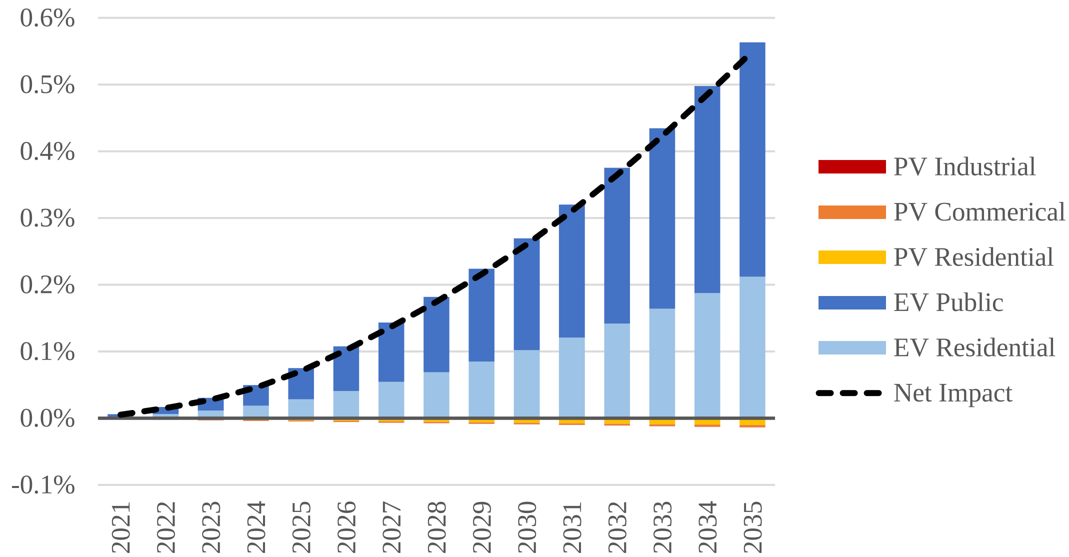
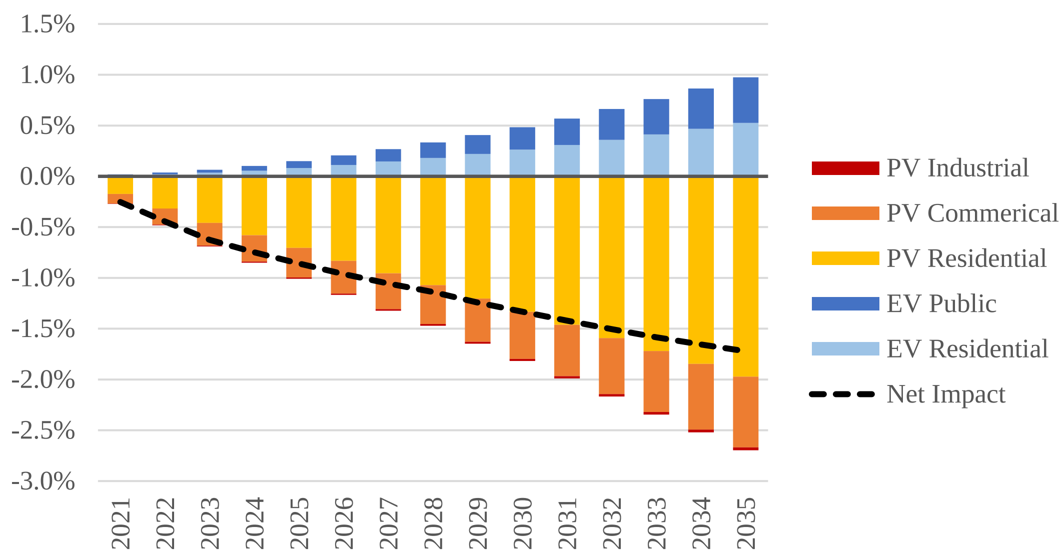


FIGURE C-3

PERCENT IMPACT OF PV AND EV ON SUMMER PEAK LOAD, NET NEW FROM 2020



Corrected 11.06.2020

CUSTOMER GROWTH

Tables C-6 and C-7 show the history and projections for DEC customers.

TABLE C-6

RETAIL CUSTOMERS (ANNUAL AVERAGE IN THOUSANDS)

YEAR	RESIDENTIAL CUSTOMERS	COMMERCIAL CUSTOMERS	INDUSTRIAL CUSTOMERS	OTHER CUSTOMERS	RETAIL CUSTOMERS
2010	2,034	333	7	14	2,389
2011	2,041	335	7	14	2,397
2012	2,053	337	7	14	2,411
2013	2,068	339	7	14	2,428
2014	2,089	342	7	15	2,452
2015	2,117	345	6	15	2,484
2016	2,148	349	6	15	2,519
2017	2,182	354	6	15	2,557
2018	2,215	358	6	17	2,596
2019	2,261	362	6	22	2,651
Avg. Annual Growth Rate	1.2%	0.9%	-2.0%	5.0%	1.2%

TABLE C-7

RETAIL CUSTOMERS (THOUSANDS, ANNUAL AVERAGE)

YEAR	RESIDENTIAL CUSTOMERS	COMMERCIAL CUSTOMERS	INDUSTRIAL CUSTOMERS	OTHER CUSTOMERS	RETAIL CUSTOMERS
2021	2,324	367	6	23	2,721
2022	2,362	369	6	23	2,761
2023	2,405	371	6	24	2,805
2024	2,447	373	6	24	2,850
2025	2,489	374	6	24	2,894
2026	2,529	376	6	25	2,936
2027	2,568	378	6	25	2,976
2028	2,606	379	6	25	3,016
2029	2,643	381	6	25	3,055
2030	2,680	382	6	26	3,094
2031	2,718	383	5	26	3,133
2032	2,755	385	5	26	3,171
2033	2,791	386	5	27	3,209
2034	2,826	388	5	27	3,246
2035	2,860	389	5	27	3,281
Avg. Annual Growth Rate	1.5%	0.4%	-1.1%	1.1%	1.3%

ELECTRICITY SALES

Table C-8 shows the actual historical gigawatt hour (GWh) sales. As a note, the values in Table C-8 are not weather adjusted Sales.

TABLE C-8

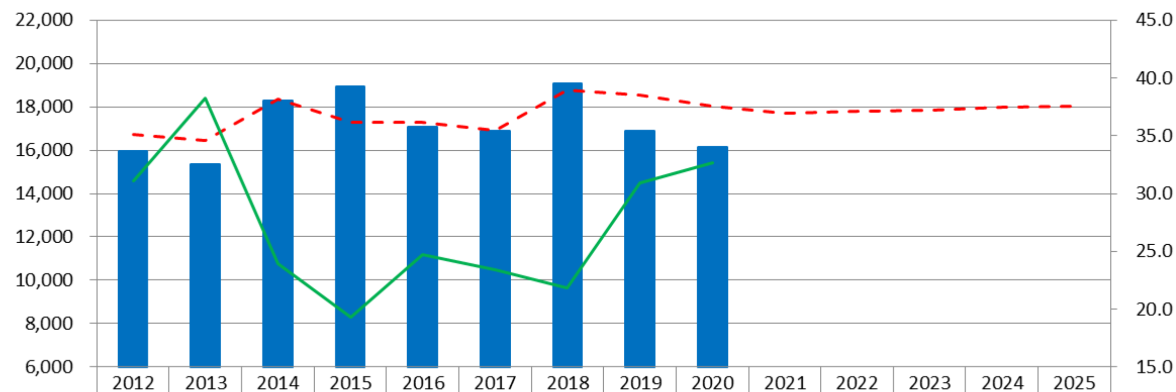
ELECTRICITY SALES (GWH)

YEAR	RESIDENTIAL GWH	COMMERCIAL GWH	INDUSTRIAL GWH	MILITARY & OTHER GWH	RETAIL GWH	WHOLESALE GWH	TOTAL SYSTEM GWH
2010	30,049	27,968	20,618	287	78,922	5,166	84,088
2011	28,323	27,593	20,783	287	76,986	4,866	81,852
2012	26,279	27,476	20,978	290	75,023	5,176	80,199
2013	26,895	27,765	21,070	293	76,023	5,824	81,847
2014	27,976	28,421	21,577	303	78,277	6,559	84,836
2015	27,916	28,700	22,136	305	79,057	6,916	85,973
2016	27,939	28,906	21,942	304	79,091	7,614	86,705
2017	26,593	28,388	21,776	301	77,059	7,558	84,617
2018	29,717	29,656	21,720	306	81,399	8,889	90,288
2019	28,861	29,628	21,299	320	80,109	8,317	88,426
Avg. Annual Growth Rate	-0.4%	0.6%	0.4%	1.2%	0.2%	5.4%	0.6%

SYSTEM PEAKS

Figures C-4 and C-5 show the historical actual and weather normalized peaks for the system:

FIGURE C-4
DEC ACTUAL AND WEATHER NORMAL WINTER PEAKS

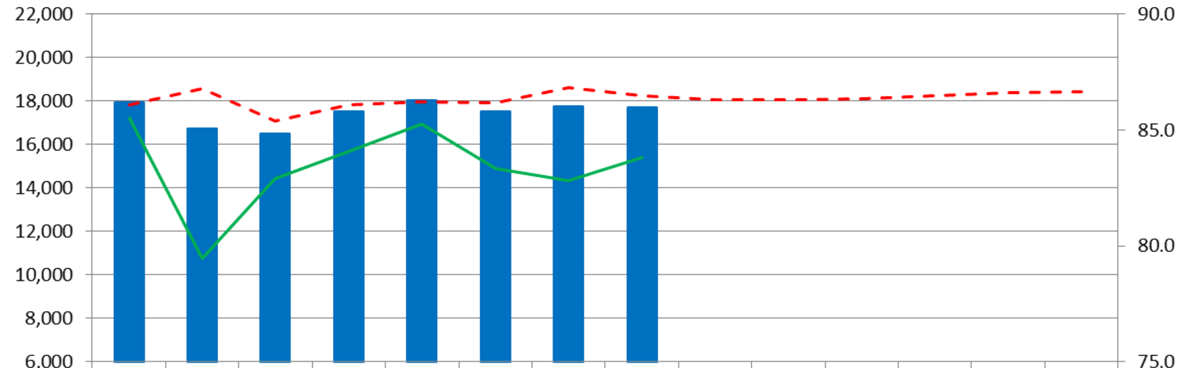


	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Actual	15,962	15,363	18,275	18,931	17,073	16,883	19,077	16,880	16,132					
WN Peak/Forecast	16,733	16,464	18,362	17,294	17,305	16,908	18,783	18,548	18,038	17,725	17,804	17,859	17,962	18,031
Temp	31.1	38.3	23.9	19.4	24.7	23.4	21.9	30.9	32.7					

Note: WN Peak/Forecast values in years 2021-2025 are forecasted peak values from the 2020 Spring Forecast. The Temperatures are the average daily temperature on the day of the peak.

FIGURE C-5

DEC ACTUAL AND WEATHER NORMAL SUMMER PEAKS



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Actual	17,933	16,757	16,501	17,529	18,037	17,539	17,779	17,736						
WN Peak/Forecast	17,822	18,593	17,093	17,832	17,992	17,917	18,613	18,233	18,044	18,086	18,110	18,268	18,388	18,458
Temp	85.5	79.5	82.9	84.1	85.3	83.3	82.8	83.8						

Note: WN Peak/Forecast values in years 2020-2025 are forecasted peak values from the 2020 Spring Forecast. The Temperatures are the average daily temperature on the day of the peak.

FORECAST RESULTS

A tabulation of the utility's sales and peak forecasts are shown as charts below:

- Table C-9: Forecasted energy sales by class (Including the impacts of UEE, rooftop solar, and electric vehicles)
- Table C-10: Forecast energy sales – gross load to net load (walkthrough of impacts from UEE, rooftop solar, electric vehicles and voltage control program)
- Table C-11: Summary of the load forecast without UEE programs and excluding any impacts from demand reduction programs
- Table C-12: Summary of the load forecast with UEE programs and excluding any impacts from demand reduction programs

These projections include Wholesale, and all the loads and energy in the tables and charts below are at generation, except for the class sales forecast, which is at meter.

Load duration curves, with and without UEE programs are shown as Figures C-6 and C-7.

The values in these tables reflect the loads that Duke Energy Carolinas is contractually obligated to provide and cover the period from 2021 to 2035.

TABLE C-9

FORECASTED ENERGY SALES BY CLASS

YEAR	RESIDENTIAL GWH	COMMERCIAL GWH	INDUSTRIAL GWH	OTHER GWH	RETAIL GWH
2021	28,612	29,257	20,909	320	79,098
2022	28,944	29,356	20,815	319	79,434
2023	29,271	29,461	20,677	317	79,725
2024	29,649	29,572	20,540	316	80,075
2025	29,917	29,668	20,423	314	80,321
2026	30,192	29,803	20,322	311	80,628
2027	30,467	29,958	20,267	309	81,001
2028	30,757	30,143	20,247	306	81,453
2029	31,043	30,332	20,252	303	81,929
2030	31,346	30,528	20,270	300	82,445
2031	31,670	30,722	20,283	297	82,971
2032	32,023	30,906	20,270	294	83,492
2033	32,372	31,085	20,253	290	84,000
2034	32,723	31,278	20,244	287	84,532
2035	33,074	31,516	20,289	284	85,163
Avg. Annual Growth Rate	1.0%	0.5%	-0.2%	-0.8%	0.5%

NOTE: Values are at meter.

TABLE C-10

FORECASTED ENERGY SALES – GROSS LOAD TO NET LOAD

YEAR	GROSS RETAIL SALES	ENERGY EFFICIENCY	ROOFTOP SOLAR	ELECTRIC VEHICLES	VOLTAGE CONTROL (IVVC)	NET RETAIL SALES
2021	79,826	(612)	(138)	21		79,098
2022	80,625	(988)	(249)	46		79,434
2023	81,389	(1,353)	(362)	81	(30)	79,725
2024	82,160	(1,700)	(453)	129	(60)	80,075
2025	82,998	(2,029)	(542)	191	(298)	80,321
2026	83,619	(2,325)	(634)	268	(299)	80,628
2027	84,260	(2,582)	(730)	353	(301)	81,001
2028	84,924	(2,792)	(827)	450	(302)	81,453
2029	85,548	(2,933)	(938)	555	(303)	81,929
2030	86,111	(2,985)	(1,051)	674	(304)	82,445
2031	86,628	(2,987)	(1,170)	806	(305)	82,971
2032	87,100	(2,959)	(1,296)	954	(307)	83,492
2033	87,498	(2,878)	(1,423)	1,111	(308)	84,000
2034	87,878	(2,766)	(1,556)	1,285	(309)	84,532
2035	88,268	(2,574)	(1,694)	1,474	(311)	85,163

NOTE: Values are at meter.

TABLE C-11

SUMMARY OF THE LOAD FORECAST WITHOUT UEE PROGRAMS AND EXCLUDING ANY IMPACTS FROM DEMAND REDUCTION PROGRAMS

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2021	18,198	17,795	91,609
2022	18,284	17,933	92,162
2023	18,498	18,042	92,863
2024	18,670	18,195	93,622
2025	18,787	18,334	94,022
2026	18,976	18,493	94,702
2027	19,181	18,607	95,411
2028	19,358	18,790	96,167
2029	19,501	18,933	96,872
2030	19,738	19,074	97,533
2031	19,907	19,226	98,236
2032	20,124	19,393	98,869
2033	20,237	19,502	99,370
2034	20,420	19,605	99,875
2035	20,533	19,752	100,409
Avg. Annual Growth Rate	0.9%	0.7%	0.7%

Corrected 11.06.2020

FIGURE C-6

LOAD DURATION CURVE WITHOUT ENERGY EFFICIENCY PROGRAMS AND BEFORE DEMAND REDUCTION PROGRAMS

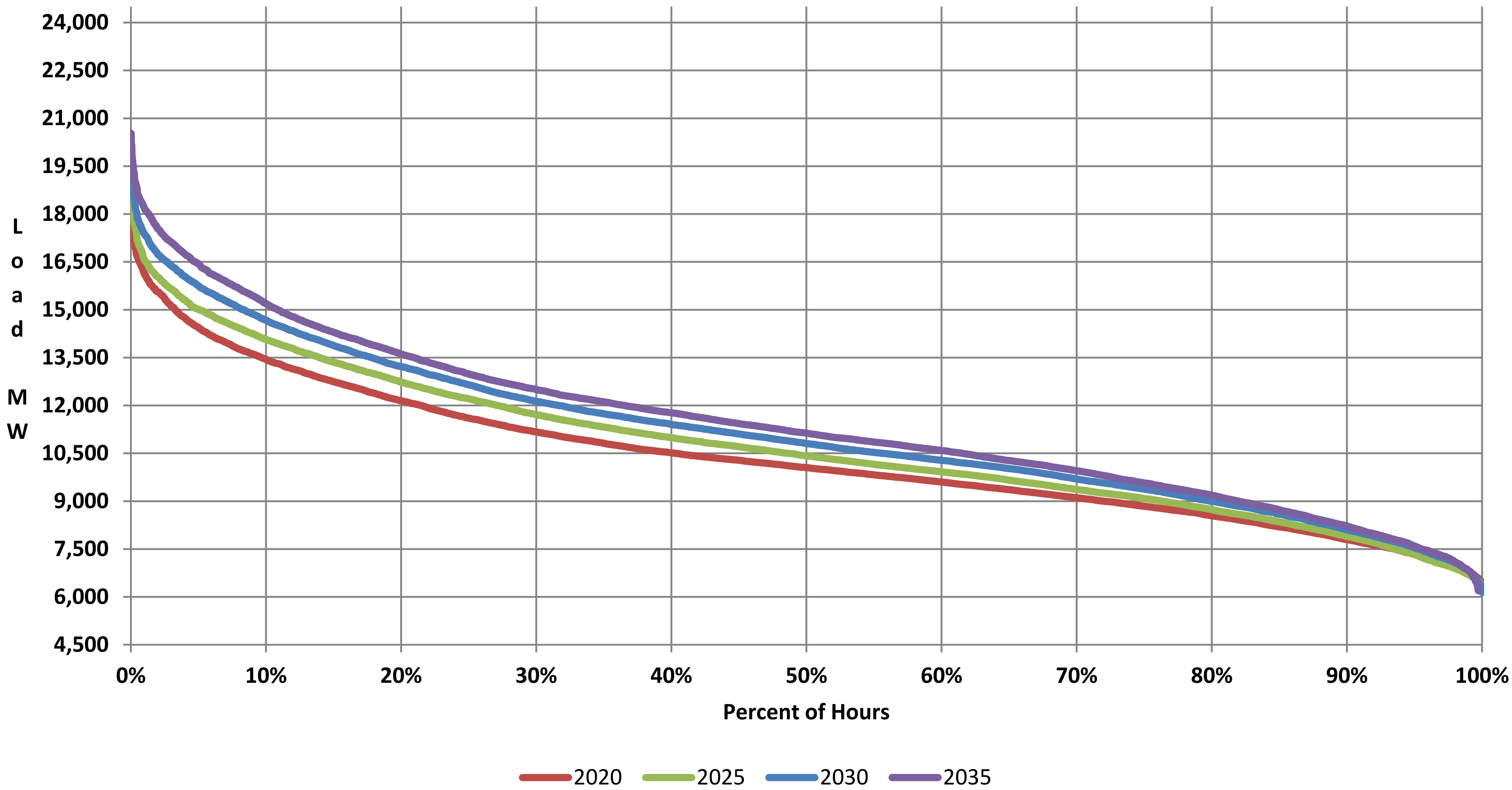


TABLE C-12

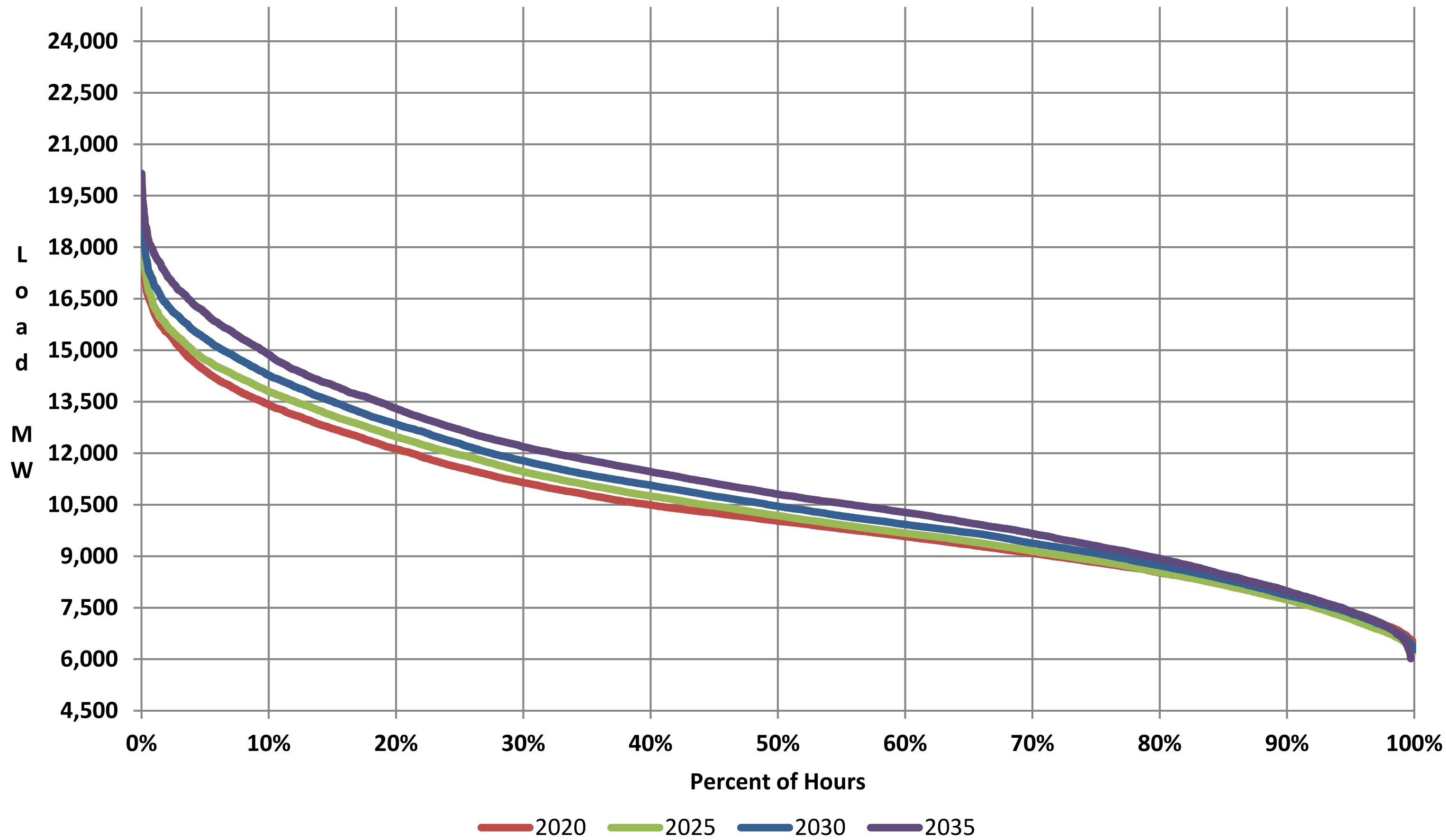
SUMMARY OF THE LOAD FORECAST WITH UEE PROGRAMS AND EXCLUDING ANY IMPACTS FROM DEMAND REDUCTION PROGRAMS

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2021	18,086	17,725	90,997
2022	18,110	17,804	91,174
2023	18,268	17,859	91,541
2024	18,388	17,962	91,981
2025	18,458	18,031	92,292
2026	18,603	18,148	92,677
2027	18,769	18,225	93,129
2028	18,917	18,380	93,677
2029	19,037	18,503	94,242
2030	19,266	18,637	94,852
2031	19,434	18,790	95,554
2032	19,655	18,962	96,216
2033	19,776	19,082	96,799
2034	20,013	19,200	97,419
2035	20,154	19,375	98,145
Avg. Annual Growth Rate	0.8%	0.6%	0.5%

Tables 12-E and 12-F differ from these values due to a 98 MW backstand contract with North Carolina Electric Municipal Co-op (NCEMC) throughout the study period.

FIGURE C-7

LOAD DURATION CURVE WITH ENERGY EFFICIENCY PROGRAMS & BEFORE DEMAND REDUCTION PROGRAMS



Corrected 11.06.2020

ENERGY EFFICIENCY, DEMAND SIDE MANAGEMENT AND VOLTAGE OPTIMIZATION

Corrected 11.06.2020

APPENDIX D: ENERGY EFFICIENCY, DEMAND-SIDE MANAGEMENT AND VOLTAGE OPTIMIZATION

CURRENT ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT PROGRAMS

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

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

Following are the EE and DSM programs available through DEC as of December 31, 2019:

RESIDENTIAL EE PROGRAMS	NON-RESIDENTIAL EE PROGRAMS	RESIDENTIAL DSM PROGRAMS	NON-RESIDENTIAL DSM PROGRAMS
Energy Efficient Appliances and Devices	Non-Residential Smart $aver® Energy Efficient Products and Assessment	Power Manager	PowerShare®
Energy Efficiency Education	Non-Residential Smart $aver® Performance Incentive		Interruptible Service (IS)
Multi-Family Energy Efficiency	Small Business Energy Saver		Standby Generator (SG)
My Home Energy Report			EnergyWise® Business
Income-Qualified Energy Efficiency and Weatherization Assistance			
Energy Assessments			
Smart $aver® Energy Efficiency			

Corrected 11.06.2020

ENERGY EFFICIENCY PROGRAMS

Energy Efficiency programs are typically non-dispatchable education or incentive-based programs. Energy and capacity savings are achieved by changing customer behavior or through the installation of more energy-efficient equipment or structures. All cumulative effects (gross of Free Riders, at the Plant[1]) since the inception of these existing programs through the end of 2019 are summarized below. Please note that the cumulative impacts listed below include the impact of any Measurement and Verification performed since program inception and also note that a "Participant" in the information included below is based on the unit of measure for the specific energy efficiency measure (e.g. number of bulbs, kWh of savings, tons of refrigeration, etc.), and may not be the same as the number of customers that actually participate in these programs. The following provides more detail on DEC's existing EE programs:

RESIDENTIAL EE PROGRAMS

ENERGY EFFICIENT APPLIANCES AND DEVICES PROGRAM

The Energy Efficient Appliances and Devices Program provides incentives to residential customers for installing energy efficient appliances and devices to drive reductions in energy usage. The program includes the following measures:

- Energy Efficient Lighting: DEC customers can take advantage of several program options and delivery mechanisms to improve lighting efficiency, including:

    a. The Free LED program offered free 9-watt A19 Light Emitting Diodes (LED) lamps to install in high-use fixtures through multiple channels to eligible customers. The on-demand ordering platform enabled eligible customers to request LEDs and have them shipped directly to their homes. This program concluded on June 30, 2020.

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

b. The Duke Energy Savings Store is an extension of the on-demand ordering platform enabling eligible customers to purchase specialty bulbs and have them shipped directly to their homes. The Store offers a variety LEDs including; Reflectors, Globes, Candelabra, 3-Way, Dimmable and A-Line type bulbs. The program will no longer offer A-Line bulb incentives after 2020.

c. The Retail Lighting program partners with retailers and manufacturers across North and South Carolina to provide price markdowns on customer purchases of efficient lighting. Product mix includes Energy Star rated standard, reflector, and specialty LEDs, and fixtures. Participating retailers include a variety of channel types, including Big Box, DIY, Club, and Discount stores.

- Energy Efficient Water Heating and Usage: This program component encourages the adoption of low flow showerheads and faucet aerators, water heater insulation, and pipe wrap.

- Other Energy Efficiency Products and Services: Other energy efficient measures recently added to the program are Wi-Fi enabled smart thermostats, smart strips, and LED fixtures.

This program previously offered variable speed pool pump and heat pump water heaters, however, in late 2017 those measures were moved to the Residential Smart $aver® Energy Efficiency Program.

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

ENERGY EFFICIENT APPLIANCES AND DEVICES				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	63,803,127	2,476,134	323,988	84,366

Corrected 11.06.2020

ENERGY EFFICIENCY EDUCATION PROGRAM

The Energy Efficiency Education Program is an energy efficiency program available to students in grades K-12 enrolled in public and private schools who reside in households served by Duke Energy Carolinas. The Program provides principals and teachers with an innovative curriculum that educates students about energy, resources, how energy and resources are related, ways energy is wasted and how to be more energy efficient. The centerpiece of the current curriculum is a live theatrical production performed by two professional actors that is focused on concepts such as energy, renewable fuels and energy efficiency.

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

ENERGY EFFICIENCY EDUCATION PROGRAM FOR SCHOOLS				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	234,148	57,948	10,307	3,859

MULTI-FAMILY ENERGY EFFICIENCY PROGRAM

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

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

MULTI-FAMILY ENERGY EFFICIENCY				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	2,854,090	144,261	15,397	10,708

MY HOME ENERGY REPORT PROGRAM

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

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

MY HOME ENERGY REPORT				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	1,339,152	328,439	91,387	79,435

INCOME-QUALIFIED ENERGY EFFICIENCY AND WEATHERIZATION ASSISTANCE PROGRAM

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

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

- **Weatherization and Equipment Replacement Program (WERP)** recognizes the existence of customers whose EE needs surpass the standard low-cost measure offerings provided through NES. WERP is available to income-qualified customers in the Duke Energy Carolinas service territory for existing, individually metered, single-family, condominiums, and mobile homes. Funds are available for weatherization measures and/or heating system replacement with a 15 or greater SEER heat pump. A full energy audit of the residence is used to determine the measures eligible for funding. Customers are placed into a tier based on energy usage, where Tier 1 provides up to $600 for energy efficiency services; while Tier 2 provides up to $4,000 for energy efficiency services, including insulation, thus allowing high energy users to receive more extensive weatherization measures.

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

- **WERP** and **RRP** are delivered in coordination with State agencies that administer the state's weatherization programs.

LOW INCOME ENERGY EFFIENCY AND WEATHERIZATION ASSISTANCE PROGRAM				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	75,441	41,064	5,821	4,980

ENERGY ASSESSMENTS PROGRAM

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

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

RESIDENTIAL ENERGY ASSESSMENTS				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	197,969	80,591	11,941	2,470

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

PERSONALIZED ENERGY REPORT			
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)	
		MWH ENERGY	PEAK SKW
December 31, 2019	86,333	24,502	2,790
ONLINE HOME ENERGY COMPARISON REPORT			
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)	
		MWH ENERGY	PEAK SKW
December 31, 2019	12,902	3,547	387

SMART $AVER® ENERGY EFFICIENCY PROGRAM

The Smart $aver® Energy Efficiency Program offers measures that allow eligible Duke Energy Carolinas customers to take action and reduce energy consumption in their home. The Program offering provides incentives for the purchase and installation of eligible central air conditioner or heat pump replacements in addition to Quality Installations and Wi-Fi enabled Smart Thermostats when installed and programmed at the time of installation of the heating ventilation and air conditioning (HVAC) system. Program participants may also receive an incentive for attic insulation/air sealing, duct sealing, variable speed pool pumps, and heat pump water heaters.

The prescriptive and a-la-carte design of the program allows customers to implement individual, high priority measures in their homes without having to commit to multiple measures and higher price tags. A referral channel provides free, trusted referrals to customers seeking reliable, qualified contractors for their energy saving home improvement needs. This program previously offered HVAC Tune-Ups and Duct Insulation, however, those measures were removed due to no longer being cost-effective.

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

SMART SAVER ENERGY EFFICIENCY				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	171,758	93,689	28,016	9,352

NON-RESIDENTIAL EE PROGRAMS

NON-RESIDENTIAL SMART $AVER ENERGY EFFICIENT PRODUCTS AND ASSESSMENT PROGRAM

The Non-Residential Smart $aver Energy Efficient Products and Assessment Program provides incentives to DEP commercial and industrial customers to install high efficiency equipment in applications involving new construction and retrofits and to replace failed equipment.

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

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

- **Prescriptive Measures:** Customers receive incentive payments after the installation of certain high efficiency equipment found on the list of pre-defined prescriptive measures, including lighting; heating, ventilating and air conditioning equipment; and refrigeration measures and equipment. The program will no longer offer A-Line bulb incentives after 2020.

- **Custom Measures:** Custom measures are designed for customers with electrical energy saving projects involving more complicated or alternative technologies, whole-building projects, or those measures not included in the Prescriptive measure list. The intent of the Program is to encourage the implementation of energy efficiency projects that would not otherwise be completed without the Company's technical or financial assistance. Unlike the Prescriptive portion of the program, all Custom measure incentives require pre-approval prior to the project implementation. The program will no longer offer A-Line bulb incentives after 2020.

- **Energy Assessments and Design Assistance:** Incentives are available to assist customers with energy studies such as energy audits, retro commissioning, and system-specific energy audits for existing buildings and with design assistance such as energy modeling for new construction. Customers may use a contracted Duke Energy vendor to perform the work or they may select their own vendor. Additionally, the Program assists customers who identify measures that may qualify for Smart $aver Incentives with their applications. Pre-approval is required. In 2019, the program modified its approach to a Virtual Energy Assessment utilizing an energy modeling software to complete the assessment in 2-3 weeks at a lower cost.

NON-RESIDENTIAL SMART SAVER ENERGY EFFICIENCY PRODUCTS AND ASSESSMENT				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	30,471,766	2,528,566	421,586	165,199

NOTE: Participants have different units of measure.

NON-RESIDENTIAL SMART $AVER PERFORMANCE INCENTIVE PROGRAM

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

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

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

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

NON-RESIDENTIAL SMART SAVER PERFORMANCE INCENTIVE				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	156	9,692	695	745

SMALL BUSINESS ENERGY SAVER PROGRAM

The Small Business Energy Saver Program reduces energy usage through the direct installation of energy efficiency measures within qualifying non-residential customer facilities. Program measures address major end-uses in lighting, refrigeration, and HVAC applications. The program is available to existing non-residential customers that are not opted-out of the Company's EE/DSM Rider and have an average annual demand of 180 kW or less per active account.

Program participants receive a free, no-obligation energy assessment of their facility followed by a recommendation of energy efficiency measures to be installed in their facility along with the projected energy savings, costs of all materials and installation, and up-front incentive amount from Duke Energy Carolinas. The customer makes the final determination of which measures will be installed after receiving the results of the energy assessment. The Company-authorized vendor schedules the installation of the energy efficiency measures at a convenient time for the customer, and electrical subcontractors perform the work.

SMALL BUSINESS ENERGY SAVER				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	342,704,915	386,003	70,787	33,129

DEMAND-SIDE MANAGEMENT PROGRAMS

RESIDENTIAL

POWER MANAGER®

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

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

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

POWER MANAGER©			
CUMULATIVE AS OF:	PARTICIPANTS (CUSTOMERS)	DEVICES (SWITCHES)	SUMMER 2019 CAPABILITY (MW)
December 31, 2019	238,057	286,473	569

The following table shows Power Manager® program activations that were for the general population from June 1, 2018 through December 31, 2019.

POWER MANAGER© PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION
07/15/2019	4:00 PM	6:00 PM	120	275
08/09/2019	4:30 PM	5:00 PM	30	302
09/09/2019	4:00 PM	6:00 PM	120	183
09/12/2019	3:00 PM	6:00 PM	180	230
09/26/2019	4:00 PM	6:00 PM	120	227

Power Manager® added a summer cooling Bring Your Own Thermostat (BYOT) option in late December 2019. Customer acquisition for this program option year to date through June

2020 is 14,500 participants. No activations of this program option have been administered through June 2020.

NON-RESIDENTIAL

DEMAND RESPONSE – CURTAILABLE PROGRAMS

The DEC non-residential demand response portfolio consists of a combination of programs that rely either on the customer's ability to respond to a utility-initiated notification or on receipt of a signal to control customer equipment, including small business thermostats. Customers are offered ongoing incentives commensurate to the amount of load they are capable of curtailing.

The recent Nexant Market Potential Study forecasted minimal summer and winter non-residential DSM growth opportunities in the Carolinas, particularly for the small and medium business segment. Further, given the expected impact of the Enhanced scenario's doubling of incentives on program cost-effectiveness and future DSM rate adjustments, the Base scenario would be considered more applicable for the large non-residential segment. The large business demand response programs are actively marketed to all customer segments that are known to possess the flexibility to curtail load and have demands high enough to comply with program minimums, which means that there is a simultaneous effort to maximize both winter and summer resources. Although they provide for flexibility in contracting for different winter and summer commitments due to seasonal variations in customers' loads and operational characteristics, the programs are designed to incent participants to provide curtailable demand year-round. This allows for availability of the programs even in off-peak months when scheduled generation maintenance, in conjunction with unseasonable temperatures or other weather events, could lead to the need for demand-side management resources.

Duke Energy Carolinas' current curtailable programs include:

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

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

POWERSHARE© MANDATORY			
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	SUMMER 2019 CAPABILITY (MW)	WINTER 2019 CAPABILITY (MW)
December 31, 2019	147	327	307

The following table shows PowerShare® Mandatory program activations that were not for testing purposes from January 1, 2018 through December 31, 2019.

POWERSHARE® MANDATORY PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION (@GEN)
1/2/2018	7:00 am	10:00 am	180	273
1/7/2018	7:30 am	10:30 am	180	203

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

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POWERSHARE® GENERATOR STATISTICS			
AS OF:	PARTICIPANTS	SUMMER 2019 CAPABILITY (MW)	WINTER 2019 CAPABILITY (MW)
December 31, 2019	10	10.5	9.9

The following table shows PowerShare® Generator program activations that were not for testing purposes from January 1, 2018 through December 31, 2019.

POWERSHARE® GENERATOR PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION (@GEN)
1/2/2018	7:00 am	10:00 am	180	9
1/7/2018	7:30 am	10:30 am	180	7

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

POWERSHARE® VOLUNTARY			
AS OF:	PARTICIPANTS	SUMMER 2019 CAPABILITY (MW)	WINTER 2019 CAPABILITY (MW)
December 31, 2019	0	N/A	N/A

There were no PowerShare® Voluntary program activations from January 1, 2018 through December 31, 2019.

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

IS PROGRAM			
AS OF:	PARTICIPANTS	SUMMER 2019 CAPABILITY (MW)	WINTER 2019 CAPABILITY (MW)
December 31, 2019	42	128	113

The following table shows IS program activations that were not for testing purposes from January 1, 2018 through December 31, 2019.

IS PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION (@GEN)
1/2/2018	7:00 AM	10:00 AM	180	95
1/7/2018	7:30 AM	10:30 AM	180	69

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

SG PROGRAM			
AS OF:	PARTICIPANTS	SUMMER 2019 CAPABILITY (MW)	WINTER 2019 CAPABILITY (MW)
December 31, 2019	13	10	10

The following table shows SG program activations that were not for testing purposes from January 1, 2018 through December 31, 2019.

SG PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION (@GEN)
1/2/2018	7:00 AM	10:00 AM	180	9
1/7/2018	7:30 AM	10:30 AM	180	8.5

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

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

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

ENERGYWISE® BUSINESS PROGRAM				
CUMULATIVE AS OF:	PARTICIPANTS*	MW CAPABILITY (@GEN)		MWH ENERGY SAVINGS (@GEN)
		SUMMER	WINTER	
December 31, 2019	12,885	12.1	2.6	635

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

The following table shows **EnergyWise® Business** program activations that were not for testing purposes from January 1, 2018 through December 31, 2019.

ENERGYWISE® BUSINESS PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION
8/28/2018	4:00 pm	6:00 pm	120	7.5
7/2/2019	4:00 pm	6:00 pm	120	9.9
7/17/2019	4:00 pm	6:00 pm	2.0	9.9
9/12/2019	4:00 pm	6:00 pm	2.0	10.5

DISCONTINUED DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAMS

Since the last biennial Resource Plan filing, DEC discontinued the following DSM/EE programs:

- **PowerShare CallOption** – Due to a lack of customer interest, DEC closed the PowerShare CallOption (Rider PSC) program in North Carolina effective January 31, 2018, pursuant to an NCUC Order issued in Docket E-7, Sub 1130, dated August 23, 2017. The Company gained approval to close the program in South Carolina effective August 31, 2018, through PSC Order 2018-581 under Docket 2013-298-E.

FUTURE EE AND DSM PROGRAMS

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

DEC plans to evaluate and consider the addition of cost-effective winter measures to the **Power Manager®** program in 2020. These measures include winter BYOT, water heating control, and heat pump heat strip control.

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

EE AND DSM PROGRAM SCREENING

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

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

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

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

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

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

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

Energy Efficiency and Demand-Side Management Program Forecasts:

FORECAST METHODOLOGY

In 2019, DEC commissioned a new EE market potential study to obtain new estimates of the technical, economic and achievable potential for EE savings within the DEC service area. The final reports (one for South Carolina and one for North Carolina) were prepared by Nexant Inc. and issued in May 2020 with a final revision completed in June 2020.

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

The Nexant market potential study (MPS) included projections of Energy Efficiency impacts over a 25-year period for Base, Enhanced and Avoided Energy Cost Sensitivity Scenario, which were used in conjunction with expected EE savings from DEC's five-year program plan to develop the Base, High and Low Case EE savings forecasts for this IRP.

The Base Case EE savings forecast represents a merging of the projected near-term savings from DEC's five-year plan (2020-2024) with the long-term savings from the Nexant MPS (2030-onward). Savings during the five-year period (2025-2029) between the two sets of projections represents a merging of the two forecasts to ensure a smooth transition.

The High Case EE savings forecast was developed using the same process as the Base case, however; for the Nexant MPS portion of the forecast, the difference between the Avoided Energy Cost Sensitivity and Base Scenarios for all years was added to the Enhanced Case forecast. This method captures the higher EE savings resulting from both the higher avoided energy cost assumptions as well as from increased customer incentives in the Enhanced case.

Finally, the Low Case was developed by applying a reduction factor to the Base Case forecast. Additionally, the cumulative savings projections for the Base, High and Low Case EE forecasts included an assumption that when the EE measures included in the forecast reach the end of their useful lives, the impacts associated with these measures are removed from the future projected EE impacts, a process defined as "rolloff".

The tables below provide the projected MWh load impacts for the Base, High and Low Case forecasts of all DEC EE programs implemented since the approval of the save-a-watt recovery mechanism in 2009 on a Net of Free Riders basis. The Company assumes total EE savings will continue to grow on an annual basis throughout the planning period, however, the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan. Please note that this table includes a column that shows historical EE program savings since the inception of the EE programs in 2009 through the end of 2019, which accounts for approximately an additional 5,200 gigawatt-hour (GWh) of net energy savings. The following forecasts are presented without the effects of "rolloff":

PROJECTED MWH IMPACTS OF EE PROGRAMS
BASE CASE

YEAR	ANNUAL MWH LOAD REDUCTION - NET	
	INCLUDING MEASURES ADDED IN 2020 AND BEYOND	INCLUDING MEASURES ADDED SINCE 2009
2009-19		5,200,658
2020	735,249	5,935,907
2021	1,114,552	6,315,210
2022	1,489,213	6,689,871
2023	1,845,095	7,045,753
2024	2,188,158	7,388,816
2025	2,507,961	7,708,619
2026	2,790,708	7,991,366
2027	3,036,400	8,237,058
2028	3,245,037	8,445,695
2029	3,416,618	8,617,276
2030	3,551,144	8,751,802
2031	3,670,799	8,871,457
2032	3,787,171	8,987,829
2033	3,900,360	9,101,018
2034	4,011,444	9,212,102
2035	4,120,603	9,321,261

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

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PROJECTED MWH IMPACTS OF EE PROGRAMS
HIGH CASE

YEAR	ANNUAL MWH LOAD REDUCTION - NET	
	INCLUDING MEASURES ADDED IN 2020 AND BEYOND	INCLUDING MEASURES ADDED SINCE 2009
2009-19		5,200,658
2020	735,249	5,935,907
2021	1,152,397	6,353,055
2022	1,564,439	6,765,097
2023	1,955,823	7,156,481
2024	2,333,106	7,533,764
2025	2,686,048	7,886,706
2026	3,000,854	8,201,512
2027	3,277,523	8,478,181
2028	3,516,056	8,716,714
2029	3,716,453	8,917,111
2030	3,878,713	9,079,371
2031	4,024,353	9,225,011
2032	4,165,073	9,365,731
2033	4,301,216	9,501,874
2034	4,434,129	9,634,787
2035	4,564,305	9,764,963

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

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PROJECTED MWH IMPACTS OF EE PROGRAMS
LOW CASE

YEAR	ANNUAL MWH LOAD REDUCTION - NET	
	INCLUDING MEASURES ADDED IN 2020 AND BEYOND	INCLUDING MEASURES ADDED SINCE 2009
2009-19		5,200,658
2020	551,437	5,752,095
2021	835,914	6,036,572
2022	1,116,910	6,317,568
2023	1,383,821	6,584,479
2024	1,641,118	6,841,776
2025	1,880,970	7,081,628
2026	2,093,031	7,293,689
2027	2,277,300	7,477,958
2028	2,433,777	7,634,435
2029	2,562,463	7,763,121
2030	2,663,358	7,864,016
2031	2,753,100	7,953,758
2032	2,840,378	8,041,036
2033	2,925,270	8,125,928
2034	3,008,583	8,209,241
2035	3,090,452	8,291,110

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

The MW impacts from the EE programs are included in the Load Forecasting section of this IRP. The tables below provide the projected winter and summer peak MW load impacts of all current and projected DEC DSM programs.

PROJECTED MW LOAD IMPACTS OF DSM PROGRAMS

	WINTER PEAK MW REDUCTION					
YEAR	POWER MANAGER	POWERSHARE MANDATORY	IS	SG	ENERGWISE BUSINESS	TOTAL SUMMER PEAK
2020	0	315	120	10	2	446
2021	0	347	98	2	2	449
2022	4	337	93	2	3	438
2023	6	340	88	2	3	439
2024	8	343	84	2	4	441
2025	13	345	80	1	4	444
2026	19	345	77	1	4	446
2027	28	345	77	1	4	455
2028	40	345	77	1	4	467
2029	56	345	77	1	4	484
2030	77	345	77	1	4	504
2031	101	345	77	1	4	529
2032	128	345	77	1	4	555
2033	154	345	77	1	4	582
2034	179	345	77	1	4	606
2035	199	345	77	1	4	627

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

PROJECTED MW LOAD IMPACTS OF DSM PROGRAMS

	SUMMER PEAK MW REDUCTION					
YEAR	POWER MANAGER	POWERSHARE MANDATORY	IS	SG	ENERGWISE BUSINESS	TOTAL SUMMER PEAK
2020	578	373	108	2	23	1084
2021	590	359	102	2	29	1082
2022	590	362	97	2	34	1086
2023	591	366	92	2	39	1090
2024	591	369	88	2	46	1096
2025	592	370	84	2	46	1094
2026	593	370	82	2	46	1093
2027	595	370	82	2	46	1095
2028	597	370	82	2	46	1097
2029	600	370	82	2	46	1100
2030	603	370	82	2	46	1103
2031	607	370	82	2	46	1107
2032	611	370	82	2	46	1111
2033	615	370	82	2	46	1115
2034	619	370	82	2	46	1119
2035	621	370	82	2	46	1122

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EE SAVINGS VARIANCE SINCE LAST IRP

In response to Order number 7 in the NCUC Order Approving Integrated Resource Plans and REPS Compliance Plans regarding the 2014 Biennial IRP's, the Base Portfolio EE savings forecast of MW and MWh was compared to the 2018 IRP and the cumulative achievements projected in the 2020 IRP at year 2035 of the forecast are approximately 16.7% lower than the cumulative achievements in the 2018 IRP for the same time period as shown in the table below.

For the next 5-years, the Company's projected energy efficiency program adoption is expected to achieve savings within 10% of projections for the same period in the 2018 IRP. However, longer term, the new market potential study (filed as Attachment V of this IRP) has projected that most of the programs which pass economic screening will have reached maturity over the next 10-years resulting in lower future adoption rates in comparison to the previous MPS conducted in 2016. As can be seen in the exhibit below, the near-term variance is positive but decreases in magnitude over time, ultimately becoming negative in the final 7-years of the forecast period based on the projections in the MPS.

The Company will continue to evaluate the results of the MPS in conjunction with the EE/DSM Collaborative and continue to investigate new efficiency measures or programs which may enhance future projections.

BASE CASE COMPARISON TO 2018 DEC IRP					
	2018 IRP		2020 IRP		
	ANNUAL MWH LOAD REDUCTION - NET		ANNUAL MWH LOAD REDUCTION - NET		
YEAR	INCLUDING MEASURES ADDED IN 2018 AND BEYOND	INCLUDING MEASURES ADDED SINCE 2009	INCLUDING MEASURES ADDED IN 2020 AND BEYOND	INCLUDING MEASURES ADDED SINCE 2009	% CHANGE FROM 2018 TO 2020 IRP
2018	457,007	4,553,221			
2019	887,403	4,983,616		5,200,658	4.4%
2020	1,300,965	5,397,178	735,249	5,935,907	10.0%
2021	1,679,020	5,775,233	1,114,552	6,315,210	9.3%
2022	2,053,771	6,149,984	1,489,213	6,689,871	8.8%
2023	2,429,142	6,525,356	1,845,095	7,045,753	8.0%
2024	2,805,135	6,901,349	2,188,158	7,388,816	7.1%
2025	3,181,749	7,277,963	2,507,961	7,708,619	5.9%
2026	3,558,985	7,655,198	2,790,708	7,991,366	4.4%
2027	3,936,841	8,033,054	3,036,400	8,237,058	2.5%
2028	4,315,318	8,411,532	3,245,037	8,445,695	0.4%
2029	4,696,455	8,792,668	3,416,618	8,617,276	-2.0%
2030	5,081,308	9,177,522	3,551,144	8,751,802	-4.6%
2031	5,471,391	9,567,605	3,670,799	8,871,457	-7.3%
2032	5,869,066	9,965,280	3,787,171	8,987,829	-9.8%
2033	6,270,015	10,366,228	3,900,360	9,101,018	-12.2%
2034	6,678,531	10,774,744	4,011,444	9,212,102	-14.5%
2035	7,093,543	11,189,756	4,120,603	9,321,261	-16.7%

PROGRAMS EVALUATED BUT REJECTED

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

Corrected 11.06.2020

INTEGRATED VOLT-VAR CONTROL

PROGRAM DESCRIPTION

Duke Energy Carolinas (DEC) is beginning implementation of an Integrated Volt-Var Control (IVVC) project that will better manage the application and operation of voltage regulators (the Volt) and capacitors (the VAR) on the Duke Energy Carolinas distribution system. DEC would primarily operate IVVC in the form of Conservation Voltage Reduction (CVR). Integrated Voltage/VAR Control (IVVC) is the coordinated control of distribution equipment in substations and on distribution lines to optimize voltages and power factors on the distribution grid. This allows the distribution system to operate as efficiently as possible without violating load and voltage constraints, while supporting the reactive power needs of the bulk power system. IVVC can be implemented through various Substation and Distribution projects included within the Duke Energy Carolinas (DEC) IVVC Evaluation. Currently, communication with and control of substation voltage regulation, substation capacitors, and distribution line voltage regulators on the DEC system is minimal. Additionally, distribution line capacitors have communications, but not remote control, capabilities. Primary projects to install communications and control infrastructure include Substation Voltage Regulator Control Replacement, Substation Capacitor Control Replacement, Distribution Line Voltage Regulator Control Replacement, Distribution Line Capacitor Control Replacement, possible installation of End of Line Medium Voltage Sensors, and two-way communications implementation into these substation and distribution line devices. New Distribution Line Voltage Regulator and Capacitor additions are also possible. Other proposed projects, such as the Self Optimized Grid, overlap in providing some of the infrastructure and capabilities necessary to enable IVVC. Therefore, Duke Energy Carolinas could take advantage of resource and scope opportunities from all the projects combined to make IVVC possible.

IVVC can dynamically optimize the control of substation and distribution 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 integrating substation and distribution line voltage regulators and capacitors into the Distribution Management System (DMS) with two-way communications, automating their operation. The DMS continuously monitors the conditions on the controlled circuits and maintains the desired 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 [conservation voltage reduction (CVR)] at the substation results in a reduction of system loading, creating the benefit of decreased generation. CVR is an operational mode of Volt Var Optimization (VVO) that supports voltage reduction and energy conservation. This provides fuel savings to customers and reduced emissions from the avoided generation.

IVVC provides increased visibility into the status and condition of substation and field devices such as capacitor banks, voltage regulators, and transformer load-tap changers. This added visibility and enhanced voltage control will help manage the integration of distributed energy resources (i.e. solar) by improving the grid's ability to respond to intermittency. Access to additional system data will aid grid operators in the daily operation of the distribution grid and promote reliability. CVR functionality would target a potential 2% voltage reduction on the circuits and substations within the scope of implementation. This scope accounts for approximately 50% of the total circuits and substations across DEC, which account for approximately 70% of current base load. Assuming an average CVR factor of 0.7 (CVR Factor = % Load Reduction / % Voltage Reduction) this 2% voltage reduction is estimated to result in a 1.4% load reduction for enabled circuits. There may be cases where a variation in voltage could impact customers with large motors sensitive to voltage control. The DMS system can be designed to manage distribution circuits serving loads with voltage sensitivities, reducing these impacts. It is expected that CVR functionality would be utilized for the majority of the year. However, CVR mode would provide less demand reduction capability than peak shaving mode. To maximize operational flexibility and value, the IVVC system will also have peak shaving capability and emergency modes of operation. The software within the future enterprise DMS platform will enable IVVC to operate in various modes to provide further customer benefit.

BENEFITS

- Reduced distribution line losses due to lower overall voltage
- More efficient grid due to lower line losses and reduced reactive power
- Less generation fuel consumed and lower emissions due to grid efficiencies
- Integrated control of capacitor banks provides greater ability to reduce reactive power, resulting in less apparent load on the system
- Less peak load on the grid could result in a reduced need to build additional peaking generation
- Optimized control of Volt-VAR devices improves the grid's ability to respond to intermittency
- Helps to manage integration of distributed energy resources

IVVC is part of the proposed Duke Energy Carolinas Grid Improvement Plan. The deployment of an IVVC program for DEC is anticipated to take approximately 4-years. IVVC will become functional upon full integration of the control system, substation components, and distribution line components.

DEC (NORTH CAROLINA & SOUTH CAROLINA) INTEGRATED VOLT VAR CONTROL (IVVC) ANNUAL ESTIMATED ENERGY REDUCTION (KWH) OPERATING CONSERVATION VOLTAGE REDUCTION (CVR) 90% OF THE HOURS*		
YEAR	IVVC DEPLOYMENT (%)	TOTAL REDUCTION (KWH)*
2018	0%	0
2019	0%	0
2020	0%	0
2021	0%	0
2022	0%	0
2023	10%	30,607,478
2024	20%	61,765,891
2025	100%	311,608,922
2026	100%	314,413,403
2027	100%	317,243,123
2028	100%	320,098,311
2029	100%	322,979,196
2030	100%	325,886,009
2031	100%	328,818,983
2032	100%	331,778,354
2033	100%	334,764,359
2034	100%	337,777,238
2035	100%	340,817,233

*(Energy reduction does not account for system losses upstream of distribution retail substations).

DEC (NORTH CAROLINA & SOUTH CAROLINA)
INTEGRATED VOLT VAR CONTROL (IVVC)
ANNUAL ESTIMATED DEMAND REDUCTION (KW)*

Year Round Conservation Voltage Reduction (CVR) Mode Approximately 90% of the Hours

YEAR	IVVC DEPLOYMENT (%)	TOTAL REDUCTION (KW)*
2018	0%	0
2019	0%	0
2020	0%	0
2021	0%	0
2022	0%	0
2023	10%	12,713
2024	20%	25,655
2025	100%	129,431
2026	100%	130,596
2027	100%	131,771
2028	100%	132,957
2029	100%	134,154
2030	100%	135,361
2031	100%	136,580
2032	100%	137,809
2033	100%	139,049
2034	100%	140,301
2035	100%	141,563

*(Demand reduction does not account for system losses upstream of distribution retail substations).

Peak-Shaving Mode Approximately <10% of the Hours

YEAR	IVVC DEPLOYMENT (%)	TOTAL REDUCTION (KW)*
2018	0%	0
2019	0%	0
2020	0%	0
2021	0%	0
2022	0%	0
2023	10%	16,951
2024	20%	34,207
2025	100%	172,575
2026	100%	174,128
2027	100%	175,695
2028	100%	177,277
2029	100%	178,872
2030	100%	180,482
2031	100%	182,106
2032	100%	183,745
2033	100%	185,399
2034	100%	187,067
2035	100%	188,751

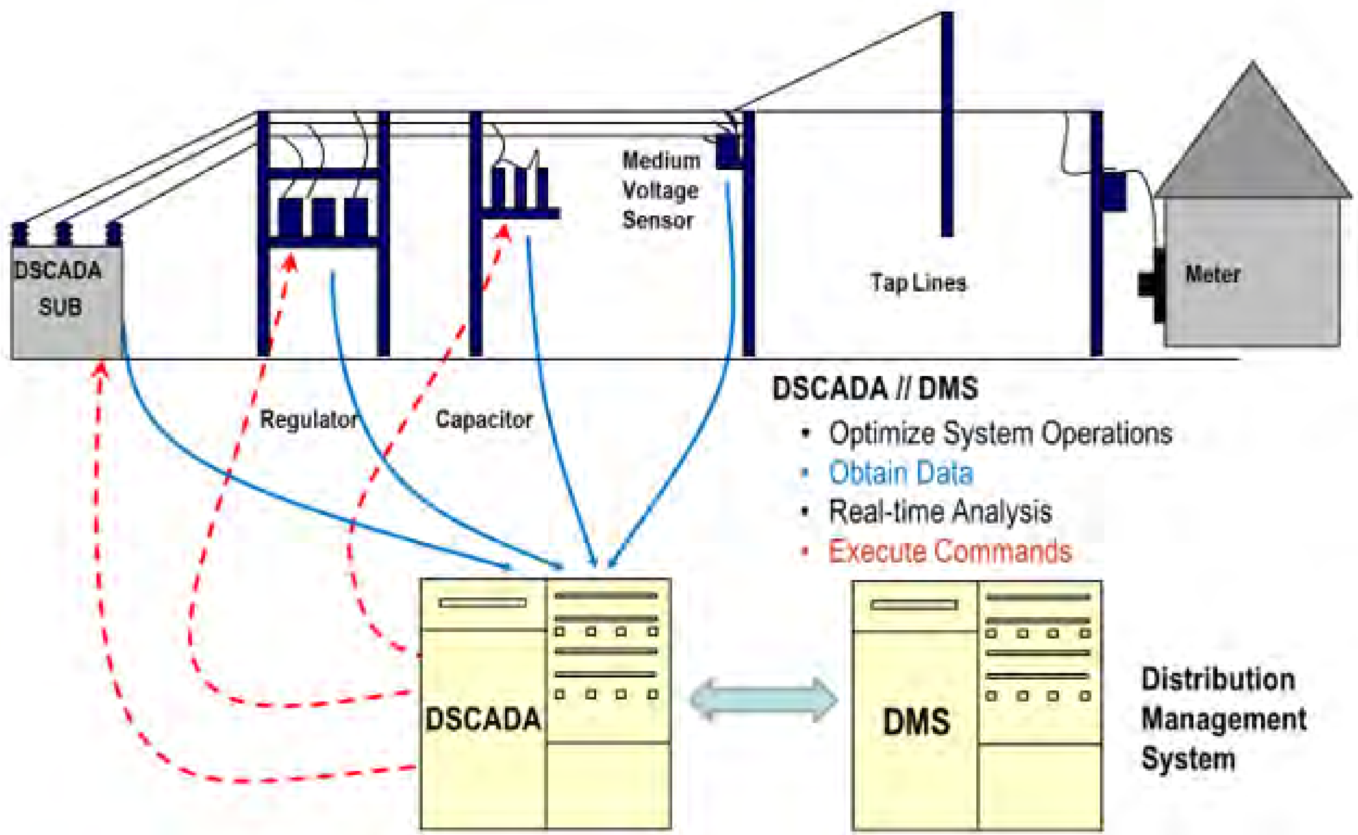
*(Demand reduction does not account for system losses upstream of distribution retail substations).

Corrected 11.06.2020

VOLT - VAR OPTIMIZATION TERMINOLOGY

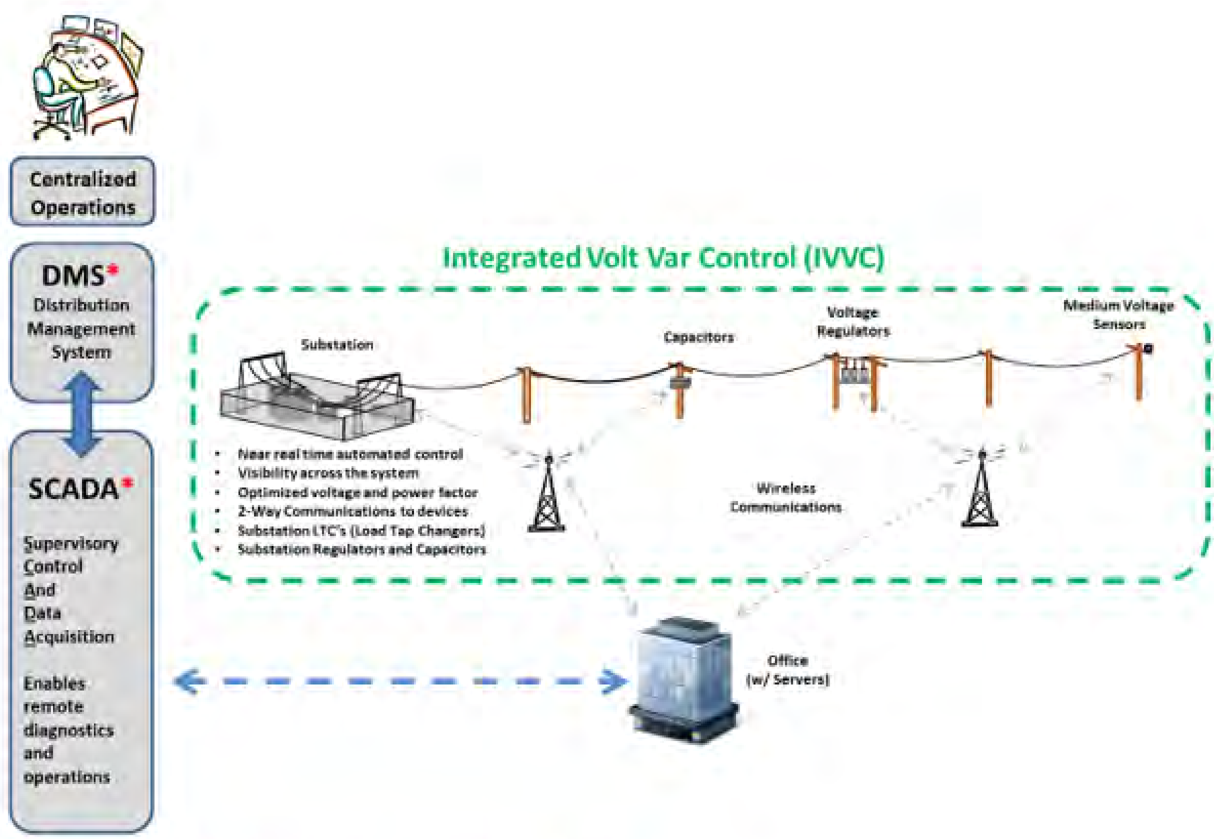
VVO	*Volt-VAR Optimization*	Management of Voltage levels and Reactive Power at optimal levels to operate the grid more efficiently
IVVC	*Integrated Volt-VAR Control*	Full coordination and configuration of intelligent field devices and a management/control system (e.g., DMS, DSCADA) that uses grid data to achieve efficient grid operation while maintaining distribution voltages within acceptable operating limits
DMS	*Distribution Management System*	Primary information system used to monitor, analyze, and control the distribution grid efficiently and reliably
DSDR	*Distribution System Demand Response*	Operational mode of VVO that supports peak shaving and emergency MW *(demand)* reduction (alternative to building peaking plant generation)
CVR	*Conservation Voltage Reduction*	Operational mode of VVO that supports 24/7 voltage reduction and energy conservation (alternative to building base load generation)

DEC VOLT VAR CONTROL



Corrected 11.06.2020

"HIGH LEVEL" CONCEPTUAL DESIGN



- DSM & SCADE already exists and is not in scope of this project.
- Devices will be integrated into the existing DMS/SCADA

RENEWABLE ENERGY STRATEGY / FORECAST

Corrected 11.06.2020

APPENDIX E: RENEWABLE ENERGY STRATEGY/FORECAST

The growth of renewable generation in the United States continued in 2019. According to EIA, in 2019, 9.1 GW of wind and 5.3 GW of utility-scale solar capacity were installed nationwide. The EIA also estimates 3.7 GW of small scale solar was added as well.[1] Notably, U.S. annual energy consumption from renewable sources exceeded coal consumption for the first time since before 1885.[2]

North Carolina ranked sixth in the country in solar capacity added,and first in additions of solar plants greater than 2 MW, in 2019 and remains second behind only California in total solar capacity online, while South Carolina ranked seventh in solar capacity added in 2019.[3][4] Duke Energy's compliance with the North Carolina Renewable Energy and Energy Efficiency Portfolio Standards (NC REPS), the South Carolina Distributed Energy Resource Program (SC DER or SC Act 236), the Public Utility Regulatory Policies Act (PURPA) as well as the availability of the Federal Investment Tax Credit (ITC) were key factors behind the high investment in solar.

RENEWABLE ENERGY OUTLOOK FOR DUKE ENERGY IN THE CAROLINAS

The future is bright for opportunities for continued renewable energy development in the Carolinas as both states have supportive policy frameworks and above average renewable resource availability, particularly for solar. The Carolinas also benefits from substantial local expertise in developing and interconnecting large scale solar projects and the region will benefit from such a concentration of skilled workers. Both states are supporting future renewable energy development via two landmark pieces of legislation, HB 589 in North Carolina (2017) and Act 62 in South Carolina (2019). These provide opportunities for increased renewable energy, particularly for utility customer programs for both large and small customers who want renewable energy. These programs have the potential to add significant renewable capacity that will be additive to the historic reliance on administratively-established standard offer procurement under PURPA in the Carolinas. Furthermore, the Companies'

[1] All renewable energy GW/MW represent GW/MW-AC (alternating current) unless otherwise noted.
[2] https://www.eia.gov/todayinenergy/detail.php?id=43895.
[3] https://www.seia.org/states-map.
[4] https://www.eia.gov/electricity/data/eia860M/; February month end data.

pending request to implement Queue Reform—a transition from a serial study interconnection process to a cluster study process—will create a more efficient and predictable path to interconnection for viable projects, including those that are identified through any current or future procurement structures. It is also worth noting that that there are solar projects that appear to be moving forward with 5-year administratively-established fixed price PURPA contracts and additional solar projects that will likely be completed as part of the transition under Queue Reform.

SUMMARY OF EXPECTED RENEWABLE RESOURCE CAPACITY ADDITIONS

DRIVERS FOR INCREASING RENEWABLES IN DEC

The implementation of NC HB 589, and the passage of SC Act 62 in SC are significant to the amount of solar projected to be operational during the planning horizon. Growing customer demand, the Federal ITC, and declining installed solar costs continue to make solar capacity the Company's primary renewable energy resource in the 2020 IRP. However, achieving the Company's goal of net-zero carbon emissions by 2050 will require a diverse mix of renewable, and other zero-emitting, load following resources. Wind generation, whether onshore wind generated in the Carolinas or wheeled in from other regions of the country, or offshore wind generated off the coast of the Carolinas, may become a viable contributor to the Company's resource mix over the planning horizon.

The following key input assumptions regarding renewable energy were included in the 2020 IRP:

- Through existing legislation such as NC HB589 and opportunities under SC Act 62, along with materialization of existing projects in the distribution and transmission interconnection queues, installed solar capacity increases in DEC from 966 MW in 2021 to 3,493 MW in 2035 with approximately 185 MW of usable AC storage coupled with solar included prior to incremental solar added economically during the planning process.

- Additional solar and solar coupled with storage was available to be selected by the capacity expansion model to provide economic energy and capacity. Consistent with recent trends, total annual solar and solar coupled with storage interconnections were limited to 300 MW per year over the planning horizon in DEC.

- Up to 150 MW of onshore Carolinas wind generation, assumed to be located in the central Carolinas, could be selected by the capacity expansion model annually to provide a diverse source of economic energy and capacity.

- Compliance with NC REPS continues to be met through a combination of solar, other renewables, EE, and Renewable Energy Certificate (REC) purchases.

- Achievement of the SC Act 236 goal of 160 MW of solar capacity located in DEC.

- Implementation of NC HB 589 and SC Act 62 and continuing solar cost declines drive solar capacity growth above and beyond NC REPS requirements.

NC HB 589 COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY (CPRE)

NC HB 589 established a competitive solicitation process, known as the Competitive Procurement of Renewable Energy (CPRE), which specified for the addition of up to 2,660 MW of competitively procured renewable resources across the Duke Energy Balancing Authority Areas over a 45-month period ending November 2021. On July 10, 2018, Duke issued a request for bids for the first tranche of CPRE, requesting 600 MW in DEC and 80 MW in DEP. On April 9, 2019 the independent administrator selected 12 projects totaling 515 MW in DEC and two projects totaling 83 MW in DEP. Eleven of the DEC projects totaling 465 MW signed PPA's, but subsequently, one project dropped out and will not move forward, bringing the total capacity procured to 435 MW. Nine of the projects will be located within North Carolina (415 MW), one will be in South Carolina (20 MW), and the projects will all be interconnected to the transmission system. Two of the solar projects selected will be owned by Duke Energy Carolinas and three by Duke Energy Renewables. Two of the third-party projects selected include battery storage. See the annual CPRE Program Plan included as Attachment II for additional details.

CPRE tranche 2 requested bids for 600 MW in DEC and 80 MW in DEP. The bid window closed March 9, 2020. Initial statistics showed DEC received 37 bids for approximately 1,850 MW. Twenty of the bids, representing approximately 1,050 MW were located within NC and the remaining 17 bids and 800 MW were located within SC. Three proposals were submitted with energy storage. Each of the 37 projects requested transmission interconnection.

The finalists were selected from the initial bid list, and eleven projects were chosen for DEC with a combined capacity of 615 MW. Ten of the projects representing 540 MW are located in NC and one project at 75 MW is located in SC. There were no projects with energy storage selected.

All of the projects plan to employ a single axis tracking configuration. The weighted average price decrement for these proposals is approximately $4.90/MWh. No projects have executed contracts yet, and the contract negotiation window will close October 15, 2020.

The volume of any future tranches of CPRE will depend on the final results of tranche 2, as well as, the continued increases in capacity referred to in this document as the “Transition MW”. These “Transition MW” represent the total capacity of renewable generation projects in the combined Duke Balancing Authority area that are (1) already connected; or (2) have entered into purchase power agreements (PPAs) and interconnection agreements (IAs) as of the end of the 45-month competitive procurement period, and which are not subject to curtailment or economic dispatch. The total CPRE target of 2,660 MW will vary based on the amount of Transition MW at the end of the 45-month period, which NC HB 589 expected to total 3,500 MW. If the aggregate capacity in the Transition MW exceeds 3,500 MW, the competitive procurement volume of 2,660 MW will be reduced by the excess amount and vice versa. As of May 2020, there is approximately 4,020 MW of solar capacity and 280 MW of non-solar capacity that meet NC HB 589’s definition of “Transition MW”, meaning CPRE will be reduced by a minimum of 800 MW. The company believes the Transition may ultimately exceed 3,500 MW by as much as 1,850 MW, and possibly more depending on the extent to which SC Act 62 and Interconnection Queue reform drive new solar growth in SC by the end of the 45-month CPRE period.

NC AND SC INTERCONNECTION QUEUES

Through the end of 2019, DEC had more than 750 MW of utility scale solar on its system, with approximately 30 MW interconnecting in 2019. When renewable resources were evaluated for the 2020 IRP, DEC reported approximately 160 MW of third-party solar construction in progress and approximately 5,000 MW in the interconnection queue. Details of the number of pending projects and pending capacity by state are included in Appendix K.

Projecting future solar connections from the interconnection queue presents a significant challenge due to the large number of project cancellations, ownership transfers, interconnection studies required, and the unknown outcome of which projects will be selected through the CPRE program. Additionally, any future efforts to reform the transmission or distribution interconnection queues could cause these projections to vary.

DEC's contribution to the Transition depends on many variables including connecting projects under construction, the expected number of renewable projects in the queue with a PPA and IA, SC Act 62, and SC DER Program Tier I. As of May 31, 2020, DEC had nearly 250 MW of solar capacity with a PPA and IA, and roughly 140 MW of non-solar renewable capacity with PPAs that extend through the 45-month CPRE period. A number of additional projects in the queue are expected to acquire both a PPA and IA prior to the expiration of the 45-month period defined in NC HB 589, potentially resulting in approximately an additional 300 MW contributing to the Transition. In total, DEC may contribute roughly one-quarter of the Transition MW with DEP accounting for the remaining three-quarters.

NC REPS COMPLIANCE

DEC remains committed to meeting the requirements of NC REPS, including the solar, poultry waste, and swine waste set-asides, and the general requirement, defined as the total REPS requirement net of the three set-asides, which will be met with additional renewable and energy efficiency resources. DEC's long-term general compliance needs are expected to be met through a combination of renewable resources, including RECs obtained through the NC HB 589 competitive procurement process. For details of DEC's NC REPS compliance plan, please reference the NC REPS Compliance Plan, included as Attachment I to this IRP.

NC HB-589 COMPETITIVE PROCUREMENT AND UTILITY-OWNED SOLAR

DEC continues to evaluate utility-owned solar additions to grow its renewables portfolio. For example, DEC owns and operates three utility-scale solar projects, totaling 76 MW-AC, as part of its efforts to encourage emission free generation resources and help meet its compliance targets:

- Monroe Solar Facility – 55 MW, located in Union County, North Carolina placed in service on March 29, 2017

- Mocksville Solar Facility – 15 MW, located in Davie County, North Carolina placed in service on December 16, 2016
- Woodleaf Solar Facility – 6 MW, located in Rowan County, North Carolina placed in service on December 21, 2018

No more than 30% of the CPRE Program requirement may be satisfied through projects in which Duke Energy or its affiliates have an ownership interest at the time of bidding. DEC and Duke Energy Renewables were each awarded approximately 20% of the capacity selected in the first tranche of CPRE. NC HB 589 does not stipulate a limit for DEC's option to acquire projects from third parties that are specifically proposed in the CPRE Request for Proposals (RFP) as acquisition projects, though any such project will not be procured unless determined to be among the most cost-effective projects submitted.

ADDITIONAL FACTORS IMPACTING FUTURE SOLAR GROWTH

According to BloombergNEF and the Solar Energy Industries Association (SEIA), the solar industry has not been immune to the impacts of COVID-19.[5] [6] The industry has experienced a significant loss in employment in the United States with most of the job losses and impacts associated with distributed generation. The pandemic has certainly introduced supply chain risks, and anecdotal evidence suggests that project financing is becoming more challenging, especially with the likely contraction of tax equity markets. Offsetting these concerns is a more diversified supply chain, especially in the United States, which helps to mitigate some of the supply chain risks. In addition, the U.S. Congress has passed several bills to help provide stimulus and liquidity in the markets, and there are various infrastructure legislative proposals that contain incentives to help the solar industry to continue to move forward. Taken together, the prevailing consensus seems to be that utility scale projects may be delayed, but it is unlikely that there will be large scale cancellations.

Beyond the immediate COVID-19 concerns, there are numerous other factors that impact the Company's forecast of future solar growth in the Carolinas. Key among these is potential changes in the Company's avoided cost in either NC or SC, as these may impact the development of projects under

[5] https://www.powerengineeringint.com/renewables/bnef-predicts-slow-down-in-clean-energy-economy-due-to-covid-19/.
[6] https://www.seia.org/sites/default/files/2020-05/SEIA-COVID-Impacts-National-Factsheet.pdf.

PURPA, NC HB 589, and SC Act 62. Avoided cost forecasts are subject to variability due to changes in factors such as natural gas and coal commodity prices, system energy and demand requirements, the level and cost of generation ancillary service requirements, and interconnection costs. PURPA requires utilities to purchase power from QFs at or below the utility's avoided cost rates. NC HB 589 requires that competitive bids are priced below utility's avoided cost rates, as approved by the NCUC, in order to be selected. Given the potential for changes in the avoided cost rates, the installed cost of solar remains a critical input for forecasting how much solar will materialize in the future. This stems from the fact that the actual cost of solar is not related to the PURPA avoided cost rates, even though solar investment was possible in the past at those avoided cost rates.

Installed solar costs encompass many variables, including physical components such as PV modules, inverters, electrical, and structural equipment, as well as engineering design, O&M and interconnection charges, to name a few. Solar panel prices have been declining at a fairly significant rate during the past decade and are expected to continue this decline into the future, although the Section 201 tariffs that were enacted in 2018 will continue to impact module costs at least through 2021. The tariff is related to solar modules and cells and is set at 20% for the remainder of 2020 and dropping to 15% in 2021, which would be the last year the tariffs are in effect. Additional factors that could put upward pressure on solar costs include direct interconnection costs, as well as costs incurred to maintain the appropriate operational control of the facilities. Finally, as panel prices have decreased, there has been more interest in installing single-axis tracking (SAT) systems (as demonstrated in CPRE tranches 1 and 2) and/or systems with higher inverter load ratios (ILR) which change the hourly profile of solar output and increase expected capacity factors. DEC models fixed tilt and SAT system hourly profiles with a range of ILRs as high as 1.6 (DC/AC ratio).

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

NC HB 589 CUSTOMER PROGRAMS

In addition to the CPRE program, NC HB 589 offers direct renewable energy procurement for major military installations, public universities, and other large customers, as well as a community solar program. These programs are in addition to the existing SC Act 236 Programs and upcoming SC Act 62 programs.

As part of NC HB 589, the renewable energy procurement program enables large customers to procure renewable energy attributes from new renewable energy resources and receive a bill credit for the energy and capacity provided to DEC's system. The program allows for up to 600 MW of total capacity, with set asides for military installations (100 MW of the 600 MW) and the University of North Carolina (UNC) system (250 MW of the 600 MW). The 2020 IRP base case assumes all 600 MW of this program materialize, with the DEC/DEP split expected to be roughly 65/35. If all 600 MW are not utilized, the remainder will roll back to the competitive procurement, increasing its volume.

The community solar portion of NC HB 589 calls for up to 20 MW of shared solar in DEC. This program is similar to the SC Act 236 Shared Solar program in that it allows customers who cannot or do not want to put solar on their property to take advantage of the economic and environmental benefits of solar by subscribing to the output of a centralized facility. A key difference between the SC Act 236 Shared Solar program and the NC HB 589 Shared Solar program is that HB 589 does not allow the program to be subsidized. Customers must be credited at avoided cost and projects cannot be greater than 5MW. An RFP issued in 2019 with these parameters resulted in no bids. The 2020 IRP Base Cases assume that all 20 MW of the NC HB 589 shared solar program materializes starting in 2022.

NC HB 589 also established a rebate program for rooftop solar, limited to 10 MW of installed capacity per utility per year over 2018 through 2022. There are rules governing residential and non-residential customers, along with set asides for nonprofit organizations. Any set asides not used by year end 2022 will be reallocated for use by any customer type who meets the necessary qualifications. Since its inception in 2018, the rebate program has spurred greater interest in solar installations and therefore, more net metered customers in NC. Residential and non-residential capacity limits were quickly fully subscribed in 2018, 2019 and 2020. DEC NC installed approximately 13 MW of rooftop solar in 2018 and approximately 23 MW of rooftop solar in 2019. Through May of 2020, installed rooftop solar capacity is approximately 11 MW. For further discussion of rooftop solar projections, see below, as well as, Appendix C.

SC ACT 236 AND SC ACT 62

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

- **Tier I:** 40 MW of solar capacity from facilities each >1 MW and ≤ 10 MW in size connected to the distribution system.

- **Tier II:** 40 MW of behind-the-meter solar facilities for residential, commercial and industrial customers, each ≤1 MW, 25% of which must be ≤ 20 kilowatts (kW). Since Tier II is behind the meter, the expected solar generation is embedded in the load forecast as a reduction to expected load.

- **Tier III:** Investment by the utility in 40 MW of solar capacity from facilities each >1 MW and ≤10 MW in size connected to the distribution system. Upon completion of Tiers I and II (to occur no later than 2021), the Company may directly invest in additional solar generation to complete Tier III.

DEC has executed twelve PPAs totaling approximately 38 MW and is working to complete Tier I. Tier II incentives have resulted in growth in rooftop solar in DEC, which now has over 80 MW of rooftop solar installed. The 2% net metering application cap of 80 MW established in Act 236 was reached in DEC SC but has since been eliminated by SC Act 62.

The Company launched its first Shared Solar program in DEC as part of Tier I in the first quarter of 2019. Duke Energy designed its initial SC shared solar program to have strong appeal to residential and commercial customers who rent or lease their premises, residential customers who reside in multifamily housing units or shaded housing or for whom the relatively high up-front costs of solar PV make net metering unattainable, and non-profits who cannot monetize the ITC. To make the program financially feasible, subscription fees are subsidized by the ratebase. The program capacity is 3 MW including 400 kW set aside for low to moderate income (LMI) customers earning less than 200% of the federal poverty level. The unreserved 2,600 kW of capacity sold out within 3 months due to the program's strong economic proposition. As of the end of June 2020, the low to moderate income carve-out is fully subscribed as well.

TABLE E-1

DEC SHARED SOLAR PROGRAM

	AVERAGE SUBSCRIPTION KW PER PARTICIPANT	CUSTOMERS	CAPACITY (KW)
Residential LMI	2	200	400
Residential Non-LMI	5.01	271	2600
Non-Residential	124.3	10	

SC Act 62 passed in South Carolina on May 16, 2019. SC Act 62 will likely drive additional PURPA solar as DEC must offer fixed price PPAs to certain small power producers at avoided cost for a minimum contract term of 10 years. The 10-year rate is applicable for projects located in SC until DEC has executed IAs and PPAs with aggregated nameplate capacity equal to 20 percent of the previous 5-year average of DEC's SC retail peak load, or roughly 800 MW. After 800 MW have executed IAs and PPAs the Commission will determine conditions, rates, and terms of length for future contracts. Given there is roughly 2,700 MW of solar pending in DEC SC, the Company expects to meet 800 MW within the IRP planning period. The Company intends to closely monitor the capacity with executed IAs and PPAs, evaluate impacts on the NC HB 589 Transition MW and corresponding reduction in CPRE volume. Once the 800 MW threshold is reached, the SC PSC will determine the term limit for PURPA contracts in its sole discretion.

SC Act 62 also called for additional customer programs, requiring the utilities to file voluntary renewable energy programs within 120 days of SC Act 62 passing, and encouraging additional community solar. The Company has a proposed voluntary renewable energy program pending before the Commission, which would create a 150 MW program for DEC and DEP SC combined (113 MW in DEC) offering up to 20-year PPAs. The Companies are considering whether additional community solar should be pursued.

Finally, SC Act 62 lifted the cap on net metering, requiring the Company to offer full retail rate net metering through June 1, 2021, as approved through proceedings under Act 236. As required by the legislation, the Public Service Commission of South Carolina opened a docket in May 2019 to establish a solar choice metering tariff to go into effect for customer applications received after May 31, 2021 which would replace the meting tariff for new installations.[7] The Company expects net metering adoption to pick up to comparable levels of adoption observed in DEC-SC in 2017/2018 through June 2021. Future adoption after that date will be determined based upon the solar choice tariff terms approved by the SC PSC.

WIND

DEC considers wind a potential energy resource in the short and long term to support increased renewable portfolio diversity, an important resource for achieving the Company's 2050 net-zero carbon emission goal, as well as long-term general compliance need. However, sourcing wind remains challenging, whether the wind is imported from other states, sited within the Carolinas, or sited offshore.

In 2020, offshore wind energy is becoming a more viable alternative, but only one project near the Carolinas, the Avangrid Kitty Hawk project off the coast of North Carolina, has the necessary Bureau of Ocean Energy Management ("BOEM") offshore lease to begin construction. Several call areas began the process of evaluation along the North and South Carolina border but stalled out in recent years as BOEM refocused their efforts to areas with higher demand. These call areas could eventually become new leasing areas, but first BOEM's Task Force will need a representative from South Carolina to restart the permitting and approvals process.

The Company continues to evaluate options for increasing access to offshore wind energy into the Carolinas, however the cost to transport wind energy from the coast to the load centers located in central North Carolina and South Carolina is significant. In 2012, the North Carolina Transmission Planning Collaborative ("NCTPC") released a study that estimated transmission upgrade costs for moving wind into the Carolinas in a few different scenarios: the costs ranged from approximately $930M to $1,730M. While the Company continues working with the NCTPC to update estimates for integrating offshore wind into the DEP and DEC territories, the Company expects those costs to increase significantly as the costs to site and build new transmission infrastructure has increased over

[7] PSCSC Docket 2019-182E.

the last decade. For further discussion of the transmission costs associated with moving offshore wind from the coast to load centers in the Carolinas, see Chapter 7.

Wind energy generated onshore in the Carolinas presents other challenges. The wind capacity (speeds and duration) are generally best in the mountains and along the coast of the Carolinas, but these locations also have hurdles. While the moratorium on building land-based wind in NC has recently expired, the Mountain Ridge Protection Act prevents building wind on ridgetops, and coastal tourism often deters siting on land along the coast. Aside from the policy barriers, there is a significant need for meteorological towers to collect wind speed history in key areas across the Carolinas to gain confidence in predicted capacity factors. The Carolinas onshore wind profiles used in this IRP were provided by a third party and may not be based on wind speeds measured near the expected hub heights.

While the Company is working to improve the quality of Carolinas onshore wind profiles for use in future IRPs it is expected that wind generation located in the central portion of the Carolinas would generally have much lower output than sites located on the coast or mountains, but the benefit of these sites would likely be lower transmission costs. These lower costs could potentially outweigh effects of lower output, particularly since their wind profiles are generally complementary to solar generation.

On-shore wind located outside of the Carolinas presents both economic and logistical challenges associated with constructing significant transmission infrastructure. In August 2017, DEC issued an RFP for delivered energy, capacity, and associated RECs from wind projects up to 500 MW. While bids received were not economically valuable enough to pursue, the Company has continued to evaluate potential projects. Out-of-state transmission costs and availability are one of the complicating factors for importing wind from out of state.

While wind energy continues to face challenges, the Company believes wind energy can become a viable resource by the end of the planning horizon. For this reason, Central Carolinas wind was included as an available resource in the base case, and the high renewable case includes both offshore and central US located wind as resources in the 2030 to 2035 timeframe. Additionally, the Company included higher levels of offshore wind in the 70% CO_2 Reduction: High Wind portfolio to demonstrate how diversifying the Company's resource mix can help achieve aggressive carbon emission reduction goals. The No New Gas Generatio portfolio also included offshore wind but the majority was serving DEP demand. It is possible that future policy may provide for cost and benefit sharing of emerging carbon free resources, such as offshore wind, across all customers in both utilities in order to equitably advance such technologies. For a more detailed summary of these portfolios, see Chapter 12 and Appendix A.

SUMMARY OF EXPECTED RENEWABLE RESOURCE CAPACITY ADDITIONS

BASE WITH CARBON POLICY

The 2020 IRP Base with Carbon Policy case incorporates the projected and economically selected renewable capacities shown below. This case includes renewable capacity components of the Transition MW, such as capacity required for compliance with NC REPS, PURPA purchases, the SC DER Program, NC Green Source Rider (pre HB 589 program), and the additional three components of NC HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). The Base Case also includes additional projected solar growth beyond NC HB 589, including expected growth from SC Act 62 and the materialization of additional projects in the transmission and distribution queues. The Base Case does not attempt to project future regulatory requirements for additional solar generation, such as new competitive procurement offerings after the current CPRE program expires.

However, it is the Company's belief that continued declines in the installation cost of solar and storage will enable solar and coupled "solar plus storage" systems to contribute to energy and/or capacity needs. Additionally, the inclusion of a CO_2 emissions tax, or some other carbon emissions reduction policy, would further incentivize expansion of solar resources in the Carolinas. In the 2020 IRP, the capacity expansion model selected additional solar averaging approximately 100 MW per year beginning in 2025 and solar coupled with storage averaging approximately 120 MW annually beginning in 2028 if a CO_2 tax were implemented in the 2025 timeframe.

Unlike the first tranche of CPRE, the second tranche of CPRE did not yield any solar plus storage projects. The Company continues to believe that the combination of falling storage costs in addition to the most recent avoided cost rate structures proposed in both NC and SC provide strong price incentives for QFs to shift energy from lower priced energy-only hours to hours that have higher energy and capacity prices. This rate design provides incentives to encourage storage additions to solar projects. The Company this year is also projecting that a significant amount of incremental solar beyond NC HB 589 will be coupled with storage. The 2020 base case assumes storage is DC coupled with solar, has a four-hour duration, and the capacity of the battery storage is 25% of the capacity of the solar. In total, DEC expects approximately 1,525 MW of solar coupled with approximately 380 MW of storage by the end of 2035.

Additionally, Phase 1 of NREL's Integration of Carbon Free Resources Study, highlighted the benefit storage provides by reducing the curtailment of solar resources as significant levels of solar are added to the DEC system and create more excess energy conditions. At current levels of solar investment in DEC, curtailment is not a significant concern in the short-term due to the availability of pumped hydro storage resources. However, curtailment may become more prevalent towards the end of the planning horizon as solar investment is expected to expand in DEC.

Finally, as solar generation is expected to continue its expansion in DEC, interconnecting several thousand MW of new solar generation will likely require new transmission projects and could create logistical constraints due to limited transmission outage windows as these projects are implemented. For the last five years, DEC and DEP have interconnected approximately 500 MW of solar combined annually. While interconnections may potentially exceed those levels in the short-term, over the planning horizon, for base case planning purposes, the Company assumed interconnections were limited to 500 MW on an annual average basis. Since the majority of growth is expected in DEC, the DEC specific interconnection constraint was assumed to be 300 MW annually. The Company will continue to monitor interconnections, and should new, larger projects request interconnection to the DEC system or other efficiencies be realized, the level of interconnections may increase.

The Company anticipates a diverse renewable portfolio including solar, biomass, hydro, storage fed by solar, wind, and other resources. Actual results could vary substantially for the reasons discussed previously, as well as, other potential changes to legislative requirements, tax policies, technology costs, carbon prices, ancillary costs, interconnection costs, and other market forces. The details of the forecasted capacity additions, including both nameplate and contribution to winter and summer peaks are summarized in Table E-2 below.

TABLE E-2

DEC BASE WITH CARBON POLICY TOTAL RENEWABLES

DEC BASE RENEWABLES - COMPLIANCE + NON-COMPLIANCE															
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL
2021	966	0	132	0	1,099	387	0	132	0	519	10	0	132	0	142
2022	1,327	115	118	0	1,560	514	70	118	0	702	13	29	118	0	160
2023	1,673	134	81	0	1,888	636	81	81	0	797	17	34	81	0	131
2024	1,976	163	81	0	2,219	741	99	81	0	921	20	41	81	0	141
2025	2,268	192	59	0	2,519	844	116	59	0	1,019	23	48	59	0	129
2026	2,519	211	49	0	2,778	930	127	49	0	1,106	25	53	49	0	127
2027	2,708	335	49	0	3,091	977	202	49	0	1,228	27	84	49	0	160
2028	2,895	458	42	0	3,395	1,024	274	42	0	1,340	29	114	42	0	185
2029	3,082	656	42	0	3,779	1,071	390	42	0	1,502	31	164	42	0	236
2030	3,217	802	38	0	4,058	1,104	475	38	0	1,618	32	201	38	0	271
2031	3,352	948	30	0	4,330	1,138	559	30	0	1,727	34	237	30	0	301
2032	3,486	1,094	12	0	4,592	1,171	642	12	0	1,826	35	273	12	0	321
2033	3,620	1,238	3	0	4,861	1,205	724	3	0	1,932	36	310	3	0	349
2034	3,753	1,382	0	0	5,135	1,230	803	0	0	2,032	37	345	0	0	383
2035	3,885	1,525	0	150	5,560	1,242	875	0	11	2,127	38	381	0	50	469

Data presented on a year beginning basis.
Solar includes 0.5% per year degradation.
Capacity listed excludes REC Only Contracts.
Solar contribution to peak based on 2018 Astrapé analysis; solar with storage contribution to peak based on 2020 Astrapé ELLC study.

While solar is not at its maximum output at the time of DEC's expected peak load in the summer, solar's contribution to summer peak load is large enough that it will likely push the time of summer peak to a later hour if solar generation levels continue to increase. However, solar is unlikely to have a similar impact on the morning winter peak due to little solar output in the morning hours. Solar capacity contribution percentages to summer and winter peak demands are assumed to be the same as those used in the 2019 IRP. Note, however the solar contribution to peak values now also include additional contributions provided by storage coupled with solar, assumed to be 100% of the storage capacity installed based on the results of the Capacity Value of Battery Storage study discussed in Appendix H and filed as Attachment IV to this IRP.

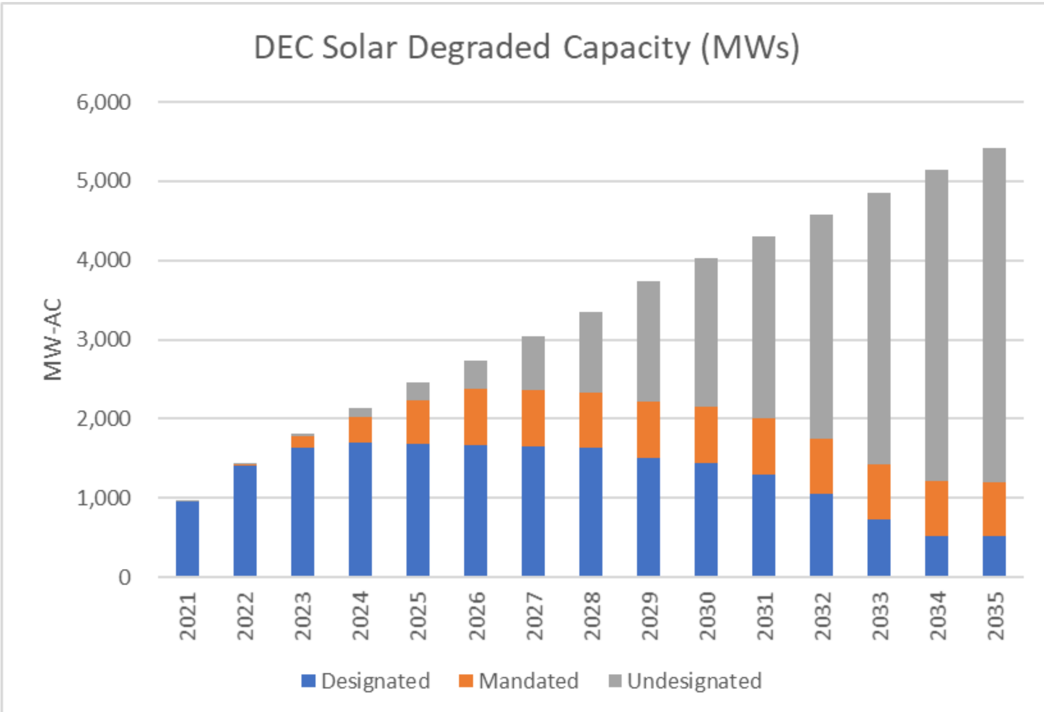
As a number of solar contracts are expected to expire over the IRP planning period, the Company is additionally breaking down its solar forecast into three buckets described below:

- **Designated**: Contracts that are already connected today or those who have yet to connect but have an executed PPA are assumed to be designated for the duration of the purchase power contract.
- **Mandated**: Capacity that is not yet under contract but is required through legislation (examples include future tranches of CPRE, the renewables energy procurement program for large customers, and community solar under NC HB 589 as well as SC Act 236)
- **Undesignated**: Additional capacity projected beyond what is already designated or mandated. Expiring solar contracts are assumed to be replaced in kind with undesignated solar additions. Such additions may include existing facilities or new facilities that enter into contracts that have not yet been executed.

Figure E-1 below shows DEC's breakdown of these three buckets through the planning period. Note for avoided cost purposes, the Company only includes the Designated and Mandated buckets in the base case. For determining the cost cap pricing in the second tranche of CPRE, the Company includes the Designated bucket only.

FIGURE E-1

DEC SOLAR DEGRADED CAPACITY (MW)



HIGH & LOW RENEWABLE CASES

Given the significant volume and uncertainty around solar investment, high and low solar portfolios were compared to the Base Case described above. The portfolios do not envision a specific market condition, but rather the potential combined effect of a number of factors. For example, the high sensitivity could occur given events such as high carbon prices, lower solar capital costs, economical solar plus storage, continuation of renewable subsidies, and/or stronger renewable energy mandates. Additionally, the high case also considers a combination of onshore and offshore wind as viable resources beginning in the 2030 timeframe. On the other hand, the low sensitivity may occur given events such as lower fuel prices for more traditional generation technologies, higher solar installation and interconnection costs, and/or high ancillary costs which may drive down the economic viability of future incremental solar additions. These events may cause solar projections to fall short of the Base Case if the CPRE, renewable energy procurement for large customers, and/or the community solar programs of HB 589 do not materialize or are delayed. Tables E-3 and E-4 below provide the high and low solar nameplate capacity summaries, as well as, their corresponding expected contributions to summer and winter peaks. For more details on these sensitivities see Appendix A.

TABLE E-3

DEC HIGH RENEWABLES SENSITIVITY

DEC HIGH RENEWABLES - COMPLIANCE + NON-COMPLIANCE															
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL
2021	966	0	132	0	1,099	387	0	132	0	519	10	0	132	0	142
2022	1,327	115	118	0	1,560	514	70	118	0	702	13	29	118	0	160
2023	1,673	134	81	0	1,888	636	81	81	0	797	17	34	81	0	131
2024	1,976	163	81	0	2,219	741	99	81	0	921	20	41	81	0	141
2025	2,193	192	59	0	2,444	818	116	59	0	993	22	48	59	0	129
2026	2,369	211	49	0	2,629	879	128	49	0	1,056	24	53	49	0	125
2027	2,737	342	49	0	3,127	984	206	49	0	1,239	27	85	49	0	162
2028	3,103	474	42	0	3,619	1,076	281	42	0	1,398	31	118	42	0	191
2029	3,479	613	42	0	4,134	1,170	358	42	0	1,569	35	153	42	0	230
2030	3,699	750	38	0	4,488	1,225	435	38	0	1,698	37	188	38	0	263
2031	3,925	893	30	90	4,938	1,245	506	30	28	1,810	38	223	30	54	346
2032	4,158	1,117	12	180	5,468	1,266	621	12	57	1,956	39	279	12	109	440
2033	4,406	1,352	3	270	6,031	1,289	736	3	85	2,112	41	338	3	163	545
2034	4,668	1,600	0	360	6,628	1,312	854	0	113	2,279	42	400	0	217	659
2035	4,940	1,856	0	625	7,421	1,337	972	0	160	2,469	43	464	0	336	844

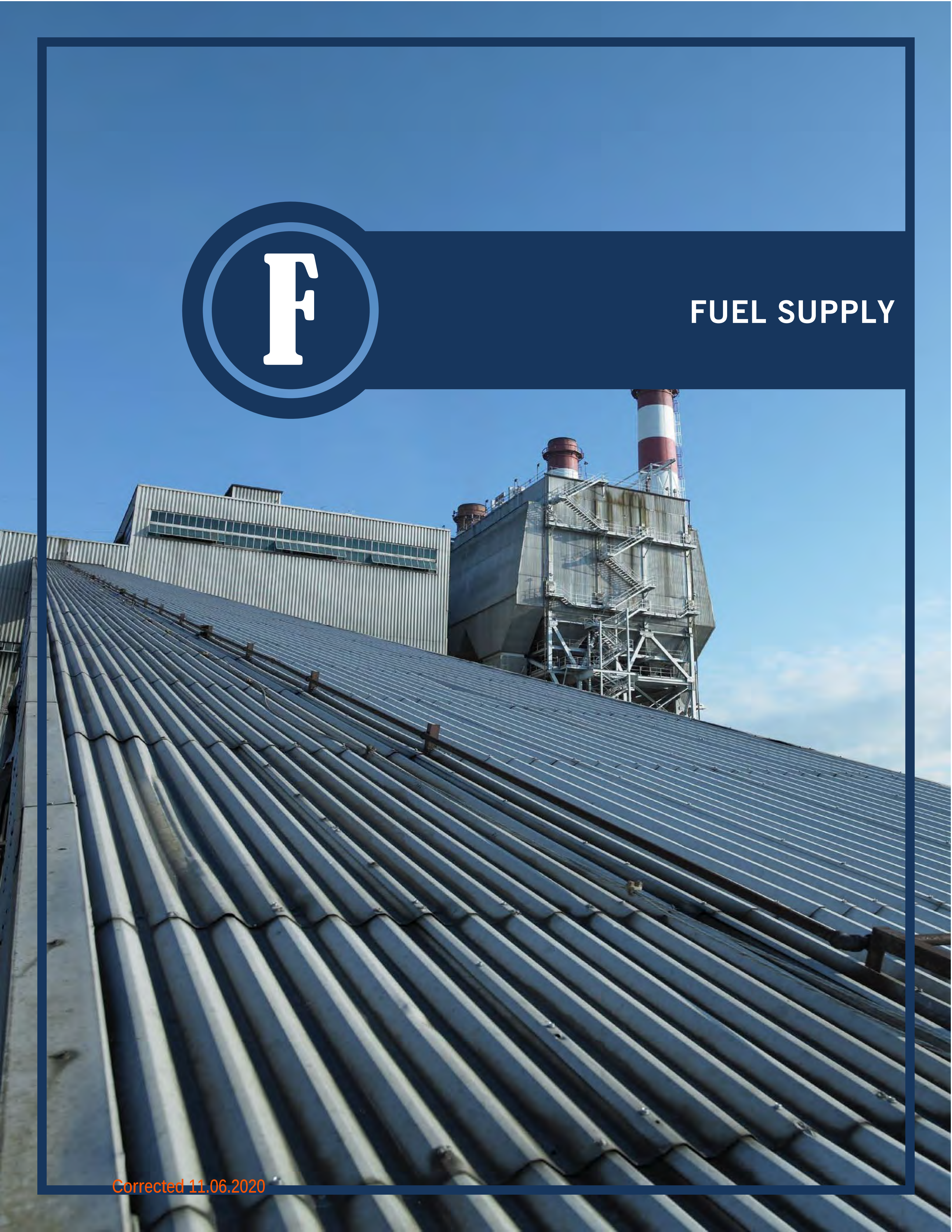
Corrected 11.06.2020

TABLE E-4

DEC LOW RENEWABLES SENSITIVITY

DEC LOW RENEWABLES - COMPLIANCE + NON-COMPLIANCE															
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL
2021	966	0	132	0	1,099	387	0	132	0	519	10	0	132	0	142
2022	1,327	115	118	0	1,560	514	70	118	0	702	13	29	118	0	160
2023	1,673	134	81	0	1,888	636	81	81	0	797	17	34	81	0	131
2024	1,976	163	81	0	2,219	741	99	81	0	921	20	41	81	0	141
2025	2,193	192	59	0	2,444	818	116	59	0	993	22	48	59	0	129
2026	2,369	211	49	0	2,629	879	128	49	0	1,056	24	53	49	0	125
2027	2,584	210	49	0	2,842	946	126	49	0	1,121	26	52	49	0	127
2028	2,797	208	42	0	3,047	999	124	42	0	1,165	28	52	42	0	122
2029	3,009	207	42	0	3,258	1,052	122	42	0	1,216	30	52	42	0	124
2030	3,145	281	38	0	3,465	1,086	166	38	0	1,290	31	70	38	0	140
2031	3,280	355	30	0	3,665	1,120	208	30	0	1,358	33	89	30	0	151
2032	3,414	428	12	0	3,855	1,154	251	12	0	1,417	34	107	12	0	154
2033	3,548	501	3	0	4,052	1,187	292	3	0	1,483	35	125	3	0	164
2034	3,682	574	0	0	4,255	1,220	334	0	0	1,554	37	143	0	0	180
2035	3,815	646	0	0	4,460	1,235	371	0	0	1,607	38	161	0	0	199

Corrected 11.06.2020



FUEL SUPPLY

Corrected 11.06.2020

APPENDIX F: FUEL SUPPLY

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

NATURAL GAS

During 2019 NYMEX Henry Hub natural gas prices averaged approximately $2.51 per million BTU (MMBtu) and U.S. lower-48 net dry production averaged approximately 92 billion cubic feet per day (BCF/day). Natural gas spot prices at the Henry Hub averaged approximately $2.00 per MMBtu in January 2020, while spot pricing decreased throughout the remaining winter months and averaged $1.75 per MMBtu at the end of March 2020. The lower short-term spot prices in February and March 2020 were driven by both fundamental supply and demand factors as winter temperatures remained mild.

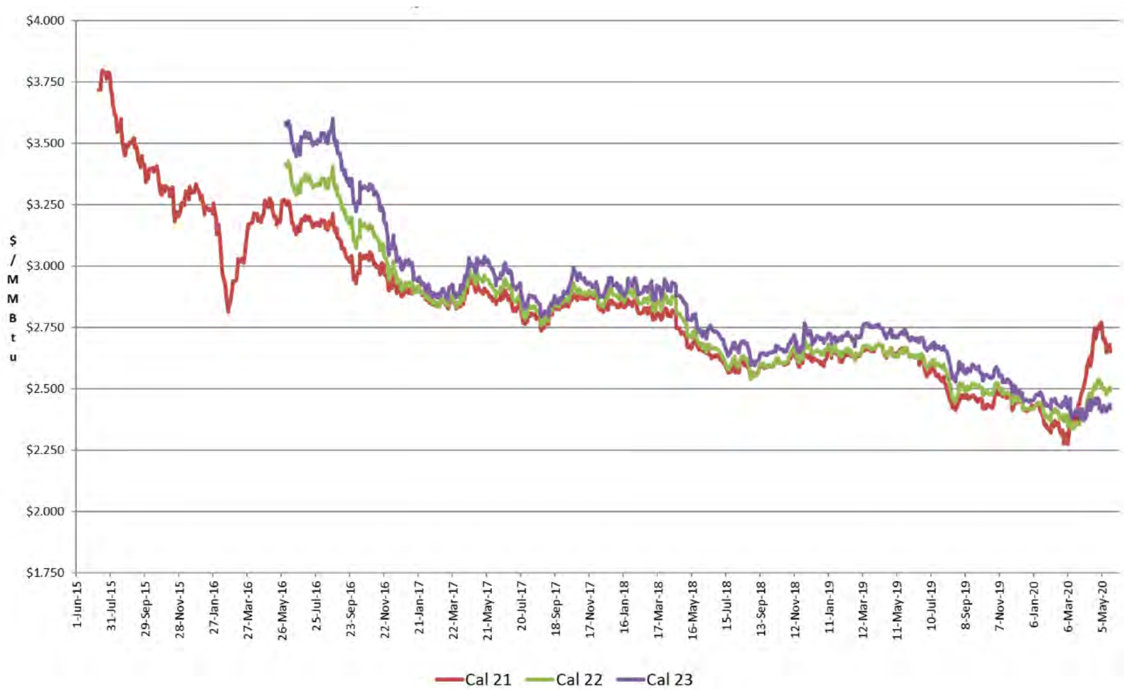
Average daily U.S. net dry production levels of approximately 92 BCF/day in the first quarter of 2020 were 4.2 BCF/day higher than the comparable period in 2019. The EIA is forecasting a decrease this year from a reported 93.1 BCF/day in April, to 85.4 BCF/day by December. Most of this decline in production will be seen in the Appalachian region. Prices are discouraging producers from engaging in natural gas-directed drilling, and in the Permian region, where low oil prices reduce associated gas output from oil-directed wells. Current forecasts show dry natural gas production averaging 84.9 BCF/day in 2021, rising in the second half of the year in response to higher prices.

Following this year's winter withdrawal season, U.S. working gas in storage levels were reported to be at approximately 2.3 trillion cubic feet (TCF) as of April 30, 2020, coming in 20% above the 5-year average between 2015-2019. Lower-48 U.S. overall demand in the first quarter of 2020 was lower than normal due to the above average temperatures throughout the winter months.

While Henry Hub spot prices averaged $1.63 per MMBtu during the first week of June 2020, the EIA forecasts natural gas prices will generally rise through 2020 as a decline in U.S. production is seen. Spot prices at Henry Hub are being forecasted by the EIA to average $2.14 per MMBtu this year, and then increasing to an annual average of $2.89 in 2021 as a result of lower natural gas production.

The EIA is expecting domestic natural gas consumption to see a 3.4 BCF/day decline compared to 2019. Overall U.S. forecasts for the year are down mainly due to reduced economic activity related to COVID-19, led by a decrease in demand during the first quarter as a result of milder-than-normal temperatures. Per the EIA's short-term energy outlook (STEO) released on May 26, 2020, natural gas consumption in the residential and commercial sectors is forecasted to decrease by 3.7% and 6.9%, respectively. Although those two sectors account for a small fraction of U.S. natural gas consumption outside of winter months when heating demand is high, the EIA expects weaker economic conditions in the coming months to further reduce average consumption in the commercial sector. With the weak economic conditions, the EIA also expects industrial natural gas demand to decline in the U.S. from an average of 21.4 BCF/day in 2019, to an average of 19.9 BCF/day in 2020, which will be at its lowest point since the summer of 2016. Following the first half of 2020 short-term energy outlook, which expected natural gas used for electric power to grow 1.6 BCF/day compared to the first half of 2019 as a result of low natural gas prices, and lower-than-expected natural gas capacity additions, the EIA forecasts to see a decline during the second half of 2020. With natural gas prices forecasted to rise during that time, the STEO shows a reduction of natural gas consumption for electric power by 2.2BCF/day compared to the second half of 2019. The EIA's most recent short-term energy outlook also reports an expected rise in the May Henry Hub spot price from $1.88/MMBtu to $2.94/MMBtu by December 2020. These higher natural gas prices will result in some coal-fired generation units to become more economical to dispatch versus natural gas-fired units. EIA expects the share of U.S. total utility-scale electricity generation from natural gas-fired power plants to rise from 37% in 2019 to 39% in 2020. As a result, coal's forecast share of electricity generation falls from 24% in 2019 to 19% in 2020. According to Baker Hughes, as of June 5, 2020, the U.S. rig count was at 284. This is 691 less than this time last year.

FIGURE F-1
HENRY HUB NATURAL GAS PRICE FORWARD CURVE



Looking forward, the forward 5 and 10-year observable market curves are at $2.39 and $2.53 per MMBtu, respectively, as of the June 5, 2020 close. In addition, as of the close of business on June 5, 2020, the one (1), three (3) and five (5) years strips averaged approximately $2.48 per MMBtu. As illustrated with these price levels and relationships, the forward NYMEX Henry Hub price curve is relatively flat with the periods of 2022 and 2023 currently trading at discounts to 2021 prices. The gas market is expected to remain relatively stable due to the recent balancing act of lower production to account for the lack of demand during the COVID-19 pandemic. The North American gas resource picture is a story of unconventional gas production dominating the gas industry. Shale gas now accounts for approximately 97% of net natural gas production today. As noted earlier, per the EIA's short-term outlook dated May 12, 2020, the EIA expects dry gas production to average 89.8 BCF/day by the end of 2020 and fall by 5 BCF/day in 2021 to 84.9 BCF/day. The United States is a net exporter of natural gas, with net exports expected to average 7.3 BCF/day in 2020. According to the EIA forecast, US LNG is forecasted to be 8.9 BCF/day by the end of 2021.

The US power sector still represents the largest area of potential new gas demand, but increased usage is expected to be somewhat volatile as generation dispatch is sensitive to commodity price relationships and growth in renewable generation. Looking forward, economic dispatch competition is expected to continue between gas and coal, although forward natural gas prices have continued to decline and there has been permanent loss in overall coal generation due to the number of coal unit retirements.

In order to ensure adequate natural gas supplies, transportation and storage, the company has gas procurement strategies that include periodic RFPs, market solicitations, and short-term market engagement activities to procure a reliable, flexible, diverse, and competitively priced natural gas supply and transportation portfolio that supports DEC's generation facilities. With respect to storage and transportation needs, the company continues to add incremental firm pipeline capacity and gas storage as the gas generation fleet has grown. The company will continue to evaluate competitive options to meet its growing need for gas pipeline infrastructure as the gas generation fleet grows.

The Atlantic Coast Pipeline (ACP) project was an approximately 600-mile greenfield natural gas pipeline project originating in West Virginia with ultimate delivery into Piedmont's system in Robeson County, North Carolina providing pipeline diversity for the state of NC as well as pipeline diversity for the DEP and DEC electric systems. ACP had an initial capacity of 1.5 BCF/day and would have provided direct upstream access to natural gas production in the Marcellus and Utica shale basins of West Virginia, Pennsylvania and Ohio. On July 5th, 2020 Dominion Energy and Duke Energy announced the cancellation of ACP due to on-going legal uncertainty, anticipated delays and increasing cost uncertainty. DEP and DEC still need additional upstream firm interstate transportation service to support existing and future gas generation in the Carolinas despite the cancellation of the project. Given this change in planned interstate natural gas transportation infrastructure coming into the eastern part of NC, the 2020 IRP no longer includes direct access to interstate Marcellus and Utica shale basins coming into the eastern portions of NC.

To reliably and cost effectively support both the existing natural gas generation fleet and future combined cycle natural gas generation growth the 2020 IRP assumes incremental firm transportation service is obtained, as contemplated in the ACP project, with the exception of coming from alternate pipeline providers. While such incremental firm transportation service may not produce the additional geographic pipeline transportation diversity of the original ACP project it will look to provide needed supply diversity, improve supply reliability and provide greater price stability for customers by reducing reliance on increasingly constrained delivered Transco Zone 5 natural gas supply. In this IRP, firm interstate transportation service is assumed to be procured for any new combined cycle natural gas resource selected in the generation portfolios in this plan along with estimates of the cost of this firm transportation service. The estimated firm transportation service costs were considered in the resource selection process and are included in the financial results presented.

Consistent with past IRPs, the planning process does not assume incremental interstate capacity is procured for additional simple cycle CTs given their low capacity factors. Rather, CTs are assumed to be constructed as dual fuel units that are ultimately connected to Transco Zone 5. Simple cycle CTs will rely on delivered Zone 5 gas supply or, if needed, ultra-low sulfur fuel oil during winter periods where natural gas has limited availability, the pipeline has additional constraints, or if gas is higher priced than the cost to operate on fuel oil. Coal units with gas dual fuel functionality were also not assumed to have firm interstate transportation service. This assumption may be required to change if coal functionality was to be removed from any unit and the unit was solely gas dependent. The Company will continue to refine transportation volume and cost assumptions over time as future developments in interstate delivery options in the Carolinas are more fully known.

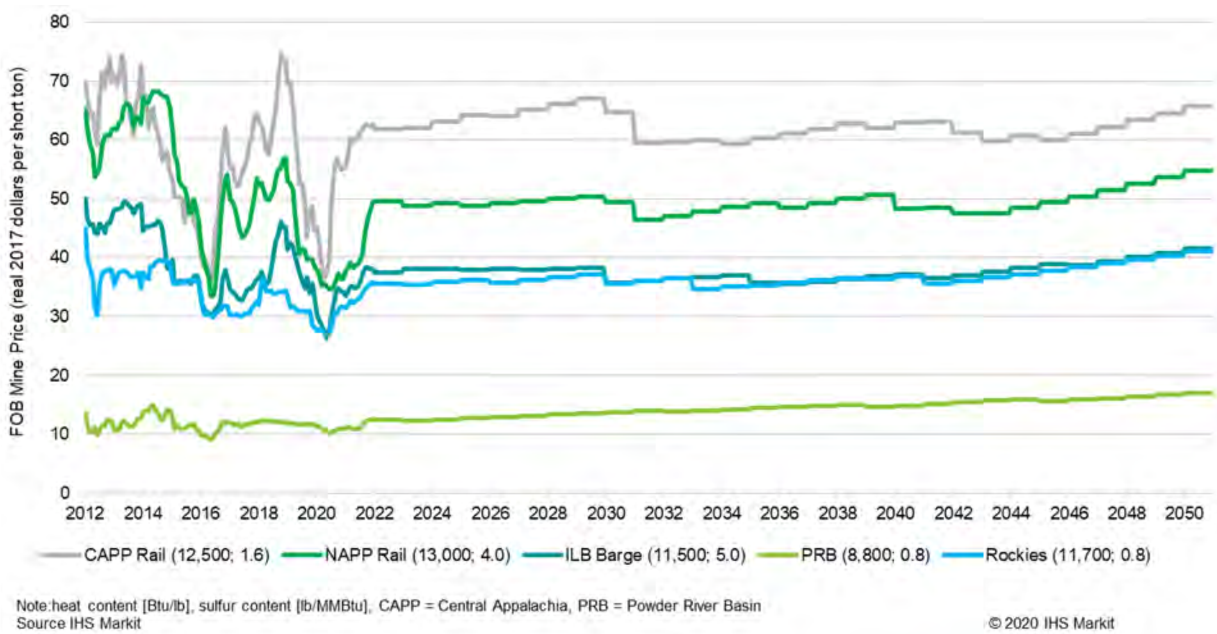
COAL

The main determinants for power sector coal demand are electricity demand growth and non-coal electric generation, namely nuclear, gas, hydro and renewables. With electricity demand growth remaining very low, continued steady nuclear and hydro generation, and increasing gas-fired and renewable generation, coal-fired generation continues to be the marginal fuel experiencing declines. According to the EIA, electric power sector demand has been steadily dropping and accounted for 539 million tons (90%) of total demand for coal in 2019. Additionally, projections show continued strong supply and fluctuating prices for natural gas which, when combined with the addition of new gas-fired combined cycle generating capacity and new projects to enable gas to be co-fired at coal burning stations, continues to result in more volatile coal burns.

Coal markets continue to be distressed and there has been increased market volatility due to a number of factors, including: (1) deteriorated financial health of coal suppliers; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices, which has lowered overall domestic coal demand; (3) uncertainty around proposed, imposed, and stayed U.S. Environmental Protection Agency (EPA) regulations for power plants; (4) changing demand in global markets for both steam and metallurgical coal; (5) uncertainty surrounding regulations for mining operations; (6) tightening supply as bankruptcies, consolidations and company reorganizations have allowed coal suppliers to restructure and settle into new, lower on-going production levels.

According to IHS Markit, future coal prices for the CAPP, NAPP, ILB and PRB coals are expected to be in a steady downward trend through 2020 when they see a modest rebound, flatten and begin to modestly and steadily rise. Future pricing for Rockies coal is expected to steadily rise for the next 20-years.

FIGURE F-2
MINEMOUTH COAL PRICE FORWARD CURVE



With the issuance of the Affordable Clean Energy (ACE) rule in 2019, the fundamental industry outlook now anticipates that less efficient higher cost coal unit retirements will accelerate, with only the lowest-cost production surviving long term. IHS Markit expects 80 GW of coal plant retirements from 2020 to 2025, followed by 42 GW from 2026 to 2030, and 68 GW from 2031 to 2050.

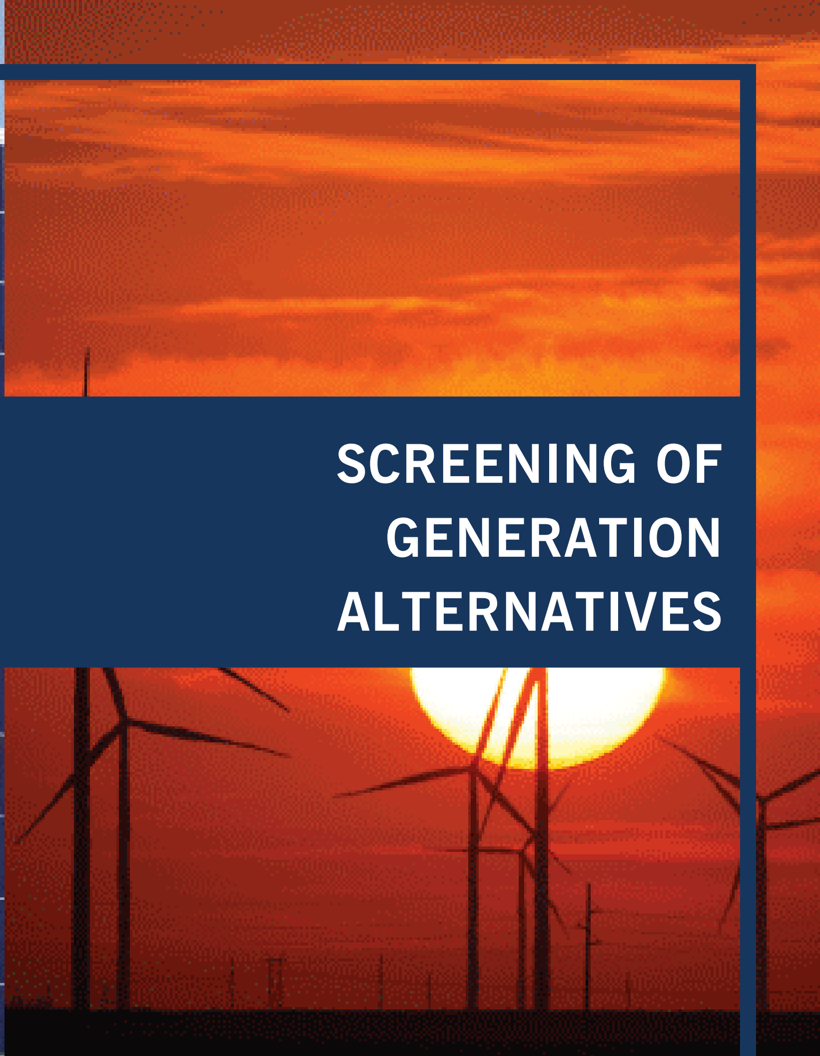
Coal exports have not been immune to global market pressures as total coal exports declined 20% in 2019 from historically high levels in 2018. IHS Markit expects US exports to be curtailed in the short term due to the economic impacts of COVID-19, but projects that exports, especially for metallurgical coal, should stabilize over the long-term horizon. Lower cost thermal export demand is projected to be mostly limited to NAPP and ILB longwall operations, while higher cost production mines are expected to struggle during weaker market years.

The Company continues to maintain a comprehensive coal procurement strategy that has proven successful over the years in limiting average annual fuel price changes while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost-effective manner. Aspects of this procurement strategy include having an appropriate mix of contract and spot purchases for coal, staggering coal contract expirations which thereby limit exposure to market price changes, diversifying coal sourcing as economics warrant, as well as working with coal suppliers to incorporate additional flexibility into their supply contracts.

NUCLEAR FUEL

Requirements for uranium concentrates, conversion services and enrichment services are primarily met through a portfolio of long-term supply contracts. The contracts are diversified by supplier, country of origin and pricing. In addition, DEC staggers its contracting so that its portfolio of long-term contracts covers the majority of fleet fuel requirements in the near-term and decreasing portions of the fuel requirements over time thereafter. By staggering long-term contracts over time, the Company's purchase price for deliveries within a given year consists of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. Diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Near-term requirements not met by long-term supply contracts have been and are expected to be fulfilled with spot market purchases.

Due to the technical complexities of changing suppliers of fuel fabrication services, DEC generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts. As fuel with a low-cost basis is used and lower-priced legacy contracts are replaced with contracts at higher market prices, nuclear fuel expense is expected to increase in the future. Although the costs of certain components of nuclear fuel are expected to increase in future years, nuclear generation costs are expected to be competitive with alternate generation and customers will continue to benefit from the Company's diverse generation mix.



G

SCREENING OF GENERATION ALTERNATIVES

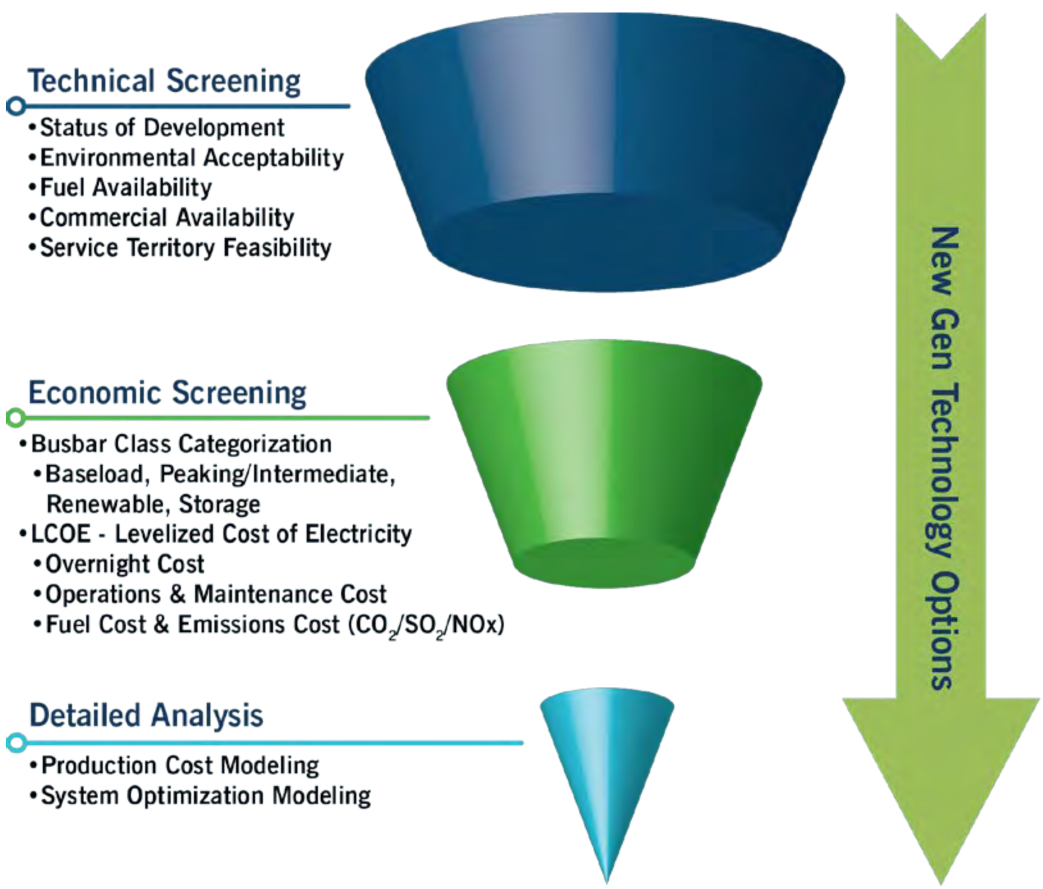
Corrected 11.06.2020

APPENDIX G: SCREENING OF GENERATION ALTERNATIVES

The Company screens generation technologies prior to performing detailed analysis in order to develop a manageable set of possible generation alternatives. Generating technologies are screened from both a technical perspective as well as an economic perspective. In the technical screening, technology options are reviewed to determine technical limitations, commercial availability issues, and feasibility in the Duke Energy service territory.

Economic screening is performed using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves. The technologies must be technically and economically viable in order to be passed on to the detailed analysis phase of the IRP process.

FIGURE G-1
NEW GENERATION TECHNOLOGIES SCREENING PROCESS



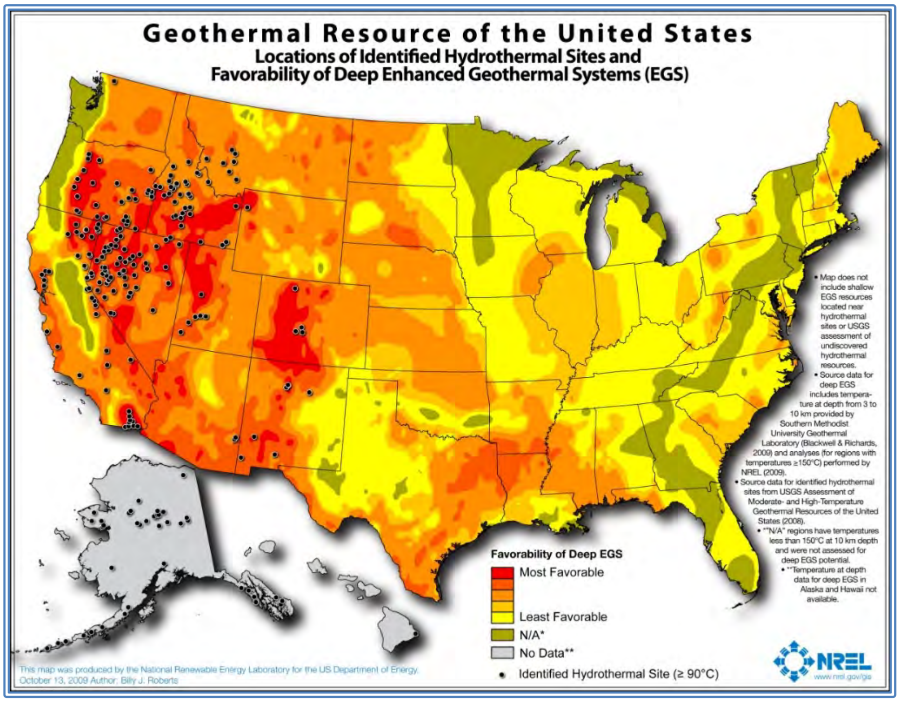
TECHNICAL SCREENING

The first step in the Company's supply-side screening process for the IRP is a technical screening of the technologies to eliminate those that have technical limitations, commercial availability issues, or are not feasible in the Duke Energy service territory. A brief explanation of the technologies excluded at this point and the basis for their exclusion follows:

Fuel Cells, although originally envisioned as being a competitor for combustion turbines and central power plants, are now targeted to mostly distributed power generation systems. The size of the distributed generation applications ranges from a few kW to tens of MW in the long-term. Cost and performance issues have generally limited their application to niche markets and/or subsidized installations. While a medium level of research and development continues, this technology is not commercially viable/available for utility-scale application. However, fuel cells have the potential to provide carbon-free energy if they utilize hydrogen as a fuel source and therefore continue to be reviewed to determine their applicability for future carbon reductions.

Geothermal was eliminated because there are no suitable geothermal resources in the region to develop into a power generation project – see Figure G-2, below. However, advanced geothermal is under development and is performing demonstration projects. Recent developments in deep direct-use geothermal may expand geothermal's applicability into some of the least favorable geological formations as seen in Figure G-2. Although these technologies have not yet reached commercial status, Duke Energy will continue to follow the technology as it may present geothermal energy capability within its service territory in the future.

FIGURE G-2
NREL GEOTHERMAL RESOURCE MAP OF THE U.S.



Small Modular Nuclear Reactors (SMR) are generally defined as having a power output of less than 300 MW per reactor and utilizing water as the coolant. They typically have the capability of grouping a number of reactors in the same location to achieve the desired power generating capacity for a plant. In 2012, the U.S. Department of Energy (DOE) solicited bids for companies to participate in a small modular reactor grant program with the intent to "promote the accelerated commercialization of SMR technologies to help meet the nation's economic energy security and climate change objectives." SMRs continue to gain interest as they contribute no emissions to the atmosphere and, unlike their predecessors, provide flexible operating capabilities alongside inherently safer designs.

NuScale Power is the leader in SMR design and licensing in the US. A NuScale power module is expected to output 60 MW each, and a standard plant offering is expected to contain 12 modules. The NuScale design is expected to receive a certification from the Nuclear Regulatory Committee (NRC) in 2021, which would allow utilities to pursue the design as a new commercial asset. The first NuScale module is expected to reach commercial status in the late 2020s timeframe.

Two additional SMR designs are under development domestically including the GE Hitachi BWRX-300 and the Holtec SMR-160. The BWRX-300 design utilizes design features from the NRC-certified ESBWR, so although GE began their licensing process with the NRC after NuScale, they are expected to reach commercial availability in a similar timeframe. Holtec has not yet submitted a formal design certification request to the NRC and therefore there is no estimated commercialization timeframe in the US.

Similar to 2018, while SMRs were "screened out" in the Technical Screening phase of the technology evaluations due to commercial availability, they were allowed to be selected as a resource in the System Optimizer (SO) model in order to allow the model to meet the high CO_2 emission constraints in the sensitivity analysis. As a result, SMRs have been depicted on the busbar screening curves as an informative item. Duke Energy will be monitoring the progress of the SMR projects for potential consideration and evaluation for future resource plans as they provide an emission-free, diverse, flexible source of generation.

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

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

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

Poultry waste and swine waste digesters remain relatively expensive and are often faced with operational and/or permitting challenges. Research, development, and demonstration continue, but these technologies remain generally too expensive or face obstacles that make them impractical energy choices outside of specific mandates calling for use of these technologies. See Appendix E for more information regarding current and planned Duke Energy poultry and swine waste projects.

Solar Steam Augmentation systems utilize solar thermal energy to supplement a Rankine steam cycle such as that in a fossil generating plant. The supplemental steam could be integrated into the steam cycle and support additional MW generation similar in concept to the purpose of duct firing a heat recovery steam generator. As the price of solar panels continues to drop, solar steam augmentation's economics compared to photovoltaic solar likely prevent this technology from moving forward. However, Duke Energy will continue to monitor developments in the area of steam augmentation.

Supercritical CO_2 Brayton Cycle is of increasing interest; however, the technology is still in the demonstration process. NET Power is the leading developer of the technology and is working on a pilot project. The early issues with the pilot show that the technology has not yet reached commercial status. Duke Energy will continue to monitor pilot and early commercial Supercritical CO_2 Brayton Cycle projects to determine if the technology passes the technical screening in future years.

Hydrogen as a fuel offers an advantage over traditional fossil fuels in not emitting carbon dioxide when burned. There has been substantial renewed interest by the industry in pursuing hydrogen as a replacement fuel for natural gas. Although promising, hydrogen as a utility fuel is still in the early stages from both a production and generation standpoint. Turbine manufacturers have proven successful with hydrogen/natural gas cofiring of up to 30% hydrogen by volume without significant gas turbine alterations in many of the combined cycle and combustion turbine plants currently in operation, dependent on gas turbine type. However, to move to 100% hydrogen-fueled turbines substantial improvements in turbine technology are required. Additionally, hydrogen production would have to increase by many orders of magnitude to have ample supply to match the current production output of natural gas-fueled turbines. Duke Energy will continue to monitor hydrogen technology, both production and generation, to prepare for its potential future use as a natural gas fuel substitute.

Additional Storage technologies continue to be developed and pursued by a variety of companies. The range of technologies is vast and include non-lithium-ion batteries, mechanical storage, thermal storage, and variants of pumped hydro storage. Although some storage technologies passed the technology screening, the majority are still in a pre-commercial status. These technologies continued to be studied as future options for generation and include lead acid batteries, sodium-sulfur batteries, metal-air batteries, subterranean pumped storage, gravitational energy, hydrogen, flywheel energy, liquid air energy, chilled water, molten salt, silicon, concrete, sand, and phase change storage. Duke Energy will continue to monitor the developments and pilots of the various storage options to determine which designs have reached commercial status.

A brief explanation of the technology additions for 2020 compared to the 2018 Integrated Resource Plan submittal and the basis for their inclusion follows:

Compressed Air Energy Storage (CAES) offers an additional method of storage over longer durations than typically found in batteries. CAES is a proven, utility-scale energy storage technology that has been in operation globally for over 30-years. CAES has two primary application methods: diabatic and adiabatic. To utilize CAES, the project needs a suitable storage site, which is typically either a salt cavern or mined hard-rock cavern. Salt caverns have been preferred due to the low cavern construction costs. However, mined hard-rock caverns are now a viable option in areas that do not have salt formations with the use of hydrostatic compensation to increase energy storage density and reduce the cavern volume required. This change to allow mined hard-rock caverns created the potential for CAES in the Carolinas. CAES facilities use off-peak electricity to power a compressor train that compresses air into an underground reservoir. Energy is then recaptured by releasing the compressed air, heating it, and generating power as the heated air travels through an expander.

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

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

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

Although flow batteries' capital costs project to be higher than Li-Ion batteries, flow batteries project to become most effective as the duration of the battery is increased due to energy capacity being dictated primarily by the size of the tanks. Therefore, flow batteries have been included in the technology options as a longer duration storage option.

Offshore Wind is a developing technology in the United States but internationally has become a mature technology. Offshore wind farms have been installed in the oceans off European shores since the 1990s and continue to be an important source of energy in that market. There are several projects in various phases of development in U.S. coastal waters, and more are anticipated as technology and construction advancements allow for installation in deeper waters farther offshore. The Block Island project developed by Deepwater Wind is the first to reach commercial operation, and Duke Energy Renewables is performing remote monitoring and control services for the project. This 30 MW project is located about 3 miles off the coast of Rhode Island.

Duke Energy and NREL studied the potential for offshore integration off the coast of the Carolinas in March 2013. In 2015, the U.S. Bureau of Ocean Energy Management (BOEM) completed environmental assessments at three potential Outer Continental Shelf (OCS) sites off the coast of North Carolina. In March 2017, BOEM administered a competitive lease auction for wind energy in federal waters and awarded Avangrid Renewables the rights to develop an area off the shores of Kitty Hawk. Avangrid has plans for a project that may be as large as 2,400 MW.

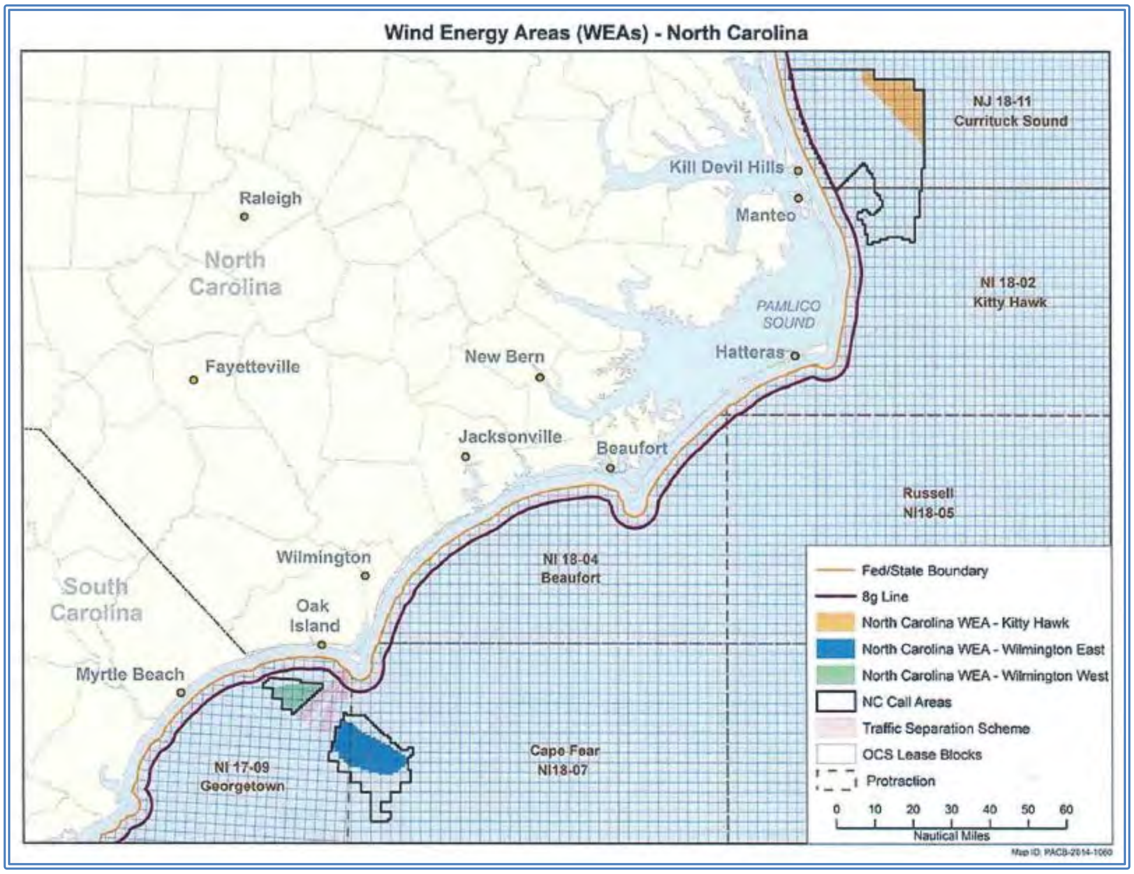
Several coastal states including New York, New Jersey, Maryland, Massachusetts, Connecticut, California, Rhode Island, Delaware, and Virginia have been forecasted to have projects developed. New York has an Offshore Wind Master Plan aimed at 2,400 MW of offshore projects by 2030, and Statoil is developing the 1,500 MW Empire Wind project near New York City, aiming for completion in 2025.

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

Although technology costs still remain high for offshore wind, the technology is being evaluated as an additional renewable option. The profile of offshore wind allows for a higher capacity factor in the Carolinas than onshore wind, and the profile also compliments solar energy.

FIGURE G-3

NC WIND ENERGY AREAS (WEAS) (DEVELOPED IN JOINT VENTURE BY DUKE ENERGY AND NREL)



GENERATION FLEXIBILITY AND DUKE ENERGY CLIMATE PLAN

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

Additionally, in 2020 Duke Energy released a revision to its previous Climate Report with aggressive goals to reduce output from its generating facilities by 2030 and even deeper reductions by 2050. Duke Energy concluded that it would need new technologies that have not yet reached commercialization status that performed as Zero-Emitting Load-Following Resources (ZELFR). The load-following requirement comes from the flexibility need described above, and the zero-emission portion is to help Duke Energy meet its future climate goals.

Duke Energy is evaluating several generation technologies that are considered pre-commercial to meet the ZELFR need. Technologies considered typically fall under the broad categories of advanced nuclear, advanced renewables, advanced transmission and distribution, biofuels, carbon capture utilization and sequestration, fuel cells, hydrogen, long duration energy storage, and supercritical CO_2 Brayton Cycle. All of these technologies are expected to help Duke Energy meet future carbon reduction goals if they reach commercial status and are economically competitive.

Duke Energy expects multiple technologies to be required to meet its carbon reduction goals, and therefore Duke Energy is considering potential paths to help move these technologies towards commercialization. One such effort Duke Energy is pursing is the recently announced partnership with two advanced reactor developers on DOE's Advanced Reactor Deployment Program to deploy one of the first two advanced nuclear reactors. Another effort underway is the collaborative work with Siemens as part of DOE's Energy Storage for Fossil Generation Program to evaluate the possibility of hydrogen co-firing at the Combined Heat and Power Plant on Clemson's campus. Duke Energy recognizes the potentially long commercialization timeframe for some of these technologies and will continue to pursue efforts to move these important technologies forward.

Although these technologies all screen out in the process due to their commercial status, Duke Energy will continue to follow a wider range of technologies to meet these future generation needs.

ECONOMIC SCREENING

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

The screening within each general class of busbar (Baseload, Peaking/Intermediate, Renewables and Storage), as well as the final screening across the general classes, uses a spreadsheet-based screening curve model developed by Duke Energy. This model is considered proprietary, confidential and competitive information by Duke Energy. Again, for the 2020 IRP year, Duke Energy has provided an additional set of busbar curves to represent Storage technology comparisons. As Storage technologies are not traditional generating resource options, they should be compared independently from generating resources. In addition, there has been no *charging* cost associated with the storage busbar buildup. This charging cost is excluded as it is dependent upon what the next marginal unit is in the dispatch stack as to what would be utilized to "charge" the storage resource. For resource options inclusive of or coupled with storage, it is assumed that the storage resource is being directly charged by the generating resource (i.e. Solar PV plus Battery Storage option).

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

The Company selected the technologies listed below for the screening curve analysis. While future carbon emission constraints may effectively preclude new coal-fired generation, Duke Energy has included ultra-supercritical pulverized coal (USCPC) with carbon capture sequestration (CCS) and integrated gasification combined cycle (IGCC) technologies with CCS of 1400 pounds/net MWh capture rate as options for baseload analysis. 2020 additions include Offshore wind, additional Lithium Ion Battery Storage options, Flow Battery Storage, and Advanced Compressed Air Energy Storage.

DUKE ENERGY CAROLINAS

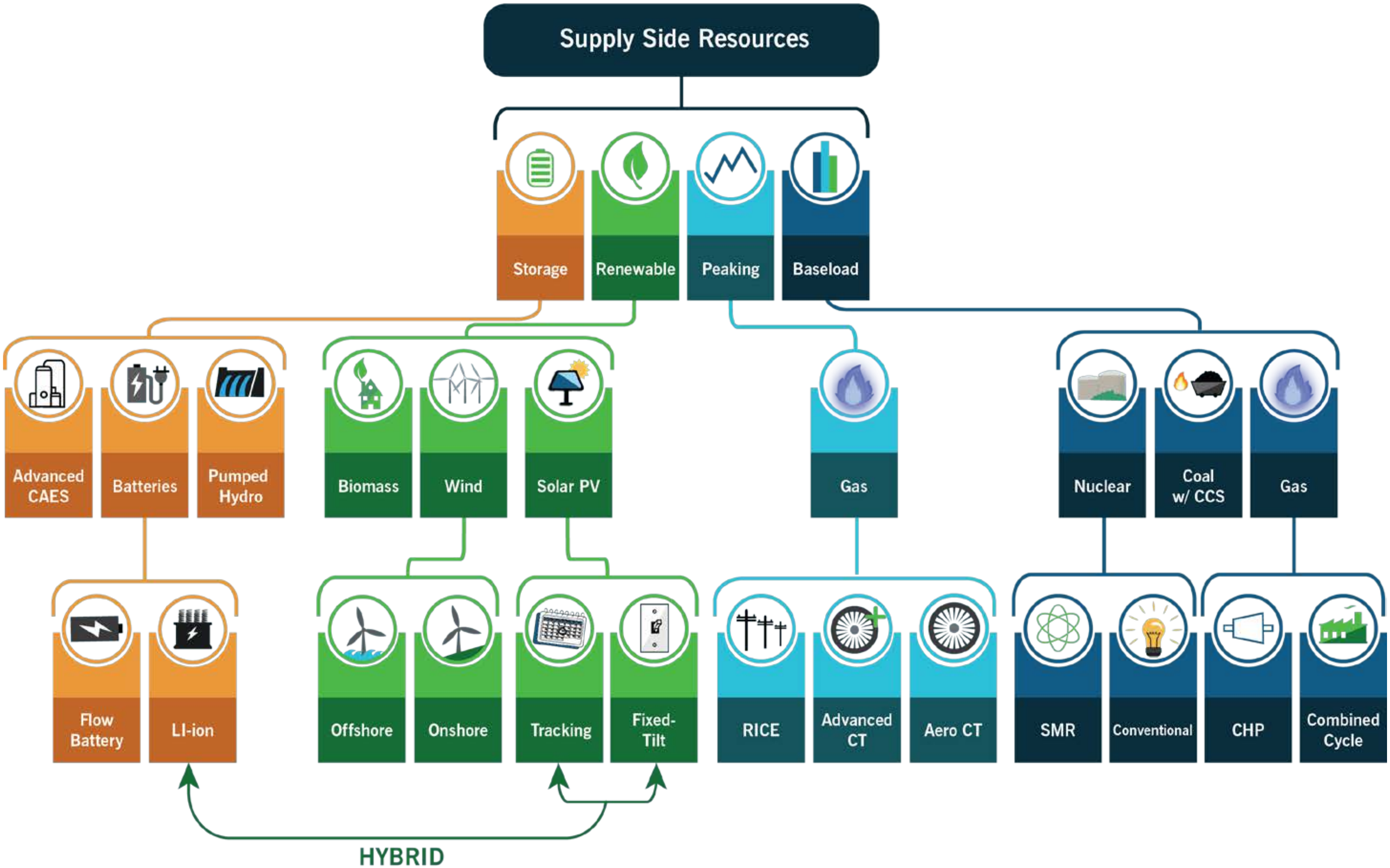
DISPATCHABLE (WINTER RATINGS)

BASELOAD	PEAKING / INTERMEDIATE	STORAGE	RENEWABLE
601 MW, 1x1x1 Advanced Combined Cycle (No Inlet Chiller and Fired)	18 MW, 2 x Reciprocating Engine Plant	10 MW / 10 MWh Lithium-ion Battery	75 MW Wood Bubbling Fluidized Bed (BFB, biomass)
1,224 MW, 2x2x1 Advanced Combined Cycle (No Inlet Chiller and Fired)	15 MW Industrial Frame Combustion Turbine (CT)	10 MW / 20 MWh Lithium-ion Battery	5 MW Landfill Gas
782 MW Ultra-Supercritical Pulverized Coal with CCS	192 MW, 4 x LM6000 Combustion Turbines (CTs)	10 MW / 40 MWh Lithium-ion Battery	**NON- DISPATCHABLE (WINTER RATINGS)**
557 MW, 2x1 IGCC with CCS	201 MW, 12 x Reciprocating Engine Plant	50 MW / 200 MWh Lithium-ion Battery	150 MW Onshore Wind
720 MW, 12 Small Modular Reactor Nuclear Units (NuScale)	752 MW, 2 x J-Class Combustion Turbines (CTs)	50 MW / 300 MWh Lithium-ion Battery	600 MW Offshore Wind
2,234 MW, 2 Nuclear Units (AP1000)	913 MW, 4 x 7FA.05 Combustion Turbines (CTs)	20 MW / 160 MWh Redox Flow Battery	75 MW Fixed-Tilt (FT) Solar PV
9 MW Combined Heat & Power (Reciprocating Engine)		250 MW / 4,000 MWh Advanced Compressed Air Energy Storage	75 MW Single Axis Tracking (SAT) Solar PV
21 MW – Combined Heat & Power (Combustion Turbine)		1,400 MW Pumped Storage Hydro (PSH)	75 MW SAT Solar PV plus 20 MW / 80 MWh Lithium-ion Battery

Corrected 11.06.2020

FIGURE G-4

DUKE ENERGY, SCREENED-IN SUPPLY SIDE RESOURCE ALTERNATIVES



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INFORMATION SOURCES

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

CAPITAL COST FORECAST

A capital cost forecast was developed with support from a third party to project not only Renewables and Battery Storage capital costs but the costs of all resource technologies technically screened in. The Technology Forecast Factors were sourced from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2020 which provides cost projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS) utilized by the EIA for the AEO.

Using 2020 as a base year, an " annual cost factor is calculated based on the change from a base year for the macroeconomic variable tracking the metals and metal products producer price index, thereby creating a link between construction costs and commodity prices." (NEMS Model Documentation 2018, April 2019)

From *NEMS Model Documentation 2018, April 2019*:

> *"Uncertainty about investment costs for new technologies is captured in the ECP [Electricity Planning Submodule] using technological optimism and learning factors. The technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development. As development proceeds and more data become available, cost estimates become more accurate and the technological optimism factor declines.*
>
> *Learning factors represent reductions in capital costs as a result of learning-by-doing. Learning factors are calculated separately for each of the major design components of the technology. Generally, overnight costs for new, untested components are assumed to decrease by a technology specific percentage for each doubling of capacity for the first three doublings, by 10% for each of the next five doublings of capacity, and by 1% for each further doubling of capacity. For mature components or conventional designs, costs decrease by 1% for each doubling of capacity."*

The resulting Forecast Factor Table developed from the EIA technology maturity curves for each corresponding technology screened is depicted in Table G-1.

TABLE G-1

SNAPSHOT FROM FORECAST FACTOR TABLE BY TECHNOLOGY (EIA - AEO 2020)

YEAR	FRAME CT	AERO CT	NUCLEAR	BATTERY STORAGE	1X1 COMBINED CYCLE	ONSHORE WIND
2020	1.000	1.000	1.000	1.000	1.000	1.000
2021	0.985	0.987	0.984	0.812	0.987	0.987
2022	0.970	0.973	0.967	0.718	0.973	0.973
2023	0.950	0.961	0.950	0.640	0.961	0.961
2024	0.901	0.953	0.920	0.625	0.953	0.953
2025	0.873	0.945	0.909	0.609	0.945	0.945
2026	0.852	0.937	0.898	0.594	0.937	0.937
2027	0.831	0.928	0.886	0.579	0.927	0.928
2028	0.815	0.918	0.874	0.563	0.918	0.918
2029	0.803	0.907	0.861	0.546	0.907	0.907
2030	0.789	0.896	0.847	0.530	0.896	0.896

SCREENING RESULTS

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

The peaking technology screening included F-frame and J-Frame combustion turbines, fast start aero-derivative combustion turbines, and fast start reciprocating engines. The screening curves show the F-frame CTs to be the most economic peaking resource unless there is a special application that requires the fast start capability of the aero-derivative CTs or reciprocating engines. Reciprocating engine plants offer the lowest heat rates and fastest start times among simple cycle options. Simple cycle aeroderivative gas turbines remain in close contention with reciprocating engines. Should a need be identified for one of these two types of resources, a more in-depth analysis would be performed.

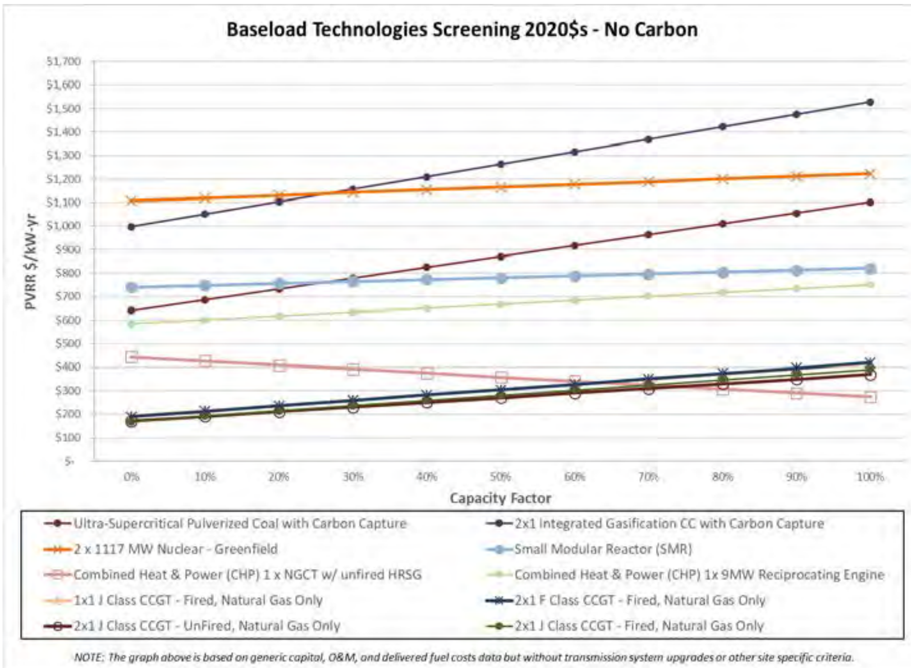
The renewable screening curves show solar continues to be a more economical alternative than other renewable resource options. Solar and wind projects are technically constrained from achieving high capacity factors making them unsuitable for intermediate or baseload duty cycles. Landfill gas and biomass projects are limited based on site availability but are dispatchable. Landfill gas is not shown in the busbar curve for renewables as the options are limited since most sites have already been transacted with. Although solar PV prices have become competitive with conventional generators, the lack of dispatchability and low capacity factor does not allow it to be a baseload resource.

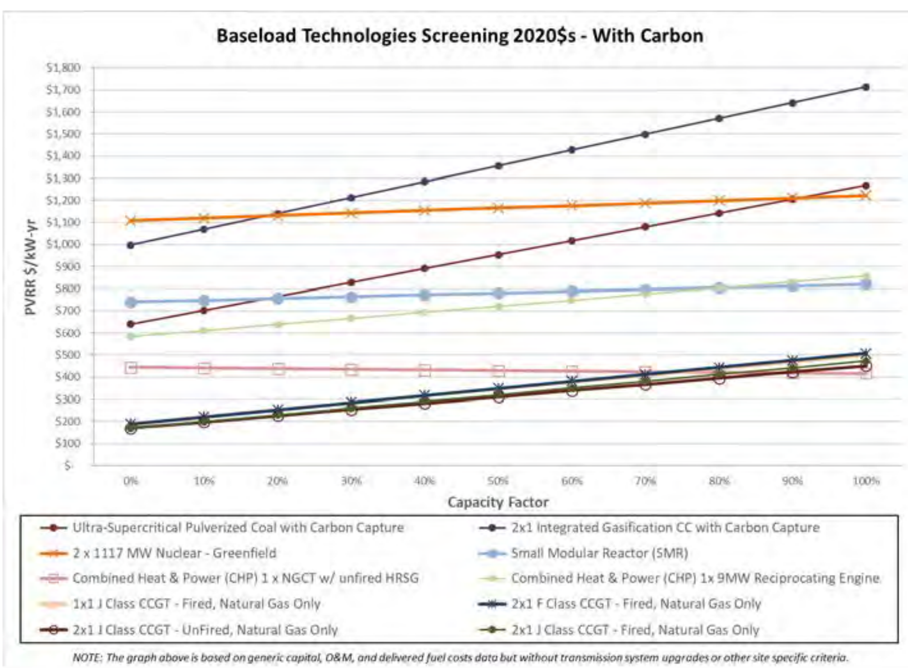
Energy storage has become an increasingly important asset as companies add more variable resources to their portfolio. Energy storage can provide a variety of benefits to the grid and overall resource portfolio. Additional information on energy storage can be found in Appendix H. For the screening results, the lowest $/kW option for energy storage was 1-hour duration Li-Ion storage as expected. However, batteries have a variety of use cases and longer duration storage can be more useful than shorter duration storage in certain cases. Additionally, the $/kWh decreases as the duration of the storage increases. So, although the 1-hour duration Li-Ion battery storage asset had the lowest screening cost, the specific application of the storage option will determine which storage option is the best fit for its use case.

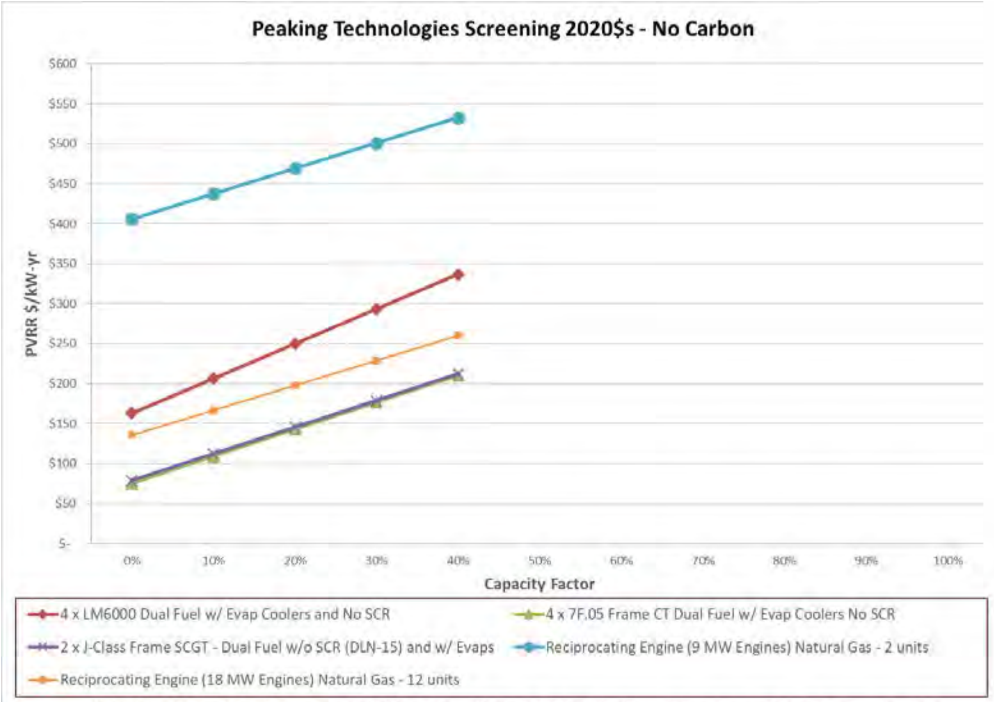
The screening curves are useful for comparing costs of resource types at various capacity factors but cannot be solely utilized for determining a long-term resource plan because future units must be optimized with an existing system containing various resource types. Results from the screening curve analysis provide guidance for the technologies to be further considered in the more detailed quantitative analysis phase of the planning process.

SCREENING CURVES

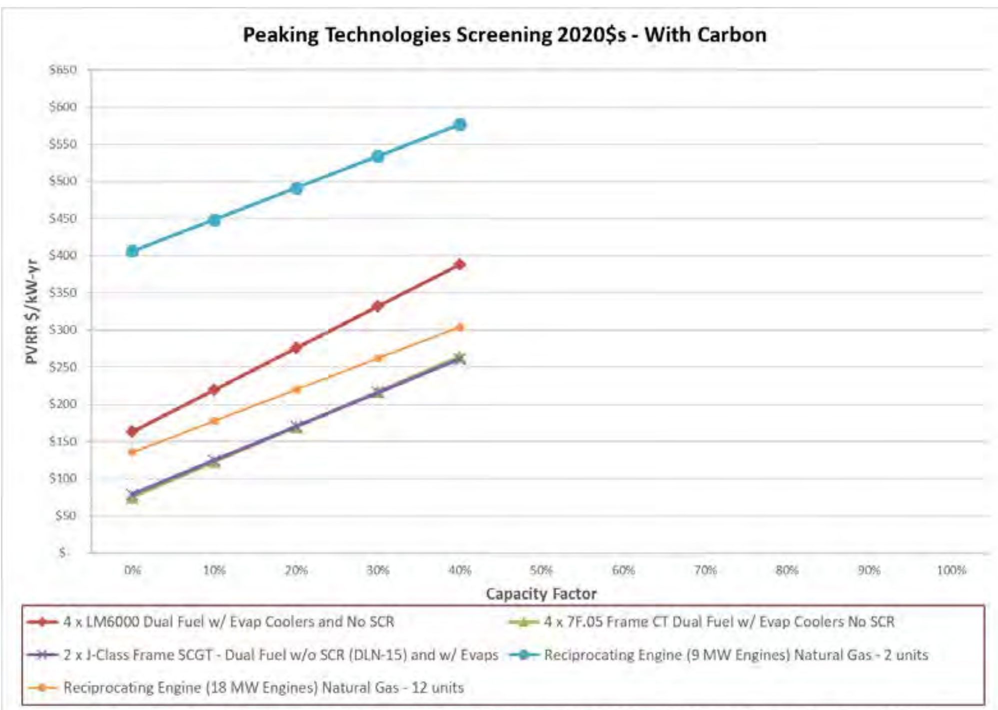
The following pages contains the technology screening curves for baseload, peaking/intermediate, renewable and storage technologies.



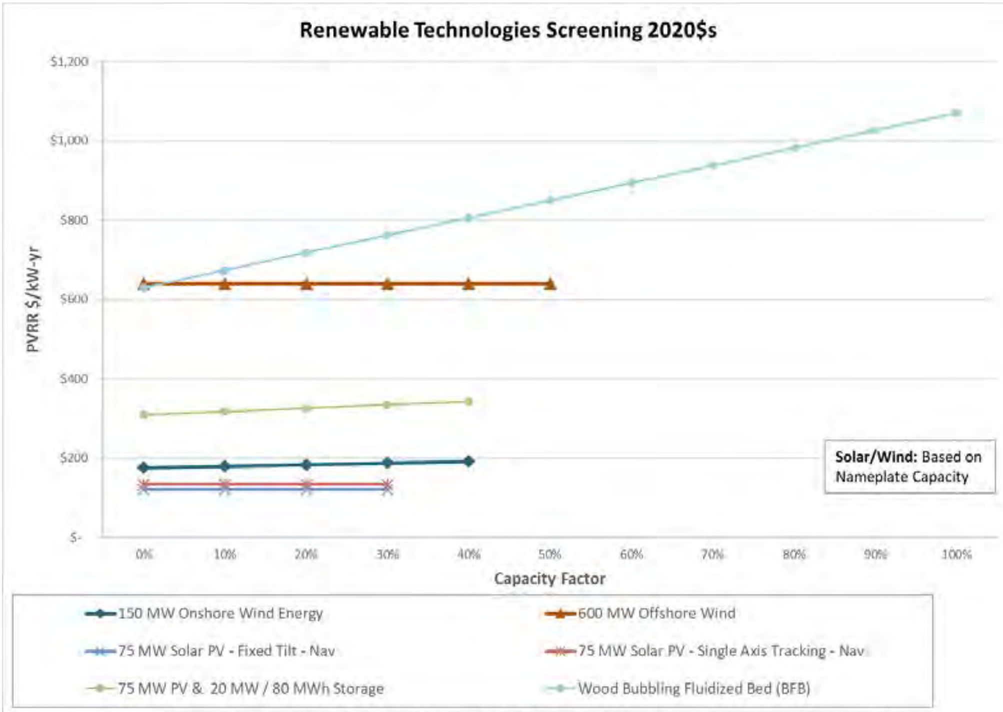




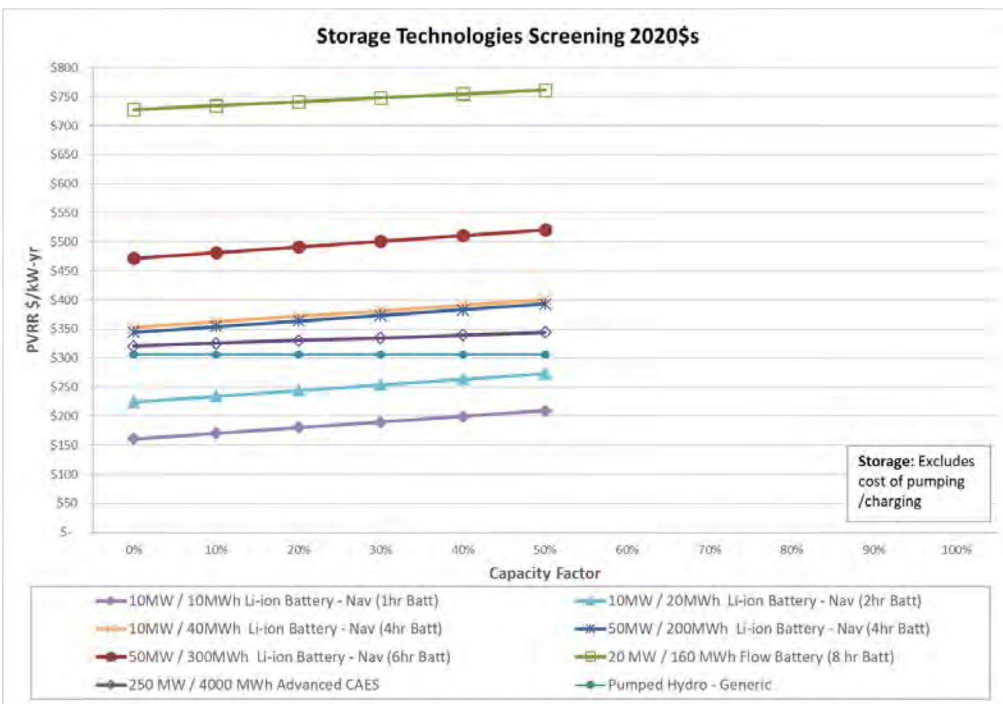
NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission system upgrades or other site specific criteria.



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



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



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

ENERGY STORAGE

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APPENDIX H: ENERGY STORAGE

Battery storage is expected to play an important role in meeting future needs on the DEC system. As discussed in Chapter 6, battery storage can provide multiple services. For purposes of the 2020 IRP, the Company considered capacity, energy arbitrage, and ancillary service benefits when valuing battery storage. Additionally, the Company conducted a thorough review of battery cost and operating assumptions modeled in the 2020 IRP. Benchmarking battery storage costs across publications is difficult, and oftentimes not possible, due to disparate definitions and incomplete documentation. Some publications do not include the full cost that would be needed to construct a battery storage system that would meet the requirements of a manufacturer's warranty and the needs of the Utility over the life of the asset. For this reason and to provide transparency of the cost estimating process, the Company is detailing the battery storage assumptions used in the 2020 IRP below.

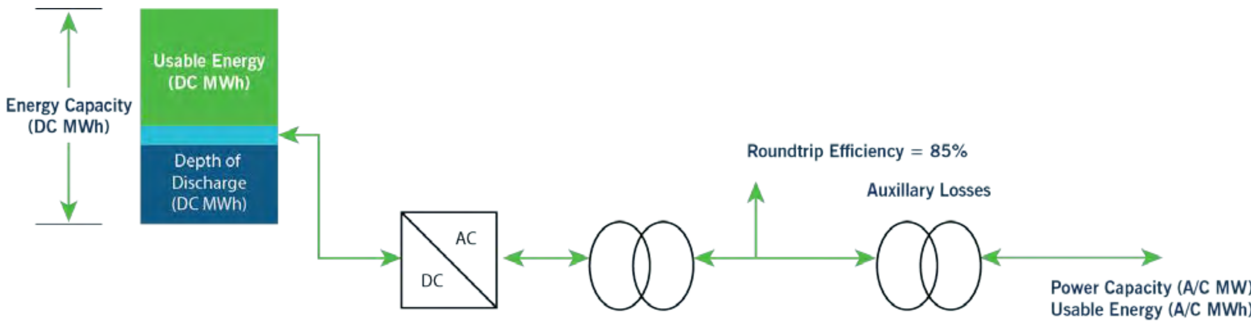
Finally, in order to appropriately estimate the capacity value battery storage can provide, the Company hired a third-party consultant to conduct an Effective Load Carrying Capability ("ELCC") study to quantify the contribution to winter peak demand that battery storage could provide in DEC. The results of the ELCC study are described in the following sections and the Battery Storage ELCC study has been filed along with the IRP filing.

BATTERY STORAGE TERMINOLOGY AND OPERATING ASSUMPTIONS

Some of the terminology that the Company uses to describe batteries in the IRP is detailed below. Importantly, while many of the terms and definitions below are standard across the industry, some of the terms are specific to how battery storage is described in this IRP and may not match what is described in other publications. Where appropriate, definitions that are taken directly from outside publications are cited. The following is a diagram of a standalone battery storage system that is modeled in the 2020 IRP.

FIGURE H-1

SIMPLIFIED BATTERY STORAGE SYSTEM MODELED IN 2020 DEC IRP



- **Battery size –** Battery sizing is generally provided in capacity and energy values or capacity value and duration. The terms “capacity”, “energy”, and “duration” are discussed below. An example of battery size nomenclature is “50 MW / 200 MWh” which represents a 50 MW battery with a 4-hour duration.

- **Capacity –** Generally referred to as “power capacity” in the industry and represents the total possible instantaneous discharge capability of the battery storage system, or the maximum rate of discharge the battery can achieve starting from a fully charged state.[1] The Company measures power capacity at the point of interconnect to the transmission system and the units are “MW AC.” The IRP represents the cost of a battery in $/MW where the numerator, or dollars, is the total cost of the battery system and the denominator is the power capacity in MW AC of the system. The components of the total cost of the battery system are described in further detail below.

- **Energy –** The energy that a battery can hold can be represented differently between publications which can make comparing costs between sources of data difficult. For the purposes of this IRP, the Company considers energy in the following manners:

    - **Usable Energy –** Refers to the amount of energy that can be discharged at the point of interconnection over the duration of the battery. Usable energy can be described in units of “MWh AC” or “MWh DC.” When the Company discusses the cost of a battery on a $/MWh basis, the numerator is the total cost of the battery system and the denominator is the usable energy in units of MWh AC.

[1] https://www.nrel.gov/docs/fy19osti/74426.pdf,

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- **Depth of Discharge (DoD) –** "Indicates the percentage of the battery that has been discharged relative to the overall [energy] capacity of the battery."[2] In the 2020 IRP, this number represents the amount of energy that must remain, unused, in the battery to satisfy the warranty of the battery and/or allow the battery to complete the expected number of cycles over the life of the asset. For instance, the Company uses a 20% depth of discharge limit which simply means the battery cannot discharge more than 80% of its energy capacity. Some publications only provide battery costs based on the usable energy of the battery thereby ignoring the DoD; however, the Company calculates the cost of a battery based on the energy capacity, which includes the DoD limitation.

- **Energy Capacity –** The total amount of energy that can be stored or discharged by the battery storage system.[3] In the diagram above, energy capacity is the sum of the usable energy and the depth of discharge limit. Energy capacity is defined in units of "MWh DC." The Company did not include additional costs for other "unused" energy required to maintain the contracted usable energy of the battery, such as additional energy capacity to account for DC or AC losses that occur during charge and discharge of the battery. However, within the production cost model, the Company does account for the production cost impacts of losses on roundtrip efficiency of the battery as discussed below.

- **Duration –** "Amount of time storage can discharge at its power capacity. "[4] For example, a battery with 50 MW of power capacity and 200 MWh of usable energy capacity will have a storage duration of 4 hours.

- **Roundtrip Efficiency –** "Measured as a percentage, is a ratio of the energy charged to the battery to the energy discharged from the battery. It can represent the total DC-DC or AC-AC efficiency of the battery system, including losses from self-discharge and other electrical losses."[5] The Company uses A/C - A/C efficiency as the production cost models only consider the charging/discharging at the point of interconnect to the power system. The Company

[2] https://news.energysage.com/depth-discharge-dod-mean-battery-important/#:~:text=A%20battery's%20depth%20of%20discharge,DoD%20is%20approximately%2096%20percent.
[3] U.S. Battery Storage Trends, U.S. Energy Information Administration, May 2018.
[4] https://www.nrel.gov/docs/fy19osti/74426.pdf.
[5] https://www.nrel.gov/docs/fy19osti/74426.pdf.

assumed a roundtrip efficiency of 85% for all lithium-ion (Li-ion) batteries modeled in the 2020 IRP.

- **Auxiliary Losses -** Included as part of other electrical losses in the calculation of round-trip efficiency and can include power required for HVAC systems associated with the battery storage system.

- **Degradation –** The loss of energy capacity of a battery storage system overtime. "Degradation of lithium-ion batteries is impacted by several variables. Known drivers of degradation include: temperature of operation, average state of charge over its lifetime, and depth of charge-discharge cycles."[6] Figure 2, sourced from NREL's "Life Prediction Model for Grid Connected Li-ion Battery Energy Storage System" demonstrates the effects that DoD and temperature management of the battery storage system can have on degradation.

[6] https://www.energy-storage.news/blogs/is-that-battery-cycle-worth-it-maximising-energy-storage-lifecycle-value-wi#:~:text=Battery%20storage%20degradation%20typically%20manifests,need%20for%20replacement%20of%20batteries.

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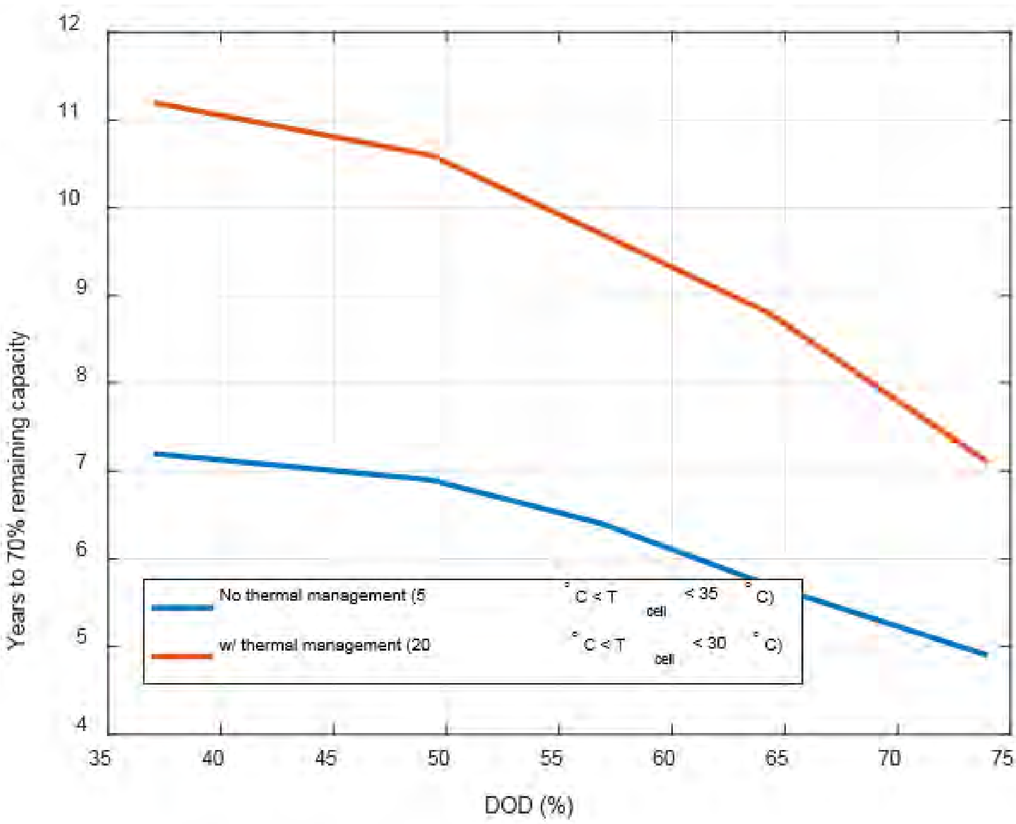
FIGURE H-2
IMPACT OF BATTERY OVERSIZING AND THERMAL MANAGEMENT ON LIFETIME FROM NREL[7]



- **Battery Augmentation –** As a battery storage system experiences degradation, battery cells can be replenished on a regular, or semi-regular, basis to maintain the usable energy of the battery storage system. This strategy to counteract degradation leads to lower initial capital costs but incurs higher on-going costs throughout the life of the asset. For IRP purposes, the Company assumes a Battery Augmentation strategy to minimize total costs over the 15-year assumed life of the battery asset, while recognizing that this approach does present some challenges with maintaining stable performance of the system.

- **Overbuild –** Refers to an increase in the nameplate energy capacity to account for expected degradation. As an alternative strategy to augmentation, the battery storage system can

[7] https://www.nrel.gov/docs/fy17osti/67102.pdf.

initially be physically oversized beyond depth of discharge limits to account for degradation. This strategy yields higher initial capital costs but lower on-going costs versus an augmentation strategy.

BATTERY STORAGE COST ASSUMPTIONS

Battery storage costs have been declining rapidly over the last several years, and they are expected to continue declining for the foreseeable future. In fact, the Company assumes that battery prices will drop by nearly 50% over the next 9 years.[8]

The Company's capital cost assumptions are developed by a third party and are benchmarked against both internal and external sources. Often, the Company's prices appear higher than published numbers. As discussed above, there are several factors that can drive this difference including:

- The Company calculates the cost of a battery storage device assuming a 20% DoD limit while other publications likely only calculate the cost of the battery based on the rated energy of the battery from their information sources, which often do not specify whether their energy rating factors in DoD. In cases where the energy rating does not account for DoD, the cost of the battery can differ by over 10%.

- The Company assumes interconnection costs based on historical costs on the DEC system. Other publications may include lower interconnection costs or may not account for interconnection costs altogether.

- Because the Company expects to rely on these assets for at least 15-years to provide reliable capacity and energy to its customers on a real-time basis, some of the Company's assumptions of software and controls may lead to higher capital costs than a device that is designed to provide capacity and energy with lower reliability standards or on a more standard schedule.

- Similarly, the Company may be including more expensive HVAC and fire detection and suppression assumptions when calculating the cost of the battery storage system. It is the Company's belief that this cost is warranted for safety and protection of employees as well as the assets.

[8] Real 2020$; prices drop by 34% in nominal terms assuming 2.5% inflation rate.

- Due to low installed capacity and limited operational experience with battery storage on the DEC system, the Company assumes that system integration costs of a battery would be on the level of a custom application rather than a basic, or turnkey, level of cost. It is likely however, that as battery storage becomes more pervasive on the DEC system, system integration costs will decline, and battery storage costs could decline further than the near 50% decline already assumed in the IRP. The Company will monitor developments in this area and adjust as appropriate in future IRPs.

As stated previously, it is very difficult to determine what is included in the cost assumptions for battery storage in publications, particularly with regards to software and controls, HVAC, fire detection and suppression, and system integration costs. The following are the assumptions the Company includes for the percent contribution of costs from various components of a battery storage system along with the projected cost trend through 2029 in nominal terms assuming 2.5% inflation.[9]

TABLE H-1

COST COMPONENTS OF BATTERY STORAGE IN 2020 IRP

COMPONENT	% OF TOTAL COST[10]	PROJECTED COST TREND THROUGH 2029
Battery Pack	53%	-51%
Power Electronics	3%	-40%
Software and Controls	1%	-8%
Balance of Plant	9%	-15%
Systems Integration	15%	-30%
Site Installation	8%	3%
Project Development Fees	6%	-24%
Interconnection Fees	5%	25%

As further context to the above cost allocations and assumptions, EPRI recently conducted a survey of its members regarding cost assumptions of battery storage. Many members use public sources

[9] Initial value based on 2020 cost of a 50 MW / 200 MWh battery storage system in the 2020 IRP.

[10] Values based on total cost without owner's costs. Owner's costs are consistent with the costs incurred during the development of the Company's previous storage projects.

such as NREL, Lazard, and EPRI, in addition to commercial third-party forecasts and in-house SME input, when developing battery storage price forecasts. Importantly, members do not simply rely on published numbers without making some adjustments. Members identified adding costs for items such as interconnection, A/C balance of plant, substation, land, and civic infrastructure. Nearly half of respondents factor in costs associated with a state of charge (SOC) window or depth of discharge limitation when developing cost estimates. Finally, one cost that DEC does not account for are end-of-life costs for disposal and recycling of battery storage components. Just over half of respondents account for these costs and the Company will evaluate adding end-of-life costs in future IRPs.

EFFECTIVE LOAD CARRYING CAPABILITY (ELCC) OF BATTERY STORAGE

The Company commissioned Astrapé Consulting, a nationally recognized expert in the field, to conduct a Storage Effective Load Carrying Capability (ELCC) Study of battery storage to determine the capacity value that short-duration storage can provide towards meeting DEC's winter peak demand. The ELCC study evaluated both standalone storage, as well as, DC coupled solar plus storage over a range of storage penetrations, durations, and solar levels. The results of the study are highlighted below, and the full report is filed with the IRP as Attachment 4. Importantly, the study confirmed that initial additions of storage can provide nearly 100% contribution to winter peak, however the ELCC contribution of energy storage decreases rapidly with increasing penetration of battery storage as is the case with any energy limited resource.

STANDALONE STORAGE ELCC

The following matrix depicts the range of scenarios evaluated in the ELCC study under a base level of solar (2,700 MW) and a high level of solar (4,500 MW).

TABLE H-2

STANDALONE STORAGE RUN MATRIX FOR ELCC STUDY

	STANDALONE BATTERY DURATION (HRS)		
Duration / Cumulative Battery Capacity	2	4	6
400 MW			
800 MW (incr 800)			
1,200 MW (incr 800)			
2,000 MW (incr 800)			

The sensitivities analyzed in the matrix above were conducted separately for each battery duration. For example, 6-hour batteries were studied as if there were no 4-hour or 2-hour batteries on the DEC system. In this manner, the ELCC represents the value of a 6-hour battery without the impacts of other incremental storage on the system. An additional sensitivity was analyzed which studied the impacts of 6-hour storage if up to 800 MW of 6-hour storage were placed on the system *after* 2,000 MW of 4-hour storage were already operating in DEC.

The ELCC of standalone storage was determined separately under the following three conditions:

- Preserve Reliability – Assumes full control of the battery and only dispatches the battery during emergency events to avoid firm load shed, maintains charge at all times possible. Results in highest possible capacity value but low economic value.

- Economic Arbitrage – Assumes DEC maintains full control of the battery and dispatches the battery based on a daily schedule to maximize economics. This mode of operation allows for the schedule to deviate during emergency events as they occur. Uncertainty in the model is driven by generator outages, day ahead load and solar uncertainty.

- Fixed Dispatch – Assumes DEC has no control of the battery, and the battery charges and discharges against a fixed set of prices. To model this condition, hourly avoided cost values from NC Docket E-100 Sub 158 were used to set the dispatch schedule of the battery. This scenario was developed to demonstrate the impact to storage capacity value if DEC did not have dispatch rights to the storage asset.

The following three figures depict the capacity value of 2-hour, 4-hour, and 6-hour storage under the three operating conditions described above.

FIGURE H-3
AVERAGE CONTRIBUTION TO DEC WINTER PEAK IN PRESERVE RELIABILITY MODE

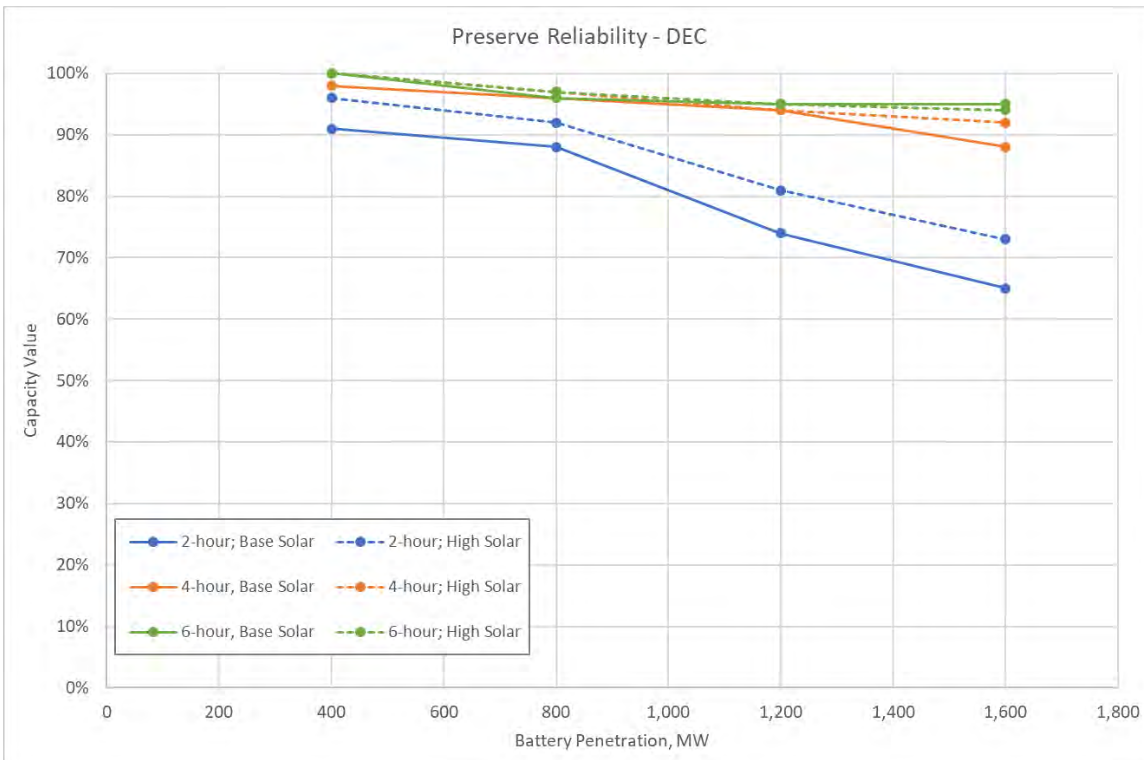


FIGURE H-4

AVERAGE CONTRIBUTION TO DEC WINTER PEAK IN ECONOMIC DISPATCH MODE

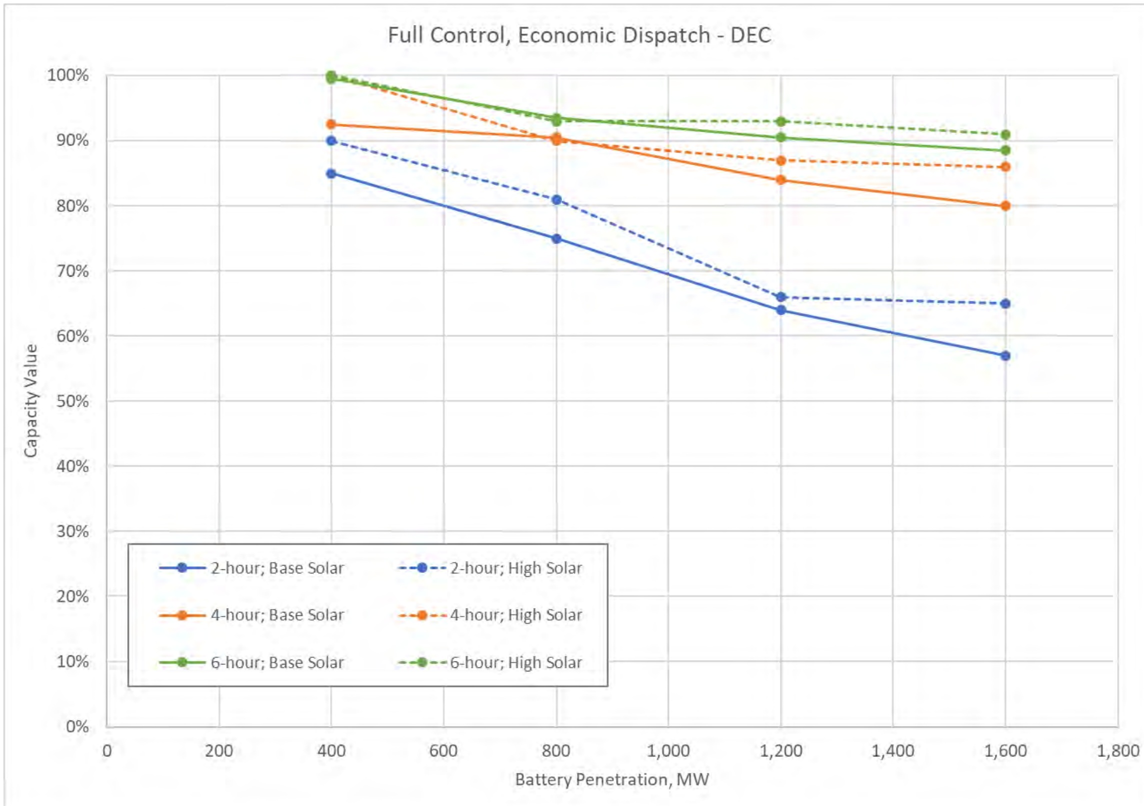
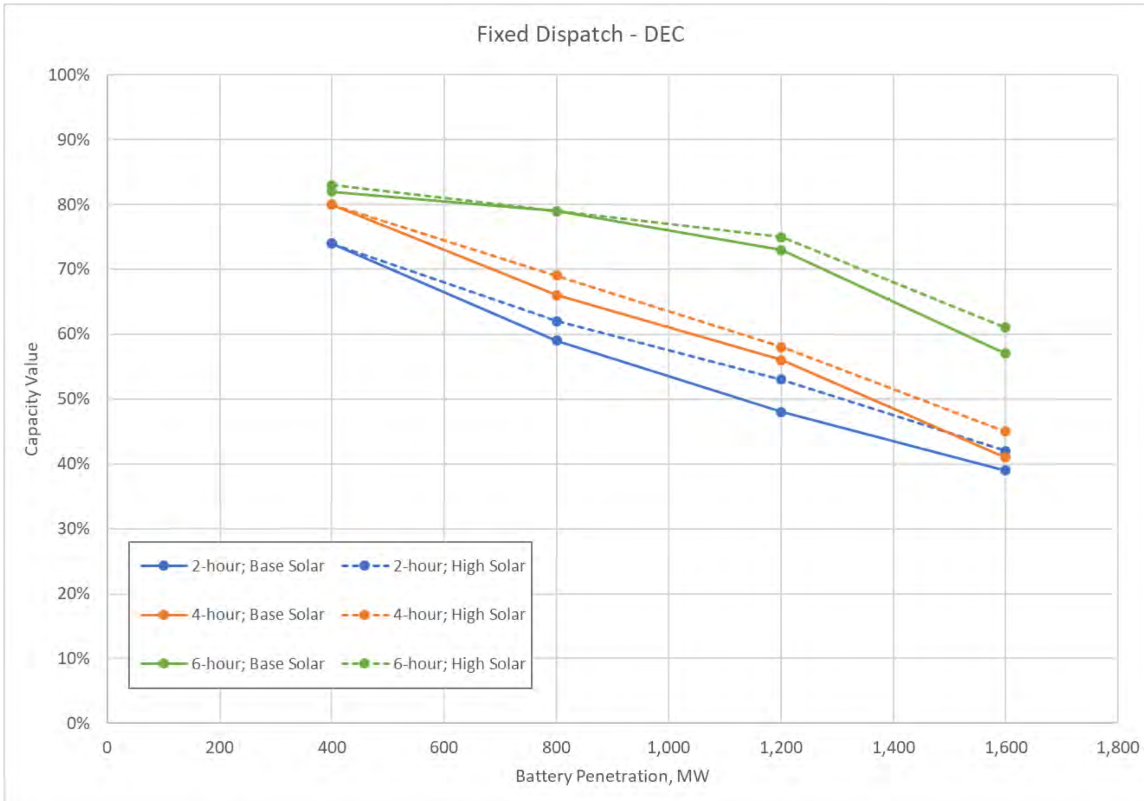


FIGURE H-5

AVERAGE CONTRIBUTION TO DEC WINTER PEAK IN FIXED DISPATCH MODE



The results of the sensitivity of 6-hour storage added after 1,600 MW of 4-hour storage are shown in the following chart.

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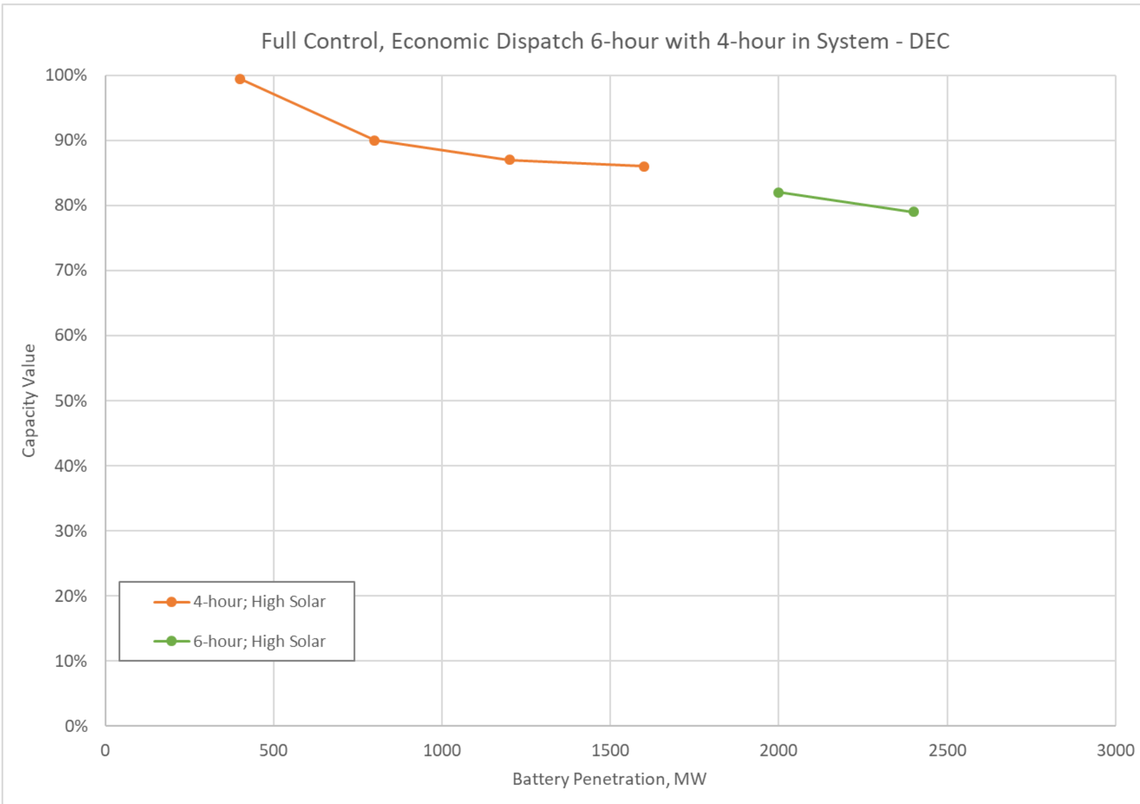
FIGURE H-6

AVERAGE CONTRIBUTION TO DEC WINTER PEAK FOR 6-HOUR STORAGE WITH 4-HOUR ON SYSTEM



Based on the results of the study, DEC made the following assumptions in development of the 2020 IRP:

- **All storage capacity values based on Economic Dispatch** – The IRP model maximizes the value of battery storage by charging the battery with lower cost energy and discharging the stored energy during periods where energy has more value. The model does not maintain full charge in all hours and forego economic benefit to customers to ensure the battery is available to meet demand if a generator on the system experiences an unplanned outage. Similarly, in practice, a board operator does not have perfect foresight of forced outages and would likely use the battery when it is economically prudent based on what they see at the time. Alternatively, as demonstrated in the results above, the value of battery storage for DEC's customers is maximized when the utility maintains dispatch rights for the battery asset. For these reasons, the Company relied on the ELCC results modeled under Economic Arbitrage conditions.

- **Only 4-hour and 6-hour storage considered for standalone storage** – Under all dispatch options, the value of 2-hour storage quickly diminishes as their penetration increases on the system. As shown in Appendix B of the Resource Adequacy report (Attachment III of the IRP), even though most of the LOLH occurs in the hour beginning 7AM, DEC has LOLH over a range of hours in the morning and evening which limits the value that 2-hour storage can provide to the system. Additionally, two-hour storage generally performs the same function as DSM programs that, not only reduce winter peak demand, but also tend to flatten demand by shifting energy from the peak hour to hours just beyond the peak. This flattening of peak demand is one of the main drivers for rapid degradation in capacity value of 2-hours storage. As the Company seeks to expand winter DSM programs, the value of two-hour storage will likely diminish.

While the above results show the average capacity value attributed to varying levels of storage on the DEC system, the incremental value of adding 400 MW blocks of storage can be calculated from the results. The incremental values are useful when determining the capacity value of the next block of energy storage, particularly when evaluating replacing a CT with a 4-hour battery as discussed in Appendix A and the economic coal retirement discussion Chapter 11. The incremental capacity value of storage assumed in the IRP is shown in the following table.

TABLE H-3

INCREMENTAL CONTRIBUTION TO PEAK FOR 4- AND 6-HOUR STORAGE IN DEC

SOLAR PENETRATION	DURATION	STORAGE CAPACITY	INCREMENTAL CONTRIBUTION TO WINTER PEAK
Base Renew	4-hour	0 - 800	90%
		800 - 1,600	70%
	6-hour	0 - 400	100%
		400 - 1,600	85%
High Renew	4-hour	0 - 400	100%
		400 - 1,600	80%
		1,600 - 2,200	70%
	6-hour	0 - 400	100%
		400 - 1,200	90%
		1,200 – 1,600	85%
		1,600 – 2,400	70%

For planning purposes, the Company installed a lower limit of 70% incremental contribution to winter peak before moving to 6-hour storage. In that case, DEC assumed the following incremental contribution to winter peak for 4- and 6-hour storage.

TABLE H-4

INCREMENTAL CONTRIBUTION TO PEAK FOR 6-HOUR STORAGE WITH 4-HOUR ON SYSTEM

SOLAR PENETRATION	DURATION	STORAGE CAPACITY	INCREMENTAL CONTRIBUTION TO WINTER PEAK
High Renew	4-hour	0 - 400	100%
		400 - 800	80%
		800 – 1,200	80%
		1,200 – 1,600	80%
	6-hour	1,600 – 2,000	70%
		2,000 – 2,400	65%

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SOLAR PLUS STORAGE ELCC

The following matrix depicts the range of scenarios evaluated in the ELCC study assuming a 2-hour or 4-hour battery were coupled with solar.

TABLE H-5

SOLAR PLUS STORAGE RUN MATRIX FOR ELCC STUDY

PROJECT MAX CAPACITY (MW)	SOLAR CAPACITY (MW)	TOTAL BATTERY (MW/% OF SOLAR)	REGION EXISTING SOLAR BEFORE ADDING COMBINED PLUS STORAGE PROJECT (MW)
500	500	50 (10%)	2,200
500	500	150 (30%)	2,200
500	500	250 (50%)	2,200
1,000	1,000	100 (10%)	3,200
1,000	1,000	300 (30%)	3,200
1,000	1,000	500 (50%)	3,200

Solar plus storage capacity value was analyzed with 2- and 4-hour battery storage representing 10%, 30%, and 50% of the nameplate solar MW. This evaluation was conducted with 500 and 1,000 MW of solar paired with storage out of 2,700 MW to 4,200 MW of total solar on the DEC system.

The ELCC of standalone storage was determined separately under the following two conditions:

- Economic Arbitrage – Assumes DEC maintains full control of the battery and dispatches the battery based on a daily schedule to maximize economics. This mode of operation allows for the schedule to deviate during emergency events as they occur. Uncertainty in the model is driven by generator outages, day ahead load and solar uncertainty.

- Fixed Dispatch – Assumes DEC has no control of the battery, and the battery charges and discharges against a fixed set of prices. To model this condition, hourly avoided cost values from NC Docket E-100 Sub 158 were used to set the dispatch schedule of the battery. This scenario was developed to demonstrate the impact to storage capacity value if DEC did not have dispatch rights to the storage asset.

The following chart depicts the contribution to winter peak of solar plus storage under the two dispatch modes. The contribution to peak is the contribution of the solar MWs (i.e. a 100 MW solar facility with 25 MW of storage that provides 25% contribution to peak provides 25 MW towards meeting winter peak demand).

FIGURE H-7

AVERAGE CONTRIBUTION TO DEC WINTER PEAK OF SOLAR PLUS 2-HOUR DURATION STORAGE

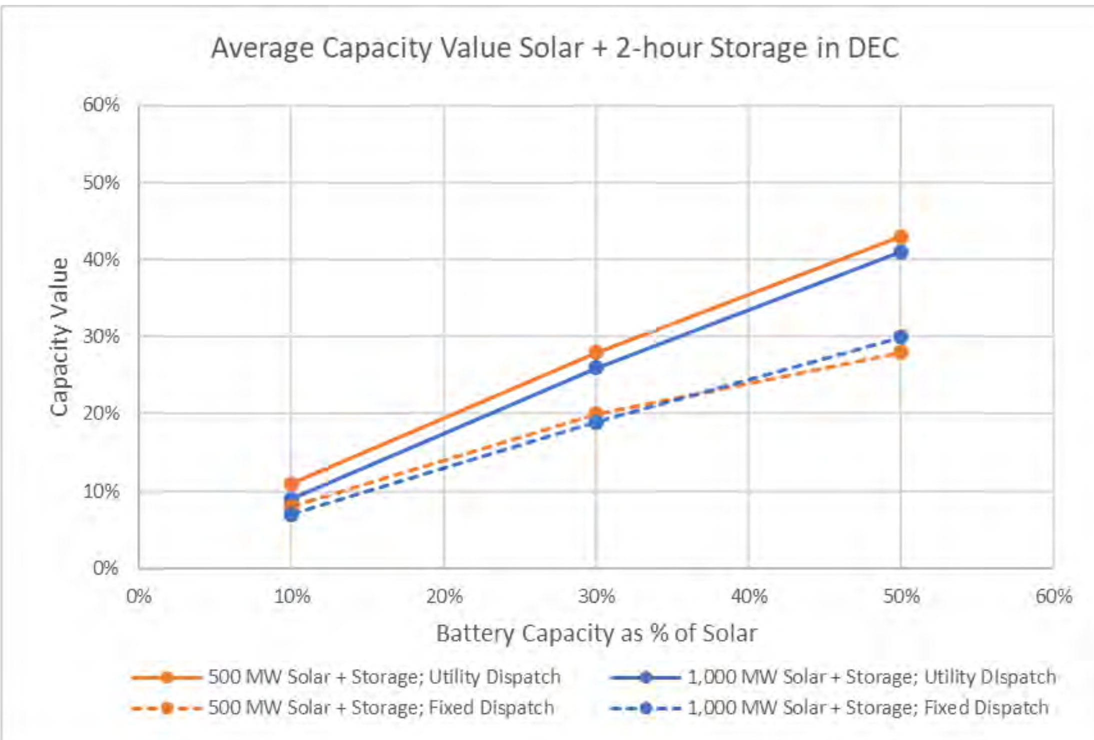

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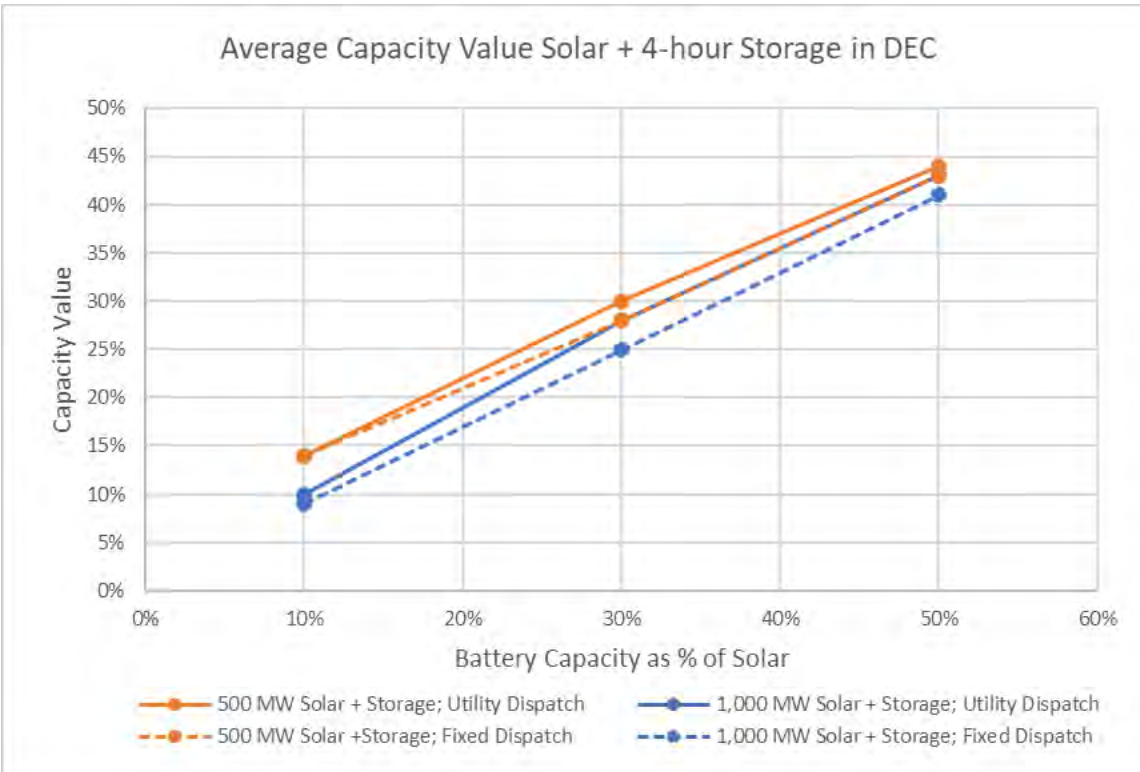
FIGURE H-8

AVERAGE CONTRIBUTION TO DEC WINTER PEAK OF SOLAR PLUS 4-HOUR DURATION STORAGE



Based on the results of the study, and for the same reasons as discussed in the standalone section above, DEC made the following assumptions in development of the 2020 IRP for solar plus storage:

- All solar plus storage capacity values based on Economic Dispatch. The Company will monitor how solar plus storage assets materialize on the system and will adjust this assumption in future IRPs if necessary
- Only 4-hour considered for storage paired with solar

Additionally, for solar paired with storage in DEC, the Company assumed that the capacity of storage was 25% of the nameplate capacity of the solar the storage was paired with. Based on the results of the ELCC study, the Company assumed that this solar plus storage provided 25% of the solar nameplate capacity towards meeting winter peak demand. Also, the solar plus storage projects were capped at the solar capacity, so a 400 MW solar facility paired with 100 MW of battery storage provided a maximum output of 400 MW and was ascribed 100 MW of capacity value.

CONSIDERATIONS FOR FUTURE STUDIES

For some of the portfolios presented in the IRP, specifically the No New Gas Portfolio (Pathway F), and to a lesser extent, the 70% carbon reduction portfolios (Pathways D and E), the level of solar plus storage exceeded the penetration of storage evaluated in the ELCC study. Additionally, in the no new gas portfolios, significant levels of standalone storage would likely deteriorate the capacity value of solar plus storage resources. The combination of standalone storage and solar plus storage was also not evaluated in the ELCC. In all cases, the contribution to winter peak for solar plus storage was assumed to equal the percentage of storage paired with solar. For these reasons, the contribution to winter peak demand of solar plus storage later in the planning horizon is likely overstated. Future storage ELCC studies should evaluate:

- Higher penetrations of solar plus storage
- The impacts of standalone storage on the value of solar plus storage

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ENVIRONMENTAL COMPLIANCE

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APPENDIX I: ENVIRONMENTAL COMPLIANCE

Duke Energy Carolinas, which is subject to the jurisdiction of Federal agencies including the Federal Energy Regulatory Commission, EPA, and the NRC, as well as State commissions and agencies, is potentially impacted by State and Federal legislative and regulatory actions. This section provides a high-level description of several issues Duke Energy Carolinas is actively monitoring or engaged in that could potentially influence the Company's existing generation portfolio and choices for new generation resources.

AIR QUALITY

Duke Energy Carolinas is required to comply with numerous State and Federal air emission regulations, including the federal Acid Rain Program (ARP), the Cross-State Air Pollution Rule (CSAPR) NO_X and SO_2 cap-and-trade program, the Mercury and Air Toxics Standards (MATS) rule, and the 2002 North Carolina Clean Smokestacks Act (NC CSA).

As a result of complying with these regulations, Duke Energy Carolinas reduced SO_2 emissions by approximately 96% from 2000 to 2019 and reduced NOx emissions by approximately 89% from 1997 to 2019. While the NC CSA was instrumental in achieving significant emission reductions to benefit air quality in North Carolina, recent federal regulations now impose more stringent requirements, as noted below.

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

CROSS-STATE AIR POLLUTION RULE (CSAPR)

The "good neighbor" provision of the Clean Air Act requires states in their State Implementation Plans (SIPs) to address interstate transport of air pollution that affects downwind states' ability to attain and maintain National Ambient Air Quality Standards (NAAQS). If states do not submit SIPs or EPA does not approve them, EPA must issue Federal Implementation Plans (FIPs) as a backstop. EPA has created several regulatory programs via the FIP process to address these emissions, including the Clean Air Interstate Rule (CAIR), the Cross-State Air Pollution Rule (CSAPR), and most recently, the CSAPR Update Rule. These programs establish state emission budgets for SO_2 and NOx on an annual basis, and NOx during ozone season (May 1-September 30.)

On September 7, 2016, EPA finalized the CSAPR Update Rule which reduces the ozone season NOx emission budgets from those promulgated in the original CSAPR Rule. The rule also removed North Carolina from CSAPR's ozone season NOx program beginning in 2017. However, Duke Energy units in North Carolina remain subject to annual NOx and SO_2 emission limits.

The Court of Appeals for the District of Columbia Circuit ("D.C. Circuit Court") recently decided environmental and industry challenges to the 2016 CSAPR Update Rule. The Court remanded the rule back to EPA for revision, and Duke expects EPA to issue a proposal addressing the Court's ruling by October 2020. However, EPA's determination that North Carolina sources should be excluded from the CSAPR Update Rule because they do not significantly contribute to downwind ozone non-attainment was not challenged and was not included in the remand from the D.C. Circuit Court.

MERCURY AND AIR TOXICS STANDARDS (MATS) RULE

On February 16, 2012, EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which established emission limits for hazardous air pollutants (HAP) from new and existing coal-fired and oil-fired steam electric generating units. The rule required sources to comply with emission limits by April 16, 2015, or by April 16, 2016 with an approved extension. Duke Energy Carolinas is complying with all rule requirements.

In June 2015, the Supreme Court determined that EPA had unreasonably refused to consider costs when it determined that it was appropriate and necessary to regulate hazardous air pollutants from coal-fired and oil-fired steam electric generating units and remanded the case to the D.C. Circuit Court for further proceedings.

On May 22, 2020, EPA published a final rule and concluded that it is not "appropriate and necessary" to regulate power plant HAP emissions. However, EPA declined to rescind the 2012 MATS rule. In addition, EPA issued the results of its statutorily required Residual Risk and Technology Review (RTR) and determined that no changes to the MATS emission standards are needed.

NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS):

8-HOUR OZONE NAAQS:

In October 2015, EPA finalized revisions to the primary (health-based) and secondary (welfare-based) 8-Hour ozone national ambient air quality standard (NAAQS), lowering them from 75 to 70 parts per billion (ppb.) EPA finalized area designations for the 2015 ozone standard and did not designate any nonattainment areas in North Carolina.

In August 2019, the D.C. Circuit decided challenges from state, environmental, and industry challengers to the 2015 standard. The Court upheld the primary standard but remanded the secondary standard to EPA for "further explanation and reconsideration."

SO_2 NAAQS

On June 22, 2010, EPA finalized revisions to the sulfur dioxide (SO_2) NAAQS, establishing a 1-hour standard of 75 ppb. Based on review of ambient air quality monitoring data or modeled assessment of emission sources, EPA has designated each of the counties surrounding Duke Energy Carolinas facilities as attainment for the SO_2 NAAQS.

On March 8, 2019, after the periodic review required under the Clean Air Act, EPA issued a final rule retaining the SO_2 NAAQS standards, without revision.

FINE PARTICULATE MATTER ($PM_{2.5}$) NAAQS

On December 14, 2012, the EPA finalized revisions to the $PM_{2.5}$ ("fine particle") NAAQS, establishing an annual average standard of 12 micrograms per cubic meter and a 24-hour standard of 35 micrograms per cubic meter. The EPA finalized area designations for this standard in December 2014. That designation process did not result in any areas in North Carolina being designated nonattainment. On April 30, 2020, EPA proposed to retain the standards, without revision.

GREENHOUSE GAS REGULATION

On October 23, 2015, the EPA published a final rule establishing carbon dioxide (CO_2) emissions limits for new, modified and reconstructed power plants. The requirements for new plants apply to plants that commenced construction after January 8, 2014. EPA set an emission standard for new coal units of 1,400 pounds of CO_2 per gross MWh, which would require the application of partial carbon capture and storage (CCS) technology for a coal unit to be able to meet the limit. The EPA set a final standard of 1,000 pounds of CO_2 per gross MWh for new natural gas combined cycle (NGCC) units. Duke Energy Carolinas considers the standard for NGCC units to be achievable.

On December 20, 2018, EPA proposed revised NSPS standards. The proposed emission limit for new and reconstructed coal units is 1,900 pounds of CO_2/MWh, which is intended to reflect what has been demonstrated by the most efficient coal units without the use of CCS. The requirements apply to plants that commenced construction after December 20, 2018. EPA did not propose to change the standard established in 2015 for new or reconstructed natural gas combined-cycle units.

On October 23, 2015, the EPA published the Clean Power Plan (CPP) final rule, regulating CO_2 emissions from existing coal and natural gas units. The CPP established CO_2 emission rates and mass cap goals that apply to existing fossil fuel-fired EGUs. Petitions challenging the rule were filed by numerous groups, and on February 9, 2016, the Supreme Court issued a stay of the final CPP rule, halting its implementation.

On July 8, 2019, EPA finalized the Affordable Clean Energy (ACE) rule, and in a separate but related rule repealed the Clean Power Plan and established CO_2 emission standards for existing coal-fired power plants only. EPA declined to set standards for existing natural gas plants. States have until July 8, 2022, to submit plans based on application of efficiency improvements at existing coal-fired power plants to EPA for approval. Various environmental groups, states, and industry groups have filed petitions for review in the D.C. Circuit challenging the ACE rule, whereas many states and industry groups have intervened on behalf of EPA to defend the rule.

WATER QUALITY AND BY-PRODUCTS ISSUES

CWA 316(B) COOLING WATER INTAKE STRUCTURES

Federal regulations implementing §316(b) of the Clean Water Act (CWA) for existing facilities were published in the Federal Register on August 15, 2014, with an effective date of October 14, 2014. The rule regulates cooling water intake structures at existing facilities to address environmental impacts from fish being impinged (pinned against cooling water intake structures) and entrained (being drawn into cooling water systems and affected by heat, chemicals or physical stress). The final rule establishes aquatic protection requirements at existing facilities and new on-site generation that withdraw 2 million gallons per day (MGD) or more from rivers, streams, lakes, reservoirs, estuaries, oceans, or other waters of the United States. All DEC nuclear fueled, coal-fired and combined cycle stations in South Carolina and North Carolina are affected sources.

The rule establishes two standards, one for impingement and one for entrainment. To demonstrate compliance with the impingement standard, facilities must choose and implement one of the following options:

- Closed cycle re-circulating cooling system; or
- Demonstrate the maximum design through screen velocity is less than 0.5 feet per second (fps) under all conditions; or
- Demonstrate the actual through screen velocity, based on measurement, is less than 0.5 fps; or
- Install modified traveling water screens and optimize performance through a two-year study; or
- Demonstrate a system of technologies, practices, and operational measures are optimized to reduce impingement mortality; or
- Demonstrate the impingement latent mortality is reduced to no more than 24% annually based on monthly monitoring.

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

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

The rule requires facilities to submit all necessary 316(b) reports in accordance with its Clean Water Act (CWA) discharge permit and schedule developed by the state permitting agency. Duke expects the state permitting authority to determine necessary controls for the affected DEC facilities in the 2020 to 2023 timeframe and intake modifications, if necessary, to be required in the 2022 to 2026 timeframe.

STEAM ELECTRIC EFFLUENT GUIDELINES

Federal regulations revising the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category ("ELG Rule") were published in the Federal Register on November 3, 2015, with an effective date of January 4, 2016. While the ELG Rule is applicable to all steam electric generating units, waste streams affected by these revisions are generated at DEC's existing coal-fired facilities. The revisions prohibit the discharge of bottom and fly ash transport water, and flue gas mercury control wastewater, and establish technology-based limits on the discharge of wastewater generated by Flue Gas Desulfurization (FGD) systems, and leachate from coal combustion residual (CCR) landfills and impoundments. The rule also establishes technology-based limits on gasification wastewater, but this waste stream is not generated at any of the DEC facilities. Affected facilities must comply between 2018 and 2023, depending on timing of its Clean Water Act (CWA) discharge permit.[1]

[1] On September 12, 2017, EPA finalized a rule ("the Postponement Rule") to postpone the earliest compliance date for bottom ash transport water and FGD wastewater for a period of two years (i.e. November 1, 2020), but this rule did not extend the latest compliance date of Dec. 31, 2023 and did not revise the earliest compliance date for fly ash transport water. The Postponement Rule was subsequently upheld by the Fifth Circuit Court of Appeals on August 28, 2019.

Petitions challenging the rule were filed by several groups and all challenges to the rule were consolidated in the Fifth Circuit Court of Appeals. On August 11, 2017, the EPA Administrator signed a letter announcing his decision to conduct a rulemaking to consider revising the new, more stringent effluent limitations and pretreatment standards for existing sources in the final rule that apply only to bottom ash transport water and FGD wastewater. On August 22, 2017, the Fifth Circuit Court of Appeals granted EPA's Motion to Govern Further Proceedings, thereby severing and suspending the claims related to flue gas desulfurization wastewater, bottom ash transport water and gasification wastewater. Subsequently, challenges to the limits for fly ash transport water and gasification wastewater were voluntarily dismissed while litigation on the limits for legacy wastewater and CCR leachate continued.

On April 12, 2019, the Fifth Circuit vacated and remanded portions of the rule dealing with legacy wastewater and CCR leachate. It is unknown when EPA will propose new limits for these waste streams.

The proposed rule revising the more stringent effluent limitations and pretreatment standards for bottom ash transport water and FGD wastewater was published on November 22, 2019. The public comment period ended on January 21, 2020. The rule is anticipated to be finalized in 3rd quarter 2020.

All DEC coal-fired units have installed technologies to prohibit the discharge of fly ash transport water and to either eliminate the generation of bottom ash transport water or recirculate bottom ash transport water in a closed-loop system. Necessary upgrades or new FGD wastewater treatment systems have been installed at all affected DEC coal-fired units except for Rogers (Cliffside) Unit 5. Construction of the FGD wastewater treatment system at the Rogers (Cliffside) Unit 5 is in progress and expected to be completed by 4th quarter 2021. The anticipated final rule revising the more stringent effluent limitations and pretreatment standards for bottom ash transport water and FGD wastewater is not expected to require the installation of any additional technology.

COAL COMBUSTION RESIDUALS

In January 2009, following Tennessee Valley Authority's Kingston ash pond dike failure, Congress issued a mandate to EPA to develop federal regulations for the disposal of coal combustion residuals (CCR). CCR includes fly ash, bottom ash, boiler slag, and flue gas desulfurization solids. On April 17, 2015, EPA finalized the first federal regulations for the disposal of CCR. The 2015 CCR rule regulates CCR as a nonhazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA) and allows for beneficial use of CCR with some restrictions.

The 2015 CCR rule applies to all new and existing landfills, new and existing surface impoundments that were still receiving CCR as of the effective date of the rule, and existing surface impoundments that were no longer receiving CCR but contained liquids as of the effective date of the rule, provided these units were located at stations generating electricity (regardless of fuel source) as of the effective date of the rule. The rule establishes national minimum criteria that include location restrictions, design standards, structural integrity criteria, groundwater monitoring and corrective action, closure and post-closure care requirements, and recordkeeping, reporting, and other operational procedures to ensure the safe management and disposal of CCR.

The 2015 CCR rule was challenged in litigation by industry and environmental petitioners. In August 2018, the D.C. Circuit Court vacated provisions that allowed unlined and clay-lined impoundments to continue to operate, finding those provisions violated the RCRA protectiveness standard. In response to the D.C. Circuit decision, EPA proposed two rulemakings to address unlined impoundments. The "Part A" rule, which was proposed on December 2, 2019, would establish an August 31, 2020 deadline to cease placement of CCR and non-CCR wastestreams into unlined ash basins and initiate closure (although that date is expected to be moved back in the final rule.)

The "Part B" rule, which was proposed on March 3, 2020, would establish a process for owners/operators to make an alternate liner demonstration. The proposal also included other significant provisions, including EPA's reiteration of its view that the use of CCR in units subject to forced closure is prohibited under the current CCR regulations. However, EPA proposed two options for allowing the use of CCR in surface impoundments and landfills for the purpose of supporting closure. In addition, EPA proposed a new closure-by-removal option, which would allow owners/operators to complete groundwater corrective action during the post-closure care period.

In February 2020, EPA published a proposed rule to establish a federal permitting program for CCR surface impoundments and landfills in states that do not have approved state permit programs, as provided under the 2016 WIIN Act. Only Oklahoma and Georgia currently have approved state programs, so this rule would apply in North Carolina until such a time that a state CCR permit program is approved by EPA.

In August 2019, EPA proposed amendments addressing CCR storage and criteria for unencapsulated beneficial uses that would require CCR storage piles to be completely enclosed (four walls and a roof), or would require control of releases and demonstration that the accumulation is "temporary" and that all CCR will be removed at some point in the future. EPA also proposed replacing the mass-based threshold for unencapsulated non-roadway beneficial uses to location-based criteria based on landfill location restrictions.

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

CAMA establishes requirements regarding the beneficial use of CCR, the closure of existing CCR surface impoundments, the disposal of CCR at active coal plants, and the handling of surface and groundwater impacts from CCR surface impoundments. CAMA required eight "high-priority" CCR surface impoundments in North Carolina to be closed no later than December 31, 2019 (although that date was subsequently extended to August 1, 2022, for the two Asheville Station impoundments.) CAMA also required state regulators to provide risk-ranking classifications to determine the method and timing for closure of the remaining CCR surface impoundments. The North Carolina Department of Environmental Quality (NCDEQ) categorized all remaining CCR surface impoundments as low-risk after Duke Energy completed required dam safety repairs and established alternate permanent replacement water supplies for landowners with drinking water supply wells within a one-half-mile radius of CCR surface impoundments. Despite Duke Energy having taken these measures, on April 1, 2019, NCDEQ ordered that all remaining CCR surface impoundments in the state be closed by removal of CCR.

J

NON-UTILITY GENERATION AND WHOLESALE

Corrected 11.06.2020

APPENDIX J: NON-UTILITY GENERATION AND WHOLESALE

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

TABLE J-1:

DEC AGGREGATED WHOLESALE SALES CONTRACTS

DEC AGGREGATED WHOLESALE SALES CONTRACTS								
WINTER COMMITMENT (MW)								
2020	2021	2022	2023	2024	2025	2026	2027	2028
2,146	2,076	2,028	2,044	2,061	2,078	2,093	2,107	2,124

NOTES:

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

TABLE J-2:

FIRM WHOLESALE PURCHASE POWER CONTRACTS

PURCHASED POWER CONTRACT	SUMMER CAPACITY (MW)	LOCATION	VOLUME OF PURCHASES (MWH)
			JUL 19-JUN 20
Peaking / Fuel Oil	21	NC	21,288
Peaking / Gas	91	NC/SC	463,408
Peaking / Hydro	11	GA/AL/SC	29,721
Base / Nuclear	51	NC	448,704
System	7	NC	43,068

NOTES: Data represented above represents contractual agreements. These resources may be modeled differently in the IRP.

Corrected 11.06.2020

NON-UTILITY GENERATION FACILITIES – NORTH CAROLINA

Please refer to DEC and DEP Small Generator Interconnection Consolidated Annual Reports filed on March 12, 2020 in NCUC Docket No. E-100, Sub 113B for details on the DEC North Carolina NUGS. The DEC NUG facilities are comprised of 99% intermediate facilities while the remaining 1% represents baseload facilities. Currently, hydro is considered baseload, solar and other renewables are considered intermediate.

Please refer to Table J-3 DEC Non-Utility Generator Listing – North Carolina Facilities.

NON-UTILITY GENERATION FACILITIES – SOUTH CAROLINA

Table J-4 contains non-utility generation contracts for facilities located in South Carolina.

Please refer to the attachment, Table J-4 DEC Non-Utility Generator Listing – South Carolina Facilities.

DEC QF
INTERCONNECTION QUEUE

Corrected 11.06.2020

APPENDIX K: DEC QF INTERCONNECTION QUEUE

Qualified Facilities contribute to the current and future resource mix of the Company. QFs that are under contract are captured as designated resources in the base resource plan. QFs that are not yet under contract but in the interconnection queue may contribute to the undesignated additions identified in the resource plans. It is not possible to precisely estimate how much of the interconnection queue will come to fruition however the current queue clearly supports solar generation's central role in DEC's NC REPS compliance plan and HB 589.

Below is a summary of the interconnection queue as of July 31, 2020:

TABLE K-1
DEC QF INTERCONNECTION QUEUE

UTILITY	FACILITY STATE	ENERGY SOURCE TYPE	NUMBER OF PENDING PROJECTS	PENDING CAPACITY (MW AC)
DEC	NC	Battery	2	7
		Solar	95	2,365
	NC Total		97	2,372
	SC	Battery	2	14
		Hydroelectric	1	320
		Solar	138	2,676
	SC Total		141	3,010
	DEC Total		238	5,383

NOTE: (1) Above table includes all QF projects that are in various phases of the interconnection queue and not yet generating energy.

(2) Table does not include net metering interconnection requests.

TRANSMISSION PLANNED OR UNDER CONSTRUCTION

Corrected 11.06.2020

APPENDIX L: TRANSMISSION PLANNED OR UNDER CONSTRUCTION

In this section, DEC provide details on transmission projects planned or under construction, as well as how DEC ensures transmission system adequacy.

DEC IN-SERVICE TRANSMISSION

Table L-1 below reflects Duke Energy Carolinas installed transmission circuit miles at each voltage class.

TABLE L-1
DEC INSTALLED TRANSMISSION CIRCUIT MILES BY VOLTAGE CLASS

CIRCUIT VOLTAGE	44 KV	66-69 KV	100 - 199 KV	230 KV	345 KV	500+ KV
Duke Energy Carolinas	2,636	109	6,465	2,574		577

DEC TRANSMISSION PLANNED OR UNDER CONSTRUCTION

This section lists the planned transmission line additions. A discussion of the adequacy of DEC's transmission system is also included. Table L-2 lists the transmission line projects planned to meet reliability needs. This section also provides other information pursuant to the North Carolina and South Carolina rules.

TABLE L-2
DEC TRANSMISSION LINE ADDITIONS

	LOCATION		CAPACITY	VOLTAGE	
YEAR	FROM	TO	MVA	KV	COMMENTS
None					

Corrected 11.06.2020

CECPCN / CPCN

Certificates of environmental compatibility and public convenience and necessity (CECPCN) for the construction of electric transmission lines in South Carolina and Certificates of Public Convenience and Necessity (CPCN) in North Carolina

(p) Plans for the construction of transmission lines in North Carolina and South Carolina (161 kV and above) shall be incorporated in filings made pursuant to applicable rules. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(1) For existing lines, the information required on FERC Form 1, pages 422, 423, 424, and 425, except that the information reported on pages 422 and 423 may be reported every five years.

Please refer to the Company's FERC Form No. 1 filed with FERC in April 2020.

(p) Plans for the construction of transmission lines in North Carolina and South Carolina (161 kV and above) shall be incorporated in filings made pursuant to applicable rules. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(2) For lines under construction, the following:

a. Commission docket number;
b. Location of end point(s);
c. Length;
d. Range of right-of-way width;
e. Range of tower heights;
f. Number of circuits;
g. Operating voltage;
h. Design capacity;
i. Date construction started;
j. Projected in-service date;

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

DEC TRANSMISSION SYSTEM ADEQUACY

Duke Energy Carolinas monitors the adequacy and reliability of its transmission system and interconnections through internal analysis and participation in regional reliability groups. Internal transmission planning looks 10 years ahead at projected generating resources and projected load to identify transmission system upgrade and expansion requirements. Corrective actions are planned and implemented in advance to ensure continued cost-effective and high-quality service. The DEC transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability. DEC works with DEP, North Carolina Electric Membership Corporation (NCEMC) and ElectriCities to develop an annual NC Transmission Planning Collaborative (NCTPC) plan for the DEC and DEP systems in both North and South Carolina. In addition, transmission planning coordinates with neighboring systems including Dominion Energy South Carolina Inc. (DESC; formerly SCE&G) and Santee Cooper under a number of mechanisms including legacy interchange agreements between DESC, Santee Cooper, DEP, and DEC.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with DEC's Transmission Planning Guidelines for voltage and thermal loading. The annual screening uses methods that comply with SERC Reliability Corporation (SERC) policy and North American Electric Reliability Corporation (NERC) Reliability Standards and the screening results identify the need for future transmission system expansion and upgrades. The transmission system is planned to ensure that there are no equipment overloads and adequate voltage is maintained to provide reliable service. The most stressful scenario is typically at projected peak load with selected 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. DEC currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Guidelines and the 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 FERC Large and Small Generator Interconnection Procedures in the OATT and related North Carolina and South

Carolina state procedures. It should be noted that location, MW interconnection requested, resource/load characteristics, and prior queued requests, in aggregate can have wide ranging impacts on transmission network upgrades required to reliably accommodate the interconnection request. In addition, the actual costs for the associated network upgrades are dependent on escalating labor and materials costs. Based on recent realized cost from implementing transmission projects, the escalation of labor and materials costs in future years could be significant.

SERC audits DEC every three years for compliance with NERC Reliability Standards. Specifically, the audit requires DEC to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the Company's annual compliance filing certifications. SERC conducted a NERC Reliability Standards compliance audit of DEC in June 2019. The scope of this audit included standards impacting the Transmission Planning area. DEC received "No Findings" from the audit team in the areas associated with Transmission Planning activities.

DEC participates in several regional reliability groups to coordinate analysis of regional, sub-regional and inter-balancing authority area transfer capability and interconnection reliability. The reliability groups' reliability purposes are 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 future periods. The groups also perform computer simulation tests for high transfer levels to verify satisfactory transfer capability. Application of the practices and procedures described above ensures that DEC's transmission system continues to provide reliable service to its native load and firm transmission customers.

ECONOMIC DEVELOPMENT

Corrected 11.06.2020

APPENDIX M: ECONOMIC DEVELOPMENT

CUSTOMERS SERVED UNDER ECONOMIC DEVELOPMENT

In the NCUC Order issued in Docket No. E-100, Sub 73 dated November 28, 1994, the NCUC ordered North Carolina utilities to review the combined effects of existing economic development rates within the approved IRP process and file the results in its short-term action plan. The incremental load (demand) for which customers are receiving credits under economic development rates and/or self-generation deferral rates (Rider EC), as well as economic redevelopment rates (Rider ER) as of June 2020 is:

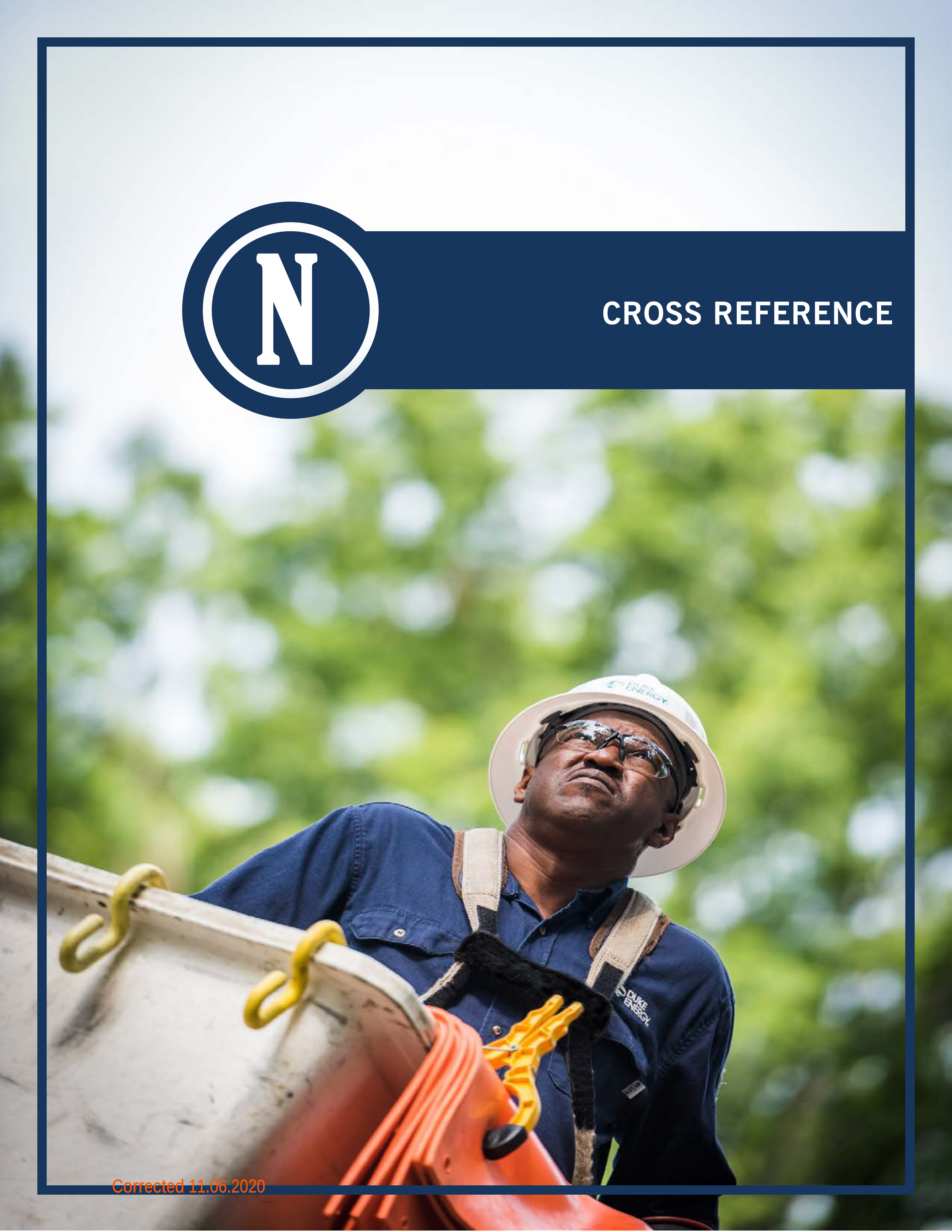
RIDER EC

145 MW for North Carolina
131 MW for South Carolina

RIDER ER

41 MW for North Carolina
0 MW for South Carolina

CROSS REFERENCE



Corrected 11.06.2020

TABLE N-1

CROSS REFERENCE - NC R8-60 REQUIREMENTS

REQUIREMENT	REFERENCE	LOCATION
15-year Forecast of Load, Capacity and Reserves	NC R8-60 (c) 1	Chapter 3 Appendix C
Comprehensive analysis of all resource options	NC R8-60 (c) 2	Chapter 8 Chapter 12 Appendix A Appendix G
Assessment of Purchased Power	NC R8-60 (d)	Chapter 12 Appendix A Appendix J Attachment II
Assessment of Alternative Supply-Side Energy Resources	NC R8-60 (e)	Chapter 8 Appendix G
Assessment of Demand-Side Management	NC R8-60 (f)	Chapter 4 Appendix D Attachment V
Evaluation of Resource Options	NC R8-60 (g)	Chapter 5 Chapter 8 Appendix A Appendix D Appendix G
Short-Term Action Plan	NC R8-60 (h) 3	Chapter 14
REPS Compliance Plan	NC R8-60 (h) 4	Attachment I
Forecasts of Load, Supply-Side Resources, and Demand-Side Resources * 10-year History of Customers and Energy Sales * 15-year Forecast w & w/o Energy Efficiency * Description of Supply-Side Resources	NC R8-60 (i) 1(i) NC R8-60 (i) 1(ii) NC R8-60 (i) 1(iii)	Chapter 3 Chapter 4 Appendix C Appendix D Attachment V

TABLE N-1

CROSS REFERENCE - NC R8-60 REQUIREMENTS (CONT.)

REQUIREMENT	REFERENCE	LOCATION
Generating Facilities * Existing Generation * Planned Generation * Non-Utility Generation	NC R8-60 (i) 2(i) NC R8-60 (i) 2(ii) NC R8-60 (i) 2(iii)	Chapter 2 Chapter 12 Appendix B Appendix J
Reserve Margins	NC R8-60 (i) 3	Chapter 9 Chapter 12 Attachment III
Wholesale Contracts for the Purchase and Sale of Power * Wholesale Purchased Power Contracts * Request for Proposal * Wholesale Power Sales Contracts	NC R8-60 (i) 4(i) NC R8-60 (i) 4(ii) NC R8-60 (i) 4(iii)	Chapter 12 Chapter 14 Appendix A Appendix J
Transmission Facilities	NC R8-60 (i) 5	Chapter 7 Appendix L
Energy Efficiency and Demand-Side Management * Existing Programs * Future Programs * Rejected Programs * Consumer Education Programs	NC R8-60 (i) 6(i) NC R8-60 (i) 6(ii) NC R8-60 (i) 4(iii) NC R8-60 (i) 4(iv)	Chapter 4 Appendix D Attachment V
Assessment of Alternative Supply-Side Energy Resources * Current and Future Alternative Supply-Side Resources * Rejected Alternative Supply-Side Resources	NC R8-60 (i) 7(i) NC R8-60 (i) 7(ii)	Chapter 8 Appendix A Appendix G
Evaluation of Resource Options (Quantitative Analysis)	NC R8-60 (i) 8	Appendix A
Levelized Bus-bar Costs	NC R8-60 (i) 9	Appendix G
Smart Grid Impacts	NC R8-60 (i) 10	Appendix D
Legislative and Regulatory Issues		Appendix I
Greenhouse Gas Reduction Compliance Plan		Chapter 16 Appendix A
Other Information (Economic Development)		Appendix M
NCUC Subsequent Orders		Table N-3

TABLE N-2

CROSS REFERENCE – SC ACT 62 REQUIREMENTS

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Each electrical utility must submit its integrated resource plan to the commission. The integrated resource plan must be posted on the electrical utility's website and on the commission's website.	Part (C)(2)	Post - filing
a long-term forecast of the utility's sales and peak demand under various reasonable scenarios;	Part (C)(2)	Chapter 3 Appendix A Appendix C
The type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;	Part (C)(2)	Chapter 8 Appendix A Appendix F Appendix G
projected energy purchased or produced by the utility from a renewable energy resource;	Part (C)(2)	Chapter 5 Chapter 12 Appendix A Appendix E Appendix J Appendix N (DEP)
a summary of the electrical transmission investments planned by the utility;	Part (C)(2)	Chapter 7 Appendix A Appendix L

TABLE N-2
CROSS REFERENCE – SC ACT 62 REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following: (i)customer energy efficiency and demand response programs; (ii)facility retirement assumptions; and (iii)sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;	Part (C)(2)	Chapter 3 Chapter 4 Chapter 12 Appendix A Appendix B Appendix C Appendix D Appendix I
data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;	Part (C)(2)	Chapter 2 Appendix B
plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan	Part (C)(2)	Chapter 7 Chapter 12 Chapter 13 Chapter 14 Chapter 15 Chapter 16 Appendix A

TABLE N-2

CROSS REFERENCE – SC ACT 62 REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs	Part (C)(2)	Chapter 7 Chapter 8 Chapter 12 Chapter 13 Chapter 14 Chapter 15 Chapter 16 Appendix A Appendix G
a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.	Part (C)(2)	Chapter 3 Chapter 4 Appendix C Appendix D
An integrated resource plan may include distribution resource plans or integrated system operation plans.	Part (C)(2)	Chapter 7 Chapter 11 Chapter 15 Appendix A Appendix L

TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The two Base Case Plans (i.e. Base CO2 Future and Base No CO2 Future) … encourages the Companies to carry forward both alternatives for their next IRPs due for 2020."	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 12 Appendix A
DEC and DEP present one or more alternative resource portfolios which show that the remainder of each Company's existing coal-fired generating units are retired by the earliest practicable date. The "earliest practicable date" shall be identified based on reasonable assumptions and best available current knowledge concerning the implementation considerations and challenges identified. In the IRPs the Companies shall explicitly identify all material assumptions, the procedures used to validate such assumptions, and all material sensitivities relating to those assumptions. The Companies shall include an analysis that compares the alternative scenario(s) to the Base Case with respect to resource adequacy, long-term system costs, and operational and environmental performance.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 11 Appendix A Appendix I

TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The Commission expects that the “earliest practicable date” chosen by the Companies when developing their alternative portfolio(s) and the replacement resources included in the portfolio(s) should reflect the transmission and distribution infrastructure investments that will be required to make a successful transition. The Companies should also attempt to identify – with as much specificity as is possible in the circumstances - all major transmission and distribution upgrades that will be required to support the alternative resource portfolio(s) along with the best current estimate of costs of constructing and operating such upgrades.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 7 Chapter 11 Appendix A Appendix L
The Companies should note that the directive in this order supplements and does not supersede the directive in the Commission’s August 27, 2019 Order in this docket (at p. 31), requiring that the Companies in preparing and modeling their Base Case plans remove any assumption that existing coal-fired units will be operated for the remainder of their depreciable lives and, instead, include such existing assets in the Base Case resource portfolio only if warranted under least cost planning principles. In this Order the Commission’s directive that the Companies present one or more “earliest practicable date” retirement portfolios is not constrained by least cost principles, and the Companies will be expected to discuss cost differences, if any, between such alternatives portfolios and the resource portfolios selected for their Base Cases.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20 E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 11 Appendix A

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TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Updated resource adequacy studies be filed along with the Companies' 2020 IRPs, together with all supporting exhibits, attachments and appendices subject to such confidentiality designations as the Companies deem warranted.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	IRP Filing Letters Chapter 9 Attachment III
In documenting the updated Resource Adequacy Study for 2020, the Companies should provide additional detail and support for both the study inputs and outputs.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The Commission will direct DEC and DEP to more fully explain and detail the study results.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The updated Resource Adequacy Study should provide additional clarity around outputs… At a minimum the Commission finds it helpful for results to be displayed in a graphic that clearly shows the various components to the Total System Costs such as included in the "Bathtub Curves."	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The Commission directs the updated Resource Adequacy studies to address the sensitivity of modeling inputs such as Equivalent Forced Outage Rates (EFOR).	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III

TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The Companies to continue to involve stakeholders in a meaningful way as the ISOP process advances. In particular, the Commission recognizes that there could be significant benefits to involving North Carolina's electric membership cooperatives and municipally owned and operated electric utilities in this effort.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Executive Summary Chapter 15
The 2020 IRPs should continue to report on the progress of the ISOP effort. As a minimum, the IRPs should communicate with some specificity the project plan and dates for the ISOP effort. In addition, the Commission will direct the utilities to discuss the expected outputs of the ISOP process and how they will be utilized in the IRP process.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 15
The Commission determines that the "First Resource Need" section of DEC's and DEP's 2019 IRPs is an appropriate output of the integrated resource planning processes and adequate to support future avoided cost calculations.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 13
Demonstrate assessments of the benefits of purchased power solicitations, alternative supply side resources, potential DSM/EE programs, and a comprehensive set of potential resource options and combinations of resource options, as required by Commission Rule R8-60(d), (e), (f) and (g), including:	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 3 Chapter 4 Chapter 8 Chapter 12 Appendix A Appendix D Appendix G Appendix J

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TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
A detailed discussion and work plan for how Duke plans to address the 1,200 MW of expiring purchased power contracts at DEP and 124 MW at DEC.	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 12 Chapter 14 Appendix A Appendix J
A discussion of the following statement: "The Companies' analysis of their capacity and energy needs focuses on new resource selection while failing to evaluate other possible futures for existing resources. As part of the development of the IRPs, the Companies conducted a quantitative analysis of the resource options available to meet customers' future energy needs. This analysis intended to produce a base case through a least cost analysis where each company's system was optimized independently. However, the modeling exercise fails to consider whether existing resources can be cost effectively replaced with new resources. Therefore, Duke has not performed a least-cost analysis to design its recommended plans."	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Chapter 12 Chapter 16 Appendix A
(d) A stand-alone analysis of the cost effectiveness of a substantial increase in EE and DSM, rather than the combined modeling of EE and high renewables included in DEC's and DEP's Portfolio 5 in their 2018 IRPs.	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Appendix A Appendix D

TABLE N-3
CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Provide a discussion of the advantages and disadvantages of periodically issuing “all resources” RFPs in order to evaluate least-cost resources (both existing and new) needed to serve load	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
Include information, analyses, and modeling regarding economic retirement of coal-fired units	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
Model continued operation under least cost principles in competition with alternative new resources	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A

TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
If continued operation until fully depreciated is least cost alternative, shall separately model an alternative scenario premised on advanced retirement of one or more of such units (including an analysis of the difference in cost from the base case and preferred case scenarios.)	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
Future IRP filings by all IOUs shall continue to include a detailed explanation of the basis and justification for the appropriateness of the level of the respective utility's projected reserve margins.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 4	Chapter 9 Attachment III
Future IRP filings by all IOUs shall continue to include a copy of the most recently completed FERC Form 715, including all attachments and exhibits.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 5	Filed Under Seal
IOUs should continue to monitor and report any changes of more than 10% in the energy and capacity savings derived from DSM and EE between successive IRPs, and evaluate and discuss any changes on a program-specific basis. Any issues impacting program deployment should be thoroughly explained and quantified in future IRPs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 7	Appendix D

TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Each IOU shall continue to include a discussion of the status of EE market potential studies or updates in their future IRPs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 8 E-100, Sub 128, Order Approving 2011 Annual Updates to 2010 IRPs and 2011 REPS Compliance Plans, dated 5/30/12, ordering paragraph 9	Appendix D Attachment V
All IOUs shall include in future IRPs a full discussion of the drivers of each class' load forecast, including new or changed demand of a particular sector or sub-group.	E-100, Sub 141, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/26/15, ordering paragraph 9 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 9 E-100, Sub 133, Order Denying Rulemaking Petition (Allocation Methods), dated 10/30/12, ordering paragraph 4	Chapter 3 Appendix C

TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Future IRP filings by DEP and DEC shall continue to provide information on the number, resource type and total capacity of the facilities currently within the respective utility's interconnection queue as well as a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 14 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 14	Chapter 5 Appendix E Appendix K
Duke plans to diligently review the business case for relicensing existing nuclear units, and if relicensing is in the best interest of customers, pursue second license renewal.	No new reporting requirements, but NCUC stated its expectation that Duke would make additional changes to future IRPs as discussed in Duke's 4/20/15 reply comments (p. 7) in E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15 (p. 39)	Chapter 10

TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Duke will include Li-ion battery storage technology in the economic supply-side screening process as part of the IRP.	No new reporting requirements, but NCUC stated its expectation that Duke would make additional changes to future IRPs as discussed in Duke's 4/20/15 reply comments (p. 19) in E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15 (p. 39)	Chapter 6 Chapter 8 Chapter 12 Appendix A Appendix G Appendix H
DEP will incorporate into future IRPs any demand and energy savings resulting from the Energy Efficiency Education Program, My Home Energy Report Program, Multi-Family Energy Efficiency Program, Small Business Energy Saver Program, and Residential New Construction Program.	E-2, Sub 1060, Order Approving Program, dated 12/18/14, p. 2 E-2, Sub 989, Order Approving Program, dated 12/18/14, p. 3 E-2, Sub 1059, Order Approving Program, dated 12/18/14, p. 2 E-2, Sub 1022, Order Approving Program, dated 11/5/12, footnote 2 (Small Business Energy Saver) E-2, Sub 1021, Order Approving Program, dated 10/2/12, footnote 3 (Residential New Construction Program)	Appendix D

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TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
To the extent an IOU selects a preferred resource scenario based on fuel diversity, the IOU should provide additional support for its decision based on the costs and benefits of alternatives to achieve the same goals.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 13 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 13 E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 16	Chapter 8 Appendix A Appendix F Appendix G
DEC and DEP should consider additional resource scenarios that include larger amounts of renewable energy resources similar to DNCP's Renewable Plan, and to the extent those scenarios are not selected, discuss why the scenario was not selected.	E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 15	Chapter 5 Appendix A Appendix E Appendix N (DEP)
DEP, DEC and DNCP shall annually review their REPS compliance plans from four years earlier and disclose any redacted information that is no longer a trade secret.	E-100, Sub 137, Order Granting in Part and Denying in Part Motion for Disclosure, dated 6/3/13, ordering paragraph 3	Attachment I

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TABLE N-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
[2013] Duke shall show the peak demand and energy savings impacts of each measure/option in the Program separately from each other, and separately from the impacts of its other existing PowerShare DSM program options in its future IRP and DSM filings, and in its evaluation, measurement, and verification reports for each measure of the Program.	E-7, Sub 953, Order Approving Amended Program, dated 1/24/13, ordering paragraph 4 (PowerShare Call Option Nonresidential Load and Curtailment Program)	Appendix D
Each utility shall include in each biennial report potential impacts of smart grid technology on resource planning and load forecasting: a present and five-year outlook – see R8-60(i)(10).	E-100, Sub 126, Order Amending Commission Rule R8-60 and Adopting Commission Rule R8-60.1, dated 4/11/12	Chapter 14 Appendix D

GLOSSARY OF TERMS

10 CFR	Title 10 of the Code of Federal Regulations
AC or A/C	Alternating Current
ACE	Affordable Clean Energy
ACP	Atlantic Coast Pipeline
ACT 62	South Carolina Act 62
ADP	Advanced Distribution Planning
AEO	Annual Energy Outlook
AGC	Automatic Generator Control
AMI	Advanced Metering Infrastructure
APS	Arizona Public Service Electric
ARP	Acid Rain Program
ARPA-E	Advanced Resource Projects Agency-Energy
ASOS	National Weather Service Automated Surface Observing System
BHPCC	Blue Horizons Project Community Council (DEP)
BCFD	Billion Cubic Feet Per Day
BFB	Bubbling Fluidized Bed
BOEM	Bureau of Ocean Energy Management
BYOT	Bring Your Own Thermostat
CAES	Compressed Air Energy Storage
CAIR	Clean Air Interstate Rule
CAMA	North Carolina Coal Ash Management Act of 2014
CAMR	Clean Air Mercury Rule
CAPP	Central Appalachian Coal
CC	Combined Cycle
CCR	Coal Combustion Residuals Rule
CCS	Carbon Capture and Sequestration (Carbon Capture and Storage)
CCUS	Carbon Capture, Utilization and Storage
CECPCN	Certificate of Environmental Compatibility and Public Convenience and Necessity (SC)
CEP	Comprehensive Energy Planning
CES	Clean Electricity Standard
CFL	Compact Fluorescent Light bulbs
CHP	Combined Heat and Power

GLOSSARY OF TERMS (CONT.)

CO_2	Carbon Dioxide
COD	Commercial Operation Date
COL	Combined Construction and Operating License
COVID-19	Coronavirus 2019
COWICS	Carolinas Offshore Wind Integration Case Study
CPCN	Certificate of Public Convenience and Necessity (NC)
CPP	Clean Power Plan
CPRE	Competitive Procurement of Renewable Energy
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
CVR	Conservation Voltage Reduction
CWA	Clean Water Act
DC	Direct Current
DCA	Design Certification Application
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEI	Duke Energy Indiana
DEK	Duke Energy Kentucky
DEP	Duke Energy Progress
DER	Distributed Energy Resource
DER	Duke Energy Renewables
DESC	Dominion Energy South Carolina, Inc. (formerly SCE&G)
DIY	Do It Yourself
DMS	Distribution Management System
DoD	Depth of Discharge
DOE	Department of Energy
DOJ	Department of Justice
DOM	Dominion Zone within PJM RTO
DR	Demand Response
DSCADA	Distribution Supervisory Control and Data Acquisition
DSDR	Distribution System Demand Response Program
DSM	Demand-Side Management

GLOSSARY OF TERMS (CONT.)

EC or Rider EC	Receiving Credits under Economic Development Rates and/or Self-Generation deferral rate
EE	Energy Efficiency
EGU	Electric Generating Unit
EIA	Energy Information Administration
EITF	Energy Innovation Task Force
ELCC	Effective Load Carrying Capability
ELG Rule	Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction Contractors
EPRI	Electric Power Research Institute
ER or Rider ER	Receiving Credits under Economic Re-Development Rates
ESG	Environmental, Social and Corporate Governance
ET	Electric Transportation
EVs	Electric Vehicles
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FLG	Federal Loan Guarantee
FPS	Feet Per Second
FRCC	Florida Reliability Coordinating Council, Inc.
FSO	Fuels and System Optimization
FT Solar	Fixed-tilt Solar
GALL-SLR	Generic Aging Lessons Learned for Subsequent License Renewal
GA-AL-SC	Georgia-Alabama-South Carolina
GHG	Greenhouse Gas
GIP	Grid Improvement Plan
GTI	Gas Technology Institute
GW	Gigawatt
GWh	Gigawatt-hour
HAP	Hazardous Air Pollutants
HB 589	North Carolina House Bill 589
HRSG	Heat Recovery Steam Generator

GLOSSARY OF TERMS (CONT.)

HVAC	Heating, Ventilation and Air Conditioning
IA	Interconnection Agreement
IESO	Independent Electricity System Operator
IGCC	Integrated Gasification Combined Cycle
ILB	Illinois Basin
ILR	Inverter Load Ratios
IPI	Industrial Production Index
IRP	Integrated Resource Plan
IS	Interruptible Service
ISO-NE	ISO New England, Inc.
ISOP	Integrated Systems and Operations Planning
IT	Information Technologies
ITC	Federal Investment Tax Credit
IVVC	Integrated Volt-Var Control
JDA	Joint Dispatch Agreement
kW	Kilowatt
kWh	Kilowatt-hour
LCOE	Levelized Cost of Energy
LCR Table	Load, Capacity, and Reserves Table
LED	Light Emitting Diodes
LEED	Leadership in Energy and Environmental Design
LEO	Legally Enforceable Obligation
LFE	Load Forecast Error
Li-ION	Lithium Ion
LNG	Liquified Natural Gas
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
M&V	Measurement and Verification
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standard
MGD	Million Gallons Per Day
MISO	Midcontinent Independent Operator

GLOSSARY OF TERMS (CONT.)

MPS	Market Potential Study
MMBtu	Million British Thermal Units
MW	Megawatt
MW AC	Megawatt-Alternating Current
MW DC	Megawatt-Direct Current
MWh	Megawatt-hour
MWh AC	Megawatt-hour-Alternating Current
MWh DC	Megawatt-hour-Direct Current
MyHER	My Home Energy Report
NAAQS	National Ambient Air Quality Standards
NAPP	Northern Appalachian Coal
NC	North Carolina
NC HB 589	North Carolina House Bill 589
NC REPS or REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
NCCSA	North Carolina Clean Smokestacks Act
NCDAQ	North Carolina Division of Air Quality
NCDEQ	North Carolina Division of Environmental Quality
NCEMC	North Carolina Electric Membership Corporation
NCMPA1	North Carolina Municipal Power Agency #1
NC REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
NCTPC	NC Transmission Planning Collaborative
NCUC	North Carolina Utilities Commission
NEM	Net Energy Metering
NEMS	National Energy Modeling Systems
NERC	North American Electric Reliability Corporation
NERC RAPA	Reliability and Performance Analysis
NES	Neighborhood Energy Saver
NESHAP	National Emission Standards for Hazardous Air Pollutants
NET CONE	Net Cost of New Entry
NGCC	Natural Gas Combined Cycle
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System

GLOSSARY OF TERMS (CONT.)

NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standard
NUG	Non-Utility Generator
NUREG	Nuclear Regulatory Commission Regulation
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
O&M	Operating and Maintenance
OATT	Open Access Transmission Tariff
PC	Participant Cost Test
PD	Power Delivery
PERFORM	Performance-based Energy Resource Feedback, Optimization and Risk Management
PEV	Plug-In Electric Vehicles
PHS	Pumped Hydro Storage
PJM	PJM Interconnection, LLC
PMPA	Piedmont Municipal Power Agency
PPA	Purchase Power Agreement
PPB	Parts Per Billion
PRB	Powder River Basin
PROSYM	Production Cost Model
PSCSC	Public Service Commission of South Carolina
PSD	Prevention of Significant Deterioration
PSH	Pumped Storage Hydro
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
PVDG	Solar Photovoltaic Distributed Generation Program
PVRR	Present Value Revenue Requirement
QF	Qualifying Facility
RCRA	Resource Conservation Recovery Act
REC	Renewable Energy Certificate
REPS or NC REPS	Renewable Energy and Energy Efficiency Portfolio Standard

GLOSSARY OF TERMS (CONT.)

RFP	Request for Proposal
RICE	Reciprocating Internal Combustion Engines
RIM	Rate Impact Measure
RPS	Renewable Portfolio Standard
RRP	Refrigerator Replacement Program
RTO	Regional Transmission Organization
RTR	Residential Risk and Technology Review
SAE	Statistical Adjusted End-Use Model
SAT Solar	Single-Axis Tracking Solar
SB 3 or NC SB 3	North Carolina Senate Bill 3
SC	South Carolina
SC Act 62	South Carolina Energy Freedom Act of 2018
SC DER or SC ACT 236	South Carolina Distributed Energy Resource Program
SC DER	South Carolina Distributed Energy Resources
SCR	Selective Catalytic Reduction
SEER	Seasonal Energy Efficiency Ratio
SEIA	Solar Energy Industries Association
SEPA (Ch. 15)	Smart Electric Power Alliance
SEPA (Ch. 2)	Southeastern Power Administration
SERC	SERC Reliability Corporation
SERVM	Strategic Energy Risk Valuation Model
SG	Standby Generation or Standby Generator Control
SIP	State Implementation Plan
SISC	Solar Integration Services Charge
SLR	Subsequent License Renewal
SMR	Small Modular Reactor
SO	System Optimizer
SO2	Sulfur Dioxide
SOC	State of Charge
SOG	Self-Optimizing Grid
SPM	Sequential Peaker Method

GLOSSARY OF TERMS (CONT.)

SRP – SLR	Standard Review Plan for the Review of Subsequent License Renewal
STAP	Short-Term Action Plan
STEO	Short-Term Energy Outlook
SVC	Static Var Compressors
T&D	Transmission & Distribution
TAG	Technology Assessment Guide
TCFD	Trillion Cubic Feet per Day
Transco	Transcontinental Pipeline
The Company	Duke Energy Progress
The Plan	Duke Energy Progress Annual Plan
TRC	Total Resource Cost
TVA	Tennessee Valley Authority
UCT	Utility Cost Test
UEE	Utility Energy Efficiency
UNC	University of North Carolina
USCPC	Ultra-Supercritical Pulverized Coal
VACAR	Virginia/Carolinas
VAR	Volt Ampere Reactive
VCEA	Virginia Clean Economy Act
VVO	Volt-Var Optimization
WCMP	Western Carolinas Modernization Project (DEP)
WERP	Weatherization and Equipment Replacement Program
WIIN	Water Infrastructure Improvement for the Nation Act
ZELFR	Zero – Emitting Load Following Resource

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