DUKE ENERGY

DUKE ENERGY PROGRESS SOUTH CAROLINA INTEGRATED RESOURCE PLAN UPDATE

2022

CONTENTS

CONTENTS

INTRODUCTION AND OVERVIEW

Introduction

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 its customers at rates below the national average. Duke Energy Progress ("DEP"), a public utility subsidiary of Duke Energy, utilizes a diverse resource mix, comprised of coal, natural gas, nuclear, solar, and hydroelectric generation, to serve over 1.6 million customers in a 29,000 square-mile service area of North Carolina and South Carolina. In planning for the future, Duke Energy is transforming the way it does business by investing in increasingly cleaner resources, modernizing the grid and transforming the customer experience.

The South Carolina Energy Freedom Act of 2019 ("Act 62") requires DEP to submit comprehensive Integrated Resource Plans ("IRP") for review by the Public Service Commission of South Carolina ("PSCSC" or the "Commission") at least every three years. DEP filed its most recent comprehensive IRP with the Commission on September 1, 2020, setting forth six resource portfolios that included various assumptions on future potential resource mixes. On June 28, 2021, the Commission issued Order No. 2021-447, requiring certain modifications to the September 2020 IRP. In response to this order, on August 27, 2021, DEP subsequently filed its Supplemental Portfolios & Analysis, providing an additional nine resource portfolios, which, together with the September 2020 IRP, constituted DEP's SC Modified IRP. DEP selected Portfolio C1 ("Earliest Practicable Coal Retirements") as its "Preferred Plan." In Order No. 2022-332, the PSCSC rejected Portfolio C1 as DEP's preferred resource plan and directed that DEP use Portfolio A2 as the selected base plan for its Modified 2020 IRP.

Pursuant to Act 62, this document serves as the annual update to DEP's SC Modified 2020 IRP, reflecting required updates to base planning assumptions for Portfolio A2 for compliance purposes. DEP plans to file its next comprehensive IRP with the Commission in 2023.

2022 SC IRP Update Overview

Act 62 requires that DEP submit annual updates to its most recently accepted resource plan, including updates to certain base planning assumptions, and requires that the update "describe the impact of the updated base planning assumptions on the selected resource plan."[1] Accordingly, in compliance with Act 62 and Order Nos. 2021-509 and 2022-332, the Company is providing this update to its base planning assumptions relative to its resource plan, which has been selected by the Commission as Portfolio A2.

This 2022 SC IRP Update ("SC IRP Update" or "IRP Update") illustrates how updates to base planning assumptions impact the selected resource plan. For example, the IRP Update includes updates to the Company's load forecast, energy efficiency projections, the capacity value of renewable resources and batteries (through the updated Effective Load Carrying Capability Study), and updated cost projections and operational assumptions for all supply-side resources evaluated in the plan update. However, evolving economics, regulatory requirements, federal and state policies, and technological advancements underlying key resource planning assumptions will drive significant changes to the upcoming comprehensive IRP. Further, applicable Commission orders require additional resource planning analysis that will also influence the IRP modeling and results that will be presented in 2023. For these reasons, the IRP Update does not result in a resource plan that is fully suitable for execution, as the Company's comprehensive integrated resource plan is expected to change significantly in 2023.

For example, pursuant to the Commission's Order, the price for 20-year solar power purchase agreements ("PPA") in this IRP Update remains at $38/MWh, a price that is based on historic market intelligence that is over three years old as of the time of this IRP Update. As discussed in Chapter 5 – Renewable Energy and Energy Storage Resources, in the 2023 comprehensive IRP, the Company expects to have updated market intelligence to develop a solar PPA price that will be more reflective of current market conditions. In a similar fashion, as directed by the Commission, this update assumes battery storage costs based on the National Renewable Energy Laboratory's ("NREL") most aggressive price decline forecast for utility-scale battery storage technology. For the 2023 comprehensive IRP, the Company will seek to incorporate updated market data as it becomes available in order to better align planning assumptions with current market realities for battery storage.

Moreover, ongoing regulatory proceedings for resource planning in North Carolina will conclude in December of this year. Given the integrated dual-state systems operated by DEC and DEP in the Carolinas, the outcome of that proceeding will be foundational to the next comprehensive IRP to be filed in South Carolina in 2023. This Commission also set forth a number of updates and new requirements that must also be incorporated into the next comprehensive IRP pursuant to Order No. 2021-447, which are not a part of this 2022 IRP Update. All of these elements will be addressed in DEP's next comprehensive IRP in 2023 and will result in a significantly different resource plan.

---

[1] S.C. Code Ann. § 58-37-40(D)(1). Recognizing that DEC's 2020 Modified IRP was only recently approved by Order No. 2022-332 in May 2022, the Company is submitting this IRP Update in compliance with S.C. Code Ann. § 58-37-40(D)(1) to meet the statutory requirements for 2021 and 2022.

In sum, DEP's 2022 SC IRP Update complies with the requirements of Act 62 and the requirements of applicable Commission orders. Given the factors described above, the results of the SC IRP Update serve to illustrate the impact of updating base planning assumptions, but do not create an executable, long-term resource plan. The Company looks forward to presenting a comprehensive IRP to the Commission in 2023, addressing all of these factors.

2022 SC IRP Update Modeling Results

Table 1-A and Figure 1-A below provide a summary of the 2022 SC IRP modeling results.

Table 1-A: Portfolio A2 Update Results – DEP and DEP/DEC Combined System

	Duke Energy Carolinas	DEP/DEC Combined System
System CO_2 Reduction by 2037[1]	52%	52%
Present Value of Revenue Requirements (PVRR, $B)	$27.1	$75.4
Total System Solar (MW) by Beginning of 2037[2,3]	5,945	10,544
Incremental Onshore Wind (MW) by Beginning of 2037	0	0
Incremental Offshore Wind (MW) by Beginning of 2037	0	0
Incremental SMR (MW) by Beginning of 2037	0	0
Incremental Storage (MW) by Beginning of 2037[2,4]	1,473	3,192
Incremental Gas (MW) by Beginning of 2037	3,063	4,740
Total Contribution from Energy Efficiency and Demand Response Initiatives (MW) by Beginning of 2037[5]	1,461	3,432
Remaining Dual Fuel Coal Capacity by Year-End 2037 (MW)	0	3,069

[1]Combined DEP/DEC system CO_2 reductions from 2005 baseline

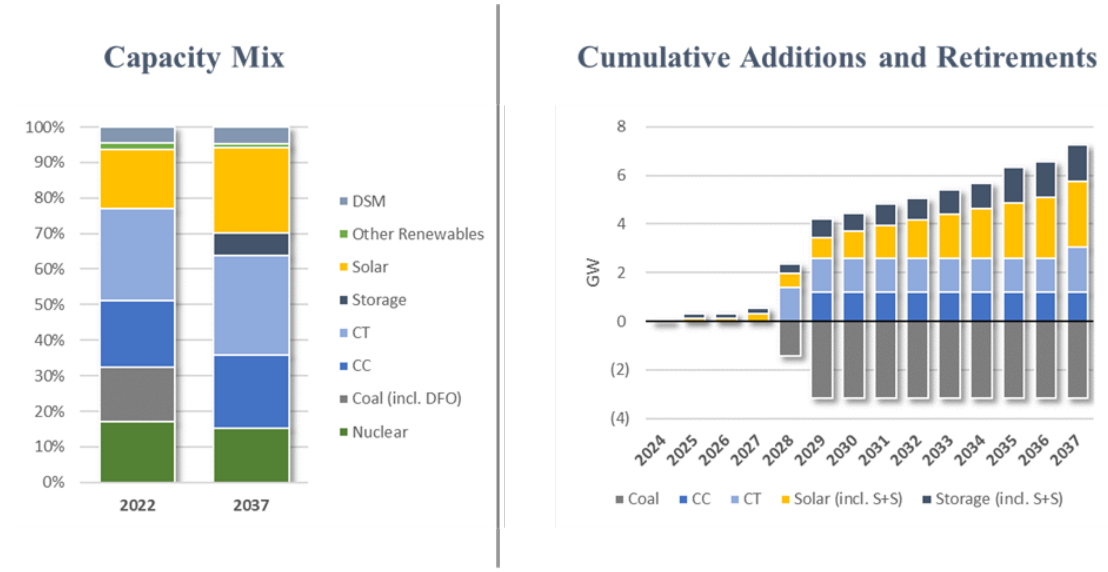
[2]Nameplate

[3]Includes solar-plus-storage resources

[4]Includes batteries paired with solar

[5]Contribution in peak winter planning hour

Figure 1-A: DEP Portfolio A2 Update – Winter (Nameplate for Renewables and Storage)



The specific modeling assumptions and explanation of modeling process, as well as results are included in subsequent chapters.

UPDATES TO BASE PLANNING ASSUMPTIONS

In the development of an IRP Update, modeling data is updated to reflect the most current data available to Duke Energy Progress ("DEP" or the "Company"). Act 62 describes the IRP update requirements as follows:

> *an electrical utility and the Public Service Authority shall each submit annual updates to its integrated resource plan to the commission. An annual update must include an update to the electric utility's or the Public Service Authority's base planning assumptions relative to its most recently accepted integrated resource plan, including, but not limited to: energy and demand forecast, commodity fuel price inputs, renewable energy forecast, energy efficiency and demand-side management forecasts, changes to projected retirement dates of existing units, along with other inputs the commission deems to be for the public interest.*

This chapter provides an overview of updates made to the base planning assumptions for several of the major inputs, relative to assumptions used to develop Portfolio A2 in the 2020 SC Modified IRP. The updated Portfolio A2 discussed in this document reflects these changes.

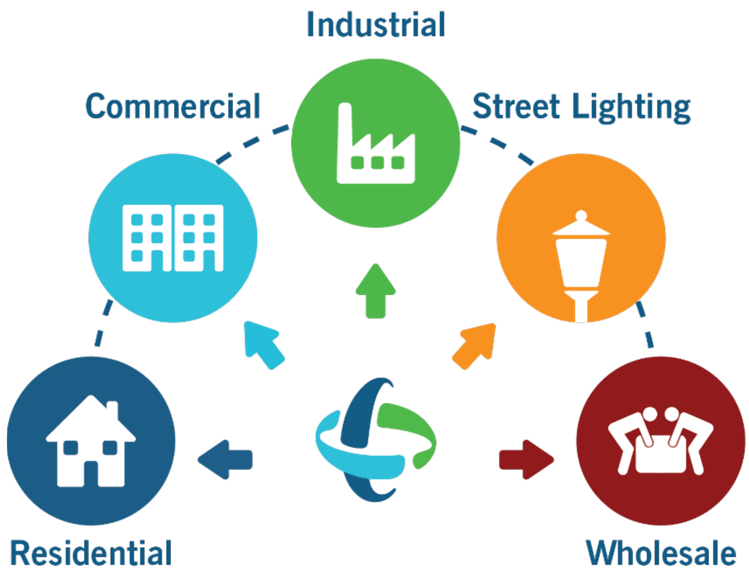
Use of EnCompass Model

In 2022, the Company moved to the EnCompass suite of resource planning models from Anchor Power Solutions to address the enhanced planning needs of the Company. As described in the 2020 IRP proceeding, the plans to shift to the new EnCompass model were based, in part, on feedback from stakeholders as part of the 2020 IRP development process. The transition to the EnCompass models is complete and has been utilized in the development of Portfolio A2 in the 2022 SC IRP Update.

Load Forecast

The DEP Fall 2021 load forecast used in this IRP Update includes projections of the energy and peak demand needs for the Company's service area. The forecast covers the time period of 2023 – 2037 and represents the needs of the following customer classes:

DEP 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 Fall 2021 forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of South Carolina and North Carolina. Moody's forecasts consist of economic and demographic projections, which are used in the energy and demand models.

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.

Each time the load forecast is updated, the most currently available historical and projected data is used. The Fall 2021 forecast used in this IRP update is based on:

- Moody's Analytics July 2021 base and consensus economic projections.
- End use equipment and appliance indexes reflect the 2021 update of Itron's end-use data, which is consistent with the EIA's 2021 Annual Energy Outlook.
- A calculation of normal weather using the period 1991-2020.

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. Historical peaks and forecasted peaks are provided in Chapter 3 – Electric Load Forecast.

Table 2-A below depicts the projected average annual growth rates of several key drivers for DEP's Fall 2021 forecast, with comparison to drivers for the Spring 2020 forecast used in the Modified 2020 IRP.

Table 2-A: Fall 2021 vs. Spring 2020 Annualized Growth Rates of Key Economic Drivers

	Fall 2021 Forecast (2023 – 2037)	Spring 2020 Forecast (2021 – 2035)
Real Income	0.6%	2.9%
Manufacturing Industrial Production Index ("IPI")	1.3%	1.1%
Population	1.6%	1.5%

In addition to economic, demographic, and efficiency trends, the forecast also incorporates the expected impacts of utility energy efficiency ("UEE" or "EE")[1], as well as projected effects of electric vehicles ("EV") and behind the meter solar technology ("PV").

Table 2-B below provides a comparison of the average annual growth rates of forecasted energy sales by customer class, including the impacts of UEE, EV, and PV for the Fall 2021 load forecast used in this IRP Update and the Spring 2020 load forecast used in the 2020 Modified IRP.

Table 2-B: Fall 2021 vs. Spring 2020 Average Annual Growth Rates of Forecasted Energy Sales by Customer Class

	Fall 2021 Forecast (2023 – 2037)	Spring 2020 Forecast (2021 – 2035)
Residential	0.7%	1.4%
Commercial	0.6%	0.2%

[1] UEE specifically refers to the approved programs offered by the Company where participants actively take part in conservation and demand response measures offered under the EE/DSM riders within the service territory. For purposes of this document, UEE and EE terms may be used interchangeably to refer to approved utility programs unless otherwise noted.

	Fall 2021 Forecast (2023 – 2037)	Spring 2020 Forecast (2021 – 2035)
Industrial	0.1%	-0.2%
Other	-1.0%	-0.3%
Total Retail	0.5%	0.6%

Note: Includes impacts of UEE, rooftop solar and electric vehicles.

Additionally, Table 2-C below represents a comparison of the average annual growth rates of forecasted winter and summer peak demands, as well as energy demands for the Fall 2021 and Spring 2020 load forecasts.

Table 2-C: Fall 2021 Load Forecast Growth Rates vs. Spring 2020 Load Forecast Growth Rates (Inclusive of Retail and Wholesale Load)

	Fall 2021 Forecast (2023 – 2037)			Spring 2020 Forecast (2019 – 2033)		
	Summer Peak Demand	Winter Peak Demand	Energy	Summer Peak Demand	Winter Peak Demand	Energy
Excludes impact of new EE programs	0.9%	0.7%	0.8%	1.0%	1.0%	0.9%
Includes impact of new EE programs	0.8%	0.6%	0.7%	0.9%	0.9%	0.8%

Additional detail on the Fall 2021 load forecast is provided in Chapter 3 – Electric Load Forecast.

Energy Efficiency, Demand Response, and IVVC

Per PSCSC Order No. 2021-447, "Duke is required to use the Utility Cost Test (UCT) when developing EE/DSM scenarios and savings projections in its future IRPs, IRP updates, and market potential studies." DEP and DEC worked with Nexant to update the information in the 2020 Market Potential Study to use UCT to calculate achievable energy efficiency savings for use in the 2022 SC IRP Update. Table 2-D below shows the growth in impacts of Base EE programs over the fifteen-year time horizon which achieves a Compound Annual Growth Rate of 13.0% and an overall growth rate of approximately 522%.

Table 2-D: Annual MWh Load Reduction from Base EE Programs

YEAR	ANNUAL MWH LOAD REDUCTION (NET OF FREE RIDERS) Including Measures Added in 2022 and Beyond
2022	396,784
2037	2,469,626

For demand response, the Companies have incorporated results of the winter peak study discussed in the 2020 IRP in the demand response ("DR") projections utilized in this 2022 SC IRP Update. Table 2-E below shows the growth in impacts of DR programs over time at winter peak, achieving a Compound Annual Growth Rate of 6.1% and an overall growth rate of 144.7% over the fifteen-year time horizon.

Table 2-E: Growth Impact of Winter DR Programs

YEAR	WINTER PEAK MW REDUCTION					
	ENERGYWISE HOME	CIG DEMAND RESPONSE	LARGE LOAD CURTAILABLE	ENERGYWISE FOR BUSINESS	ADR	TOTAL WINTER PEAK
2022	5	18	224	1	0	248
2037	310	25	235	9	29	606

Note: Data excludes the impact of wholesale DR programs.

In the 2020 IRP, DEP included the impacts of the existing Distributed System Demand Response (DSDR) program which will roll into the Integrated Volt-Var Control (IVVC) program. The Company does not expect that changing the predominant operational strategy in DEP from DSDR to CVR mode will reduce peak shaving capability available today under DSDR.

Please see Chapter 4 – Energy Efficiency, Demand-Side Management and Voltage Optimization, for a detailed account of the impacts of EE/DSM and IVVC on the DEP system.

Renewable Energy

The 2022 SC IRP Update includes several updates to operational assumptions for solar resources that are available to be selected by the model. Future solar resources are assumed to have bifacial panels and it is assumed that 60% of future solar would be located in the DEP service territory with the remaining 40% assumed to be located in DEC. Consistent with PSCSC Order No. 2021-447 and Portfolio A2 of the 2020 Modified IRP, the Companies applied a 750 MW annual solar interconnection constraint. Consistent with the Commission's previous orders, the Companies also included third-party solar PPAs with a price of $38/MWh as a selectable resource, with the base case allowing up to 50% of the solar available to be selected as the $38/MWh PPA option, and with the alternative case allowing 100% of the solar to be selected at this option.

As in the 2020 SC Modified IRP, onshore wind is included as a selectable resource in DEP, which is available in the model as high-capacity factor wind along the Carolinas coast. Also, as in the 2020 SC Modified IRP, DEP includes offshore wind as a selectable resource in the 2022 SC IRP Update.

Chapter 5 – Renewable Energy and Energy Storage Resources includes additional detail on the renewable energy assumptions used in this 2022 SC IRP update.

Energy Storage

Energy storage will serve in the future to support additional deployment of intermittent solar resources and act as an important dispatchable resource supporting future coal plant retirements.

The Company continues to include 4-hour and 6-hour battery energy storage as model-selectable resources in the IRP analysis, and has added an 8-hour option for this IRP update. For the 2022 SC IRP Update, DEP added a 2-hour battery paired with solar option to be selected along with the 4-hour battery paired with solar option that was available in the 2020 Modified IRP.

As directed by the Commission, the Company's selectable battery storage resource prices are consistent with the "Advanced Costs" assumption from the 2021 NREL Annual Technology Baseline ("ATB") report.

Chapter 5 – Renewable Energy and Energy Storage Resources includes additional detail on the energy storage assumptions used in this IRP update.

Effective Load Carrying Capability ("ELCC") Study

Consistent with Order No. 2021-447, the Companies have made several adjustments to the solar and storage ELCCs. The specific changes required by the Commission are discussed in more detail in Chapter 6 – Development of the Resource Plan. This 2022 SC IRP Update incorporates these changes as directed by the Commission.

DEP and DEC worked with Astrapé Consulting to conduct a new ELCC study to understand the reliable capacity contributions of solar, onshore wind, offshore wind, and storage for use in the planning process. Importantly, these ELCC results reflect the "synergistic benefits" of other variable resources present on the system. The solar and storage ELCC values used in EnCompass reflect the synergistic effect that these resources have on each other's capacity values as their deployment increases on the system. The Companies applied discrete ELCC values for solar, storage, and wind resources that capture this synergistic value.

Additional detail on the ELCC Study and ELCC values used in the 2022 SC IRP Update can be found in Chapter 6 – Development of the Resource Plan as well as the ELCC Study Report provided as Attachment I.

Retirement Dates of Existing Resources

The 2020 IRP included a detailed coal plant retirement analysis to determine the most economic retirement dates for each of the Company's coal assets. These coal retirement dates were reflected in Portfolio A2 in the 2020 IRP and 2020 SC Modified IRP. The Company continues to rely on these retirement dates for the purposes of the 2022 SC IRP Update. These retirement dates are provided in Table 2-F below.

TABLE 2-F: Coal Retirement Dates in the Approved 2020 Resource Plan

Coal Plant	Retirement Year (Jan 1)
Roxboro 3 & 4	2028
Roxboro 1 & 2	2029
Mayo 1	2029

Since the filing of the 2020 IRP, the Company has further reviewed the retirement dates for the existing natural gas combustion turbine units on the DEP system. Based on this review, the Company determined that the retirement dates for several existing CT units must be extended to ensure reliability to the DEP system as coal units are retired and additional variable energy resources are added. The changes in these retirement dates are presented in Table 2-G below.

TABLE 2-G: UPDATES TO EXISTING CT RETIREMENT DATES

Plant	2022 SC IRP Update Retirement Dates (Jan)	2020 IRP/2020 Modified IRP Retirement Dates (Jan)
Blewett	2040	2026
Weatherspoon	2040	2026

Fuel Costs

As directed by the PSCSC, the natural gas price forecast used in the development of Portfolio A2 in the 2020 SC Modified IRP consisted of eighteen months of market pricing, followed by an eighteen-month transition from market to fundamentals-based pricing, and then relies on fundamentals-based pricing for the remainder of the planning period. This IRP update uses the same forecast blend schedule for both gas and coal prices. In addition, to reduce forecast volatility and limit reliance on any one set of forecast assumptions, the fundamentals-based fuel price forecast used in the 2022 SC IRP Update is an average of fundamentals-based forecasts from four providers. Additional detail is provided in Chapter 9 – Fuel Commodity Prices.

Selectable Resource Technologies

The capital, operating, and associated transmission costs of selectable resources represent the Company's most current estimates at the time the dataset is locked for modeling purposes. Similar to the 2020 IRP, the Company considered a diverse range of technology choices utilizing a variety of different fuels in order to meet future generation needs in the 2022 SC IRP Update. Technologies available for selection in the 2022 SC IRP Update capacity expansion process are listed below.

Technologies (Winter Ratings):

- Base load – 1,216 MW 2x2x1 Advanced Combined Cycle (No Inlet Chiller and Fired)
- Base Load – 285 MW Small Modular Reactor (SMR)
- Base Load – 345 MW Advanced Nuclear Reactor (AR) with Thermal Storage
- Peaking/Intermediate – 924 MW 4 x 7FA.05 Combustion Turbines (CTs)
- Storage – 60 MW / 240 MWh Li-Ion Battery (4-hour)
- Storage – 60 MW / 360 MWh Li-Ion Battery (6-hour)
- Storage – 50 MW / 400 MWh Li-Ion Battery (8-hour)
- Intermittent – 75 MW Solar PV, Bifacial and Single Axis Tracking (SAT)
- Intermittent – 75 MW Solar PV plus 20 MW / 80 MWh or 40 MW / 80 MWh Li-ion Battery
- Intermittent – 150 MW Onshore Wind
- Intermittent – 1600 MW Offshore Wind

Additional detail regarding technology changes included in the 2022 SC IRP Update may be found in Chapter 6 – Development of the Resource Plan.

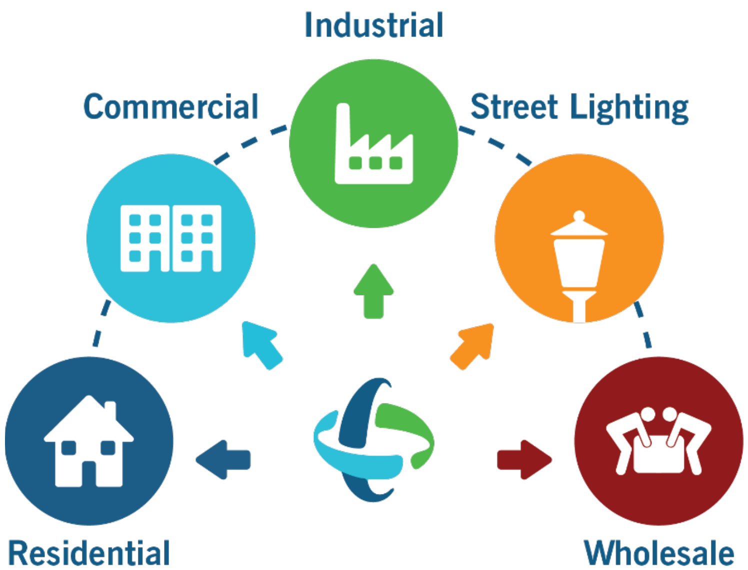
ELECTRIC LOAD FORECAST

Pursuant to Act 62, Duke Energy Progress' ("DEP's" or the "Company") 2022 SC IRP Update includes an update to the Company's electric load forecast. The DEP Fall 2021 Forecast provides projections of the energy and peak demand needs for its service area and is an update from the DEP Spring 2020 Forecast, which was used in the 2020 DEP Integrated Resource Plan.

Customer Classes

The forecast covers the time period of 2023 to 2037 and represents the needs of the following customer classes shown in Figure 3-A below:

Figure 3-A: DEP Load Forecast Customer Classes



DEP developed its energy projections 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. The residential customer model also uses population factors.

The DEP Fall 2021 forecast reflects economic projections obtained from Moody's Analytics, a nationally recognized economic forecasting firm, including economic forecasts for the states of South Carolina and North Carolina. Moody's forecasts consist of economic and demographic projections, which are used in the energy and demand models.

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 projection is the number of residential customers, which is driven by population. The second projection is energy usage per customer, which is driven by weather, regional economic and demographic trends, electricity prices and appliance efficiencies.

DEP derived the usage per customer forecast 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 DEP Fall 2021 Forecast, including the impacts of Utility Energy Efficiency programs ("UEE"), rooftop solar and electric vehicles from 2023 to 2037 is 0.7%.

DEP also uses an SAE model to develop the commercial forecast and reflect naturally occurring as well as government mandated efficiency changes. The three largest sectors in the commercial class are offices, education and retail. Commercial energy sales are expected to grow 0.6% per year over the forecast horizon.

DEP derived its Industrial class forecast using a standard econometric model, with drivers such as total manufacturing output and the price of electricity. Overall, Industrial sales are expected to grow 0.1% per year over the forecast horizon.

Weather impacts are incorporated into the models 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.

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

Finally, DEP projected Peak demands using the SAE model. 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, as well as describe 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 Company uses the most current available historical and projected data. The current forecast utilizes:

- Moody's Analytics July 2021 base and consensus economic projections.
- The 2021 update of ITRON's end-use data, which is consistent with the Energy Information Administration's 2021 Annual Energy Outlook (for end-use equipment and appliance indexes).
- A calculation of normal weather using the period 1991-2020

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. Historical peaks and forecasted peaks can be viewed later in this appendix.

Assumptions

Table 3-A below shows the projected average annual growth rates of several key drivers from DEP's Fall 2021 Forecast.

Table 3-A: Annualized Growth Rates of Key Economic Drivers

	2023-2037
Real Income	0.6%
Manufacturing Industrial Production Index (IPI)	1.3%
Population	1.6%

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

Utility Energy Efficiency

Utility Energy Efficiency Programs continue to have a large impact in accelerating 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, continuing to reduce the forecasted load resulting from energy efficiency adoption.

Table 3-B below illustrates this process on sales:

Table 3-B: 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
2023	64,622	14	64,636	(531)	154	(377)	64,259
2024	65,217	46	65,263	(777)	154	(622)	64,641
2025	65,300	102	65,402	(1,014)	154	(860)	64,542
2026	65,351	183	65,534	(1,244)	155	(1,089)	64,444
2027	65,579	279	65,858	(1,464)	156	(1,308)	64,549
2028	65,971	383	66,354	(1,663)	156	(1,507)	64,847
2029	66,395	461	66,856	(1,834)	159	(1,674)	65,182
2030	66,801	557	67,359	(1,976)	166	(1,810)	65,549
2031	67,308	618	67,926	(2,090)	190	(1,900)	66,026
2032	67,967	658	68,625	(2,176)	246	(1,931)	66,694
2033	68,552	682	69,234	(2,241)	318	(1,922)	67,312
2034	69,208	694	69,902	(2,296)	402	(1,894)	68,008
2035	69,907	700	70,607	(2,349)	502	(1,846)	68,761
2036	70,674	700	71,374	(2,399)	619	(1,780)	69,594
2037	71,397	700	72,097	(2,448)	771	(1,677)	70,420

Critical Peak Pricing

The Critical Peak Pricing (CPP) Rate Rider is a dynamic overlay option for Duke's electric service, including both its existing flat volumetric rates as well as its existing and newly proposed time-of-use (TOU) rates. This time variant pricing option allows Duke to call critical events up to 20 times per year (20 CP) based on system conditions such as when there is expected to be extreme temperatures, high energy usage, high market energy costs, or major generation or transmission outages. Customers enrolled will be alerted the day before a critical event and agree to pay a higher price for peak time electricity use during these critical events, encouraging reductions in demand. DEP included daily load and peak impacts for CPP in the peak demand projections for DEP. The critical events (20 CP) were modeled to impact the projected 10 highest winter days and 10 highest summer days in each year.

Table 3-C below shows the CPP projected peak reduction capabilities for Winter and Summer demands:

Table 3-C: CPP Peak Reduction Capabilities (MW) - DEP

Year	Summer (MW)	Winter (MW)
2023	12	8
2024	24	18
2025	38	30
2026	55	46
2027	76	65
2028	100	87
2029	126	112
2030	153	139
2031	180	167
2032	207	194
2033	231	219
2034	252	242
2035	270	261
2036	284	277
2037	296	290

Rooftop Solar

Net energy metering ("NEM") is currently available in the Carolinas. The forecast used in the Plan reflects impacts from approved NEM rates in the Carolinas as of January 1, 2022, which are decremented directly from the initial Itron model output. Table 3-D below summarizes the number of current customers enrolled in net metering rate programs for both the DEP and DEC service areas by customer class, as well as the total energy in megawatt-hours ("MWh") forecasted to be generated from behind-the-meter ("BTM") solar generation on customer sites in 2022.

Table 3-D: Number of Customers Enrolled in Net Metering Rate Programs and Forecasted BTM Generation

	2022 Enrollment (as of 1/1/2022)		2022 BTM Generation Forecast	
System	**Residential**	**Non-Residential**	**Residential**	**Non-Residential**
DEP	14,017	477	138,325 MWh	44,755 MWh

Modeling NEM Adoption

Residential rooftop solar systems are limited in size pursuant to state law in both South Carolina and North Carolina, which requires a facility to be less than 20 kilowatts-alternating current ("kW-AC"), also referred to as nameplate capacity for solar facilities. Non-residential customers' solar systems may not exceed the lesser of 1,000 kW-AC or 100% of the customer's contract demand, which approximates the customer's maximum expected demand. Table 3-E below shows the average size of rooftop solar facilities in the Carolinas.

Table 3-E: Average Rooftop Solar Capacity (KW-AC)

Customer Class	DEP-NC	DEP-SC
Residential	6.5	7.9
Non-residential	63	86

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. The adoption forecasts are developed using economic models of payback, which is a function of installed cost, regulatory incentives, regulatory statutes and bill savings. A relationship between payback and customer adoption is developed through regression modeling, with the resulting regression equations used to predict future customer adoptions based on projected payback curves.

Historical and projected technology costs are sourced from Guidehouse, while projected incentives and bill savings are based on current regulatory policies as well as input from internal subject matter experts. Average system size (capacity) values are based on trends in historical adoption.

The hourly production profiles have 12x24 resolution, which equates to one 24-hour profile for each month. Profiles are derived from actual production data, where available, and solar photovoltaic ("PV") modeling. The PV modeling is performed in the PVsyst model using 20+ years of historical irradiance data sourced from Solar Anywhere and Solcast. Models are created for 13 irradiance locations across DEC's service area and nine irradiance locations across DEP's service area with 21 tilt/azimuth configurations. The results for each jurisdiction are combined on a weighted average basis to produce the final profiles.

Table 3-F below shows the Companies' growth projection for new solar customers and new energy benefits from 2022 through 2037under the currently approved net metering rate designs in the Carolinas as of January 1, 2022.

Table 3-F: 2037 Rooftop Solar, Net New from 2022 through 2037

	DEP	
	Residential	Non-Residential
Number of Customers	38,522	1,415
Energy (MWh)	352,064	111,300

Electric Vehicles

Major automakers, including Ford, GM and Stellantis (which is comprised of 16 auto brands, including Chrysler, Dodge, and Jeep), have announced a goal to achieve 40%-50% of new vehicle sales be electric by 2030. Also, in August 2021, the Biden Administration announced a goal of 50% of new U.S. passenger car and light truck sales being electric by 2030[1].1. New vehicle sales are only a portion of the vehicles in operation, but the load growth associated with charging electric vehicles ("EV") is expected to accelerate over the planning horizon.

Duke Energy's EV load forecast is derived using the Vehicle Analytics and Simulation Tool ("VAST"). A series of EV forecasts and load charging profiles are generated in VAST to produce an hourly load forecast broken down by three duties: light, medium and heavy. All three duties are calculated using similar methodology and make up the EV load forecast that is added to the DEP load forecast.

Multiple parameters are accounted for when developing the EV adoption forecast including historical data, such as vehicle registrations, vehicle utilization characteristics, projections of cost, vehicle availability, charging infrastructure availability and consumer acceptance.

Based on the adoption forecast and the projected amount of energy needed to charge the EVs, hourly EV demand profiles are developed in VAST using third-party charging characteristic data for the different types of vehicles and chargers. The VAST tool then combines the EV vehicle forecast and the hourly load profiles to develop jurisdictional hourly level load profiles that are used in the DEP load forecast.

Table 3-G below shows the projected incremental additions of EVs in operation, along with the impacts on energy, near the beginning and ending of the planning horizon.

[1] FACT SHEET: President Biden Announces Steps to Drive American Leadership Forward on Clean Cars and Trucks | The White House. (Aug. 5, 2021), *available at* https://www.whitehouse.gov/briefing-room/statements-releases/2021/08/05/fact-sheet-president-biden-announces-steps-to-drive-american-leadership-forward-on-clean-cars-and-trucks/.

Table 3-G: Electric Vehicles, EVs in Operation and Load Impacts – DEP

Year	EVs In Operation	Percent Of Vehicle Fleet	Load (MWh/Year)
2022	24,667	.74%	17,700
2037	311,976	7.70%	2,300,000

Net Impact of Rooftop Solar and Electric Vehicles

Figures 3-B through 3-D 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. The load forecast is incremented by these projections.

Figure 3-B: Percent Impact of PV and EV on Annual Load in DEP, Net New from 2022

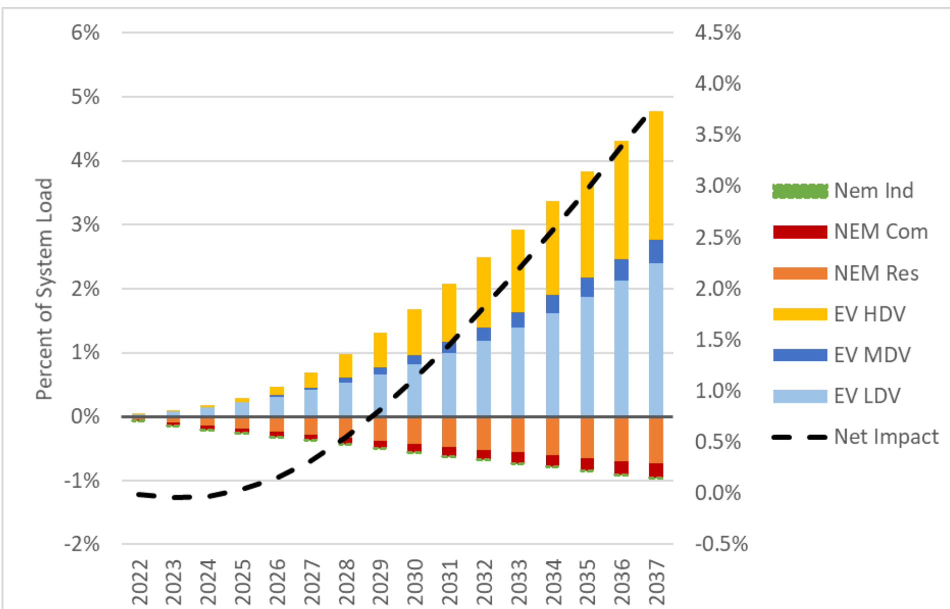


Figure 3-C: Percent Impact of PV and EV on Winter Peak Load in DEP, Net New from 2022

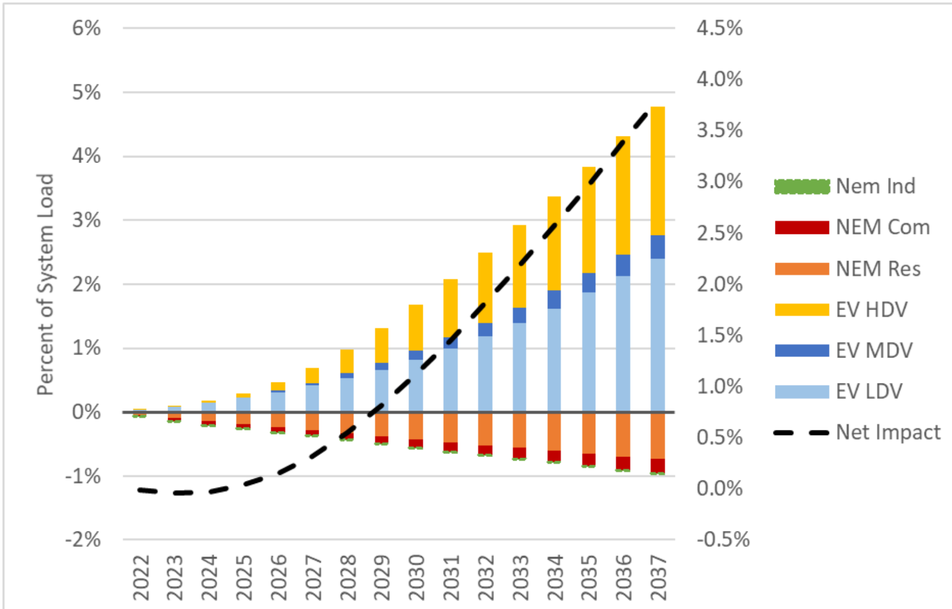
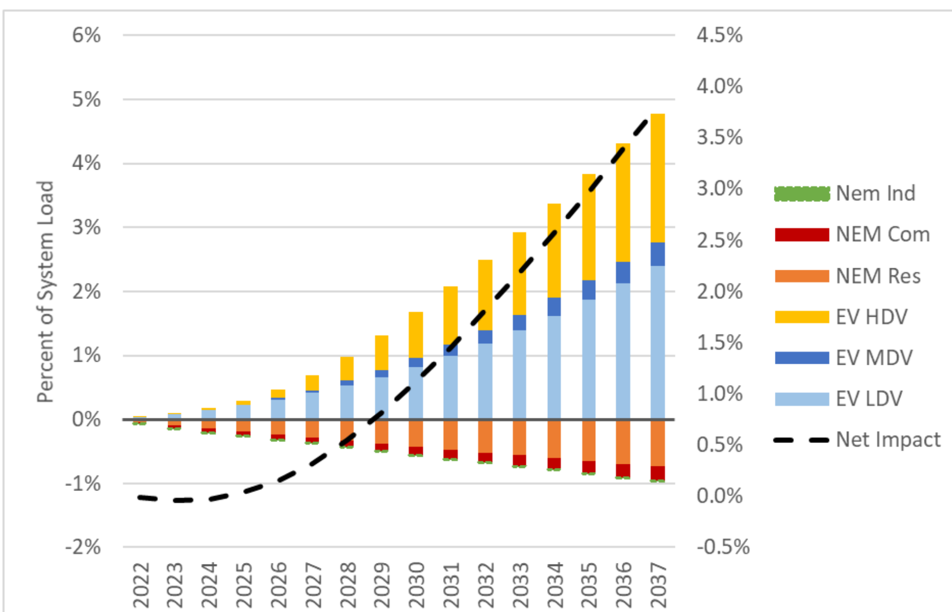


Figure 3-D: Percent Impact of PV and EV on Summer Peak Load in DEP, Net New from 2022



Customer Growth

Tables 3-H and 3-I show the history and projections for DEP customers.

Table 3-H: Retail Customers (Annual Average In Thousands)

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2012	1,231	219	4	2	1,457
2013	1,242	222	4	2	1,470
2014	1,257	223	4	2	1,486
2015	1,275	226	4	2	1,507
2016	1,292	229	4	2	1,527
2017	1,310	232	4	1	1,547
2018	1,331	235	4	1	1,571
2019	1,349	237	4	1	1,591
2020	1,375	239	4	1	1,620
2021	1,397	242	4	2	1,644
Avg. Annual Growth Rate	1.4%	1.1%	-1.8%	-0.9%	1.4%

Table 3-I: Retail Customers (Thousands, Annual Average)

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2023	1,434	249	4	1	1,688
2024	1,449	251	4	1	1,706
2025	1,464	253	4	1	1,723
2026	1,478	256	4	1	1,739
2027	1,493	258	4	1	1,756
2028	1,508	260	4	1	1,774
2029	1,524	263	4	1	1,792
2030	1,540	265	4	1	1,810
2031	1,556	267	4	1	1,828
2032	1,571	270	4	1	1,847
2033	1,587	272	4	1	1,865
2034	1,603	275	4	1	1,883
2035	1,618	277	4	1	1,900
2036	1,633	279	4	1	1,917
2037	1,647	282	4	1	1,934
Avg. Annual Growth Rate	1.0%	0.9%	-0.2%	0.4%	1.0%

Electricity Sales

Table 3-J shows the actual historical gigawatt hour (GWh) sales. As a note, the values in Table 3-J are not weather adjusted Sales.

Table 3-J: Electricity Sales (GWh)

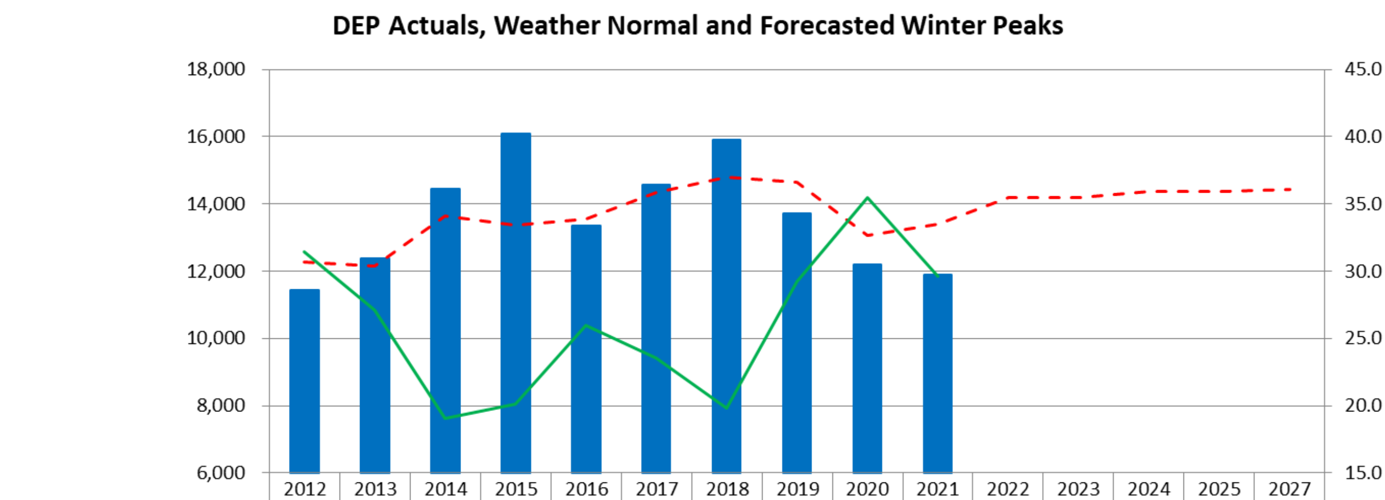
Year	Residential GWh	Commercial GWh	Industrial GWh	Military & Other GWh	Retail GWh	Wholesale GWh	Total System GWh
2012	17,764	13,709	10,573	1,591	43,637	12,267	55,903
2013	16,663	13,581	10,508	1,602	42,355	12,676	55,031
2014	18,201	13,887	10,321	1,614	44,023	13,578	57,601
2015	17,954	14,039	10,288	1,597	43,876	15,782	59,658
2016	17,686	14,082	10,274	1,563	43,606	18,676	62,282
2017	17,228	13,903	10,391	1,531	43,053	18,242	61,295
2018	18,939	14,219	10,475	1,560	45,194	19,331	64,525
2019	18,177	13,992	10,534	1,537	44,241	18,694	62,935
2020	17,587	12,894	10,122	1,495	42,099	17,216	59,315
2021	18,645	12,941	9,343	1,389	42,318	17,821	60,139
Avg. Annual Growth Rate	0.5%	-0.6%	-1.4%	-1.5%	-0.3%	4.2%	0.8%

Note: The wholesale values in Table 3-J exclude NCEMPA sales for all years before 2015 and is only partially included in 2015.

System Peaks

Figures 3-E and 3-F show the historical actual and weather normalized peaks for the system:

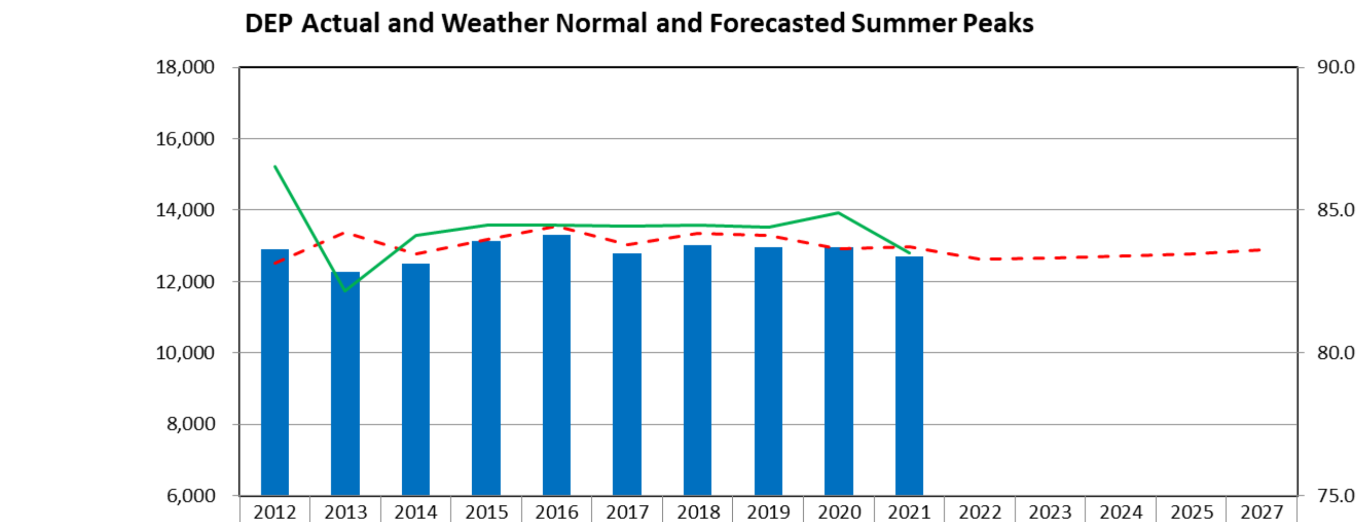
Figure 3-E: DEP Actual and Weather Normal Winter Peaks



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2027
Actuals	11,440	12,376	14,453	16,080	13,357	14,583	15,897	13,715	12,196	11,894					
WN Peak/Forecast	12,261	12,161	13,635	13,377	13,556	14,356	14,797	14,640	13,079	13,413	14,202	14,205	14,386	14,386	14,429
Temp	31.5	27.1	19.1	20.1	26.0	23.5	19.8	29.2	35.5	29.6					

Note: WN Peak/Forecast values in years 2022-2027 are forecasted peak values from the 2021 Fall Forecast. The Temperatures are the average daily temperature on the day of the peak.

Figure 3-F: DEP Actual and Weather Normal Summer Peaks



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2027
Actuals	12,912	12,273	12,497	13,134	13,296	12,792	13,029	12,953	12,966	12,691					
WN Peak/Forecast	12,520	13,378	12,778	13,188	13,554	13,038	13,339	13,279	12,925	12,970	12,625	12,655	12,725	12,761	12,901
Temp	86.5	82.2	84.1	84.5	84.5	84.4	84.5	84.4	84.9	83.5					

Note: WN Peak/Forecast values in years 2022-2027 are forecasted peak values from the 2021 Fall 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 3-K: Forecasted energy sales by class (Including the impacts of UEE, rooftop solar, and electric vehicles)
- Table 3-L: Forecast energy sales – gross load to net load (walkthrough of impacts from UEE, rooftop solar, electric vehicles and voltage control program)
- Table 3-M: Summary of the load forecast without UEE programs and excluding any impacts from demand reduction programs
- Table 3-N: 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 3-G and 3-H.

The values in these tables reflect the loads that Duke Energy Progress is contractually obligated to provide and cover the period from 2023 to 2037.

Table 3-K: Forecasted Energy Sales by Class

Year	Residential GWh	Commercial GWh	Industrial GWh	Other GWh	Retail GWh
2023	18,921	14,071	10,212	1,582	44,787
2024	19,120	14,116	10,153	1,573	44,962
2025	19,010	14,033	10,086	1,562	44,691
2026	18,892	13,961	10,027	1,538	44,418
2027	18,904	13,976	9,941	1,516	44,337
2028	18,972	14,032	9,896	1,489	44,390
2029	19,056	14,123	9,885	1,473	44,537
2030	19,171	14,188	9,900	1,443	44,702
2031	19,336	14,285	9,940	1,433	44,995
2032	19,539	14,410	10,002	1,420	45,371
2033	19,752	14,543	10,075	1,405	45,776
2034	20,013	14,690	10,137	1,396	46,235
2035	20,292	14,853	10,208	1,392	46,745
2036	20,599	15,038	10,293	1,380	47,311
2037	20,893	15,230	10,398	1,373	47,895
Avg. Annual Growth Rate	0.7%	0.6%	0.1%	-1.0%	0.5%

Note: Values are at meter.

Table 3-L: Forecasted Energy Sales – Gross Load to Net Load

Year	Gross Retail Sales	Energy Efficiency	Rooftop Solar	Electric Vehicles	Voltage Control (IVVC)	Critical Peak Pricing (CPP)	Net Retail Sales
2023	45,224	(377)	(64)	44	(39)	(1)	44,787
2024	45,677	(622)	(93)	81	(78)	(1)	44,962
2025	45,932	(860)	(116)	132	(395)	(2)	44,691
2026	45,844	(1,089)	(139)	205	(398)	(3)	44,418
2027	45,913	(1,308)	(166)	305	(402)	(5)	44,337
2028	46,067	(1,507)	(194)	436	(406)	(6)	44,390
2029	46,265	(1,674)	(222)	587	(409)	(9)	44,537
2030	46,431	(1,810)	(251)	755	(413)	(10)	44,702
2031	46,667	(1,900)	(280)	937	(417)	(12)	44,995
2032	46,911	(1,931)	(310)	1,135	(420)	(14)	45,371
2033	47,136	(1,922)	(339)	1,341	(424)	(15)	45,776
2034	47,380	(1,894)	(369)	1,562	(428)	(15)	46,235

Year	Gross Retail Sales	Energy Efficiency	Rooftop Solar	Electric Vehicles	Voltage Control (IVVC)	Critical Peak Pricing (CPP)	Net Retail Sales
2035	47,648	(1,846)	(400)	1,794	(432)	(18)	46,745
2036	47,936	(1,780)	(433)	2,043	(436)	(19)	47,311
2037	48,207	(1,677)	(463)	2,290	(442)	(20)	47,895

Note: Values are at meter.

Table 3-M: Summary of the Load Forecast Without UEE Programs and Excluding any Impacts from Demand Reduction Programs

Year	Summer (MW)	Winter (MW)	Energy (GWh)
2023	12,726	14,254	64,636
2024	12,841	14,477	65,263
2025	12,931	14,517	65,402
2026	13,014	14,503	65,534
2027	13,141	14,652	65,858
2028	13,160	14,617	66,354
2029	13,269	14,812	66,856
2030	13,326	14,788	67,359
2031	13,477	14,958	67,926
2032	13,589	15,031	68,625
2033	13,723	15,135	69,234
2034	14,101	15,218	69,902
2035	14,192	15,513	70,607
2036	14,330	15,544	71,374
2037	14,513	15,735	72,097
Avg. Annual Growth Rate	0.9%	0.7%	0.8%

Figure 3-G: Load Duration Curve without Energy Efficiency Programs and Before Demand Reduction Programs

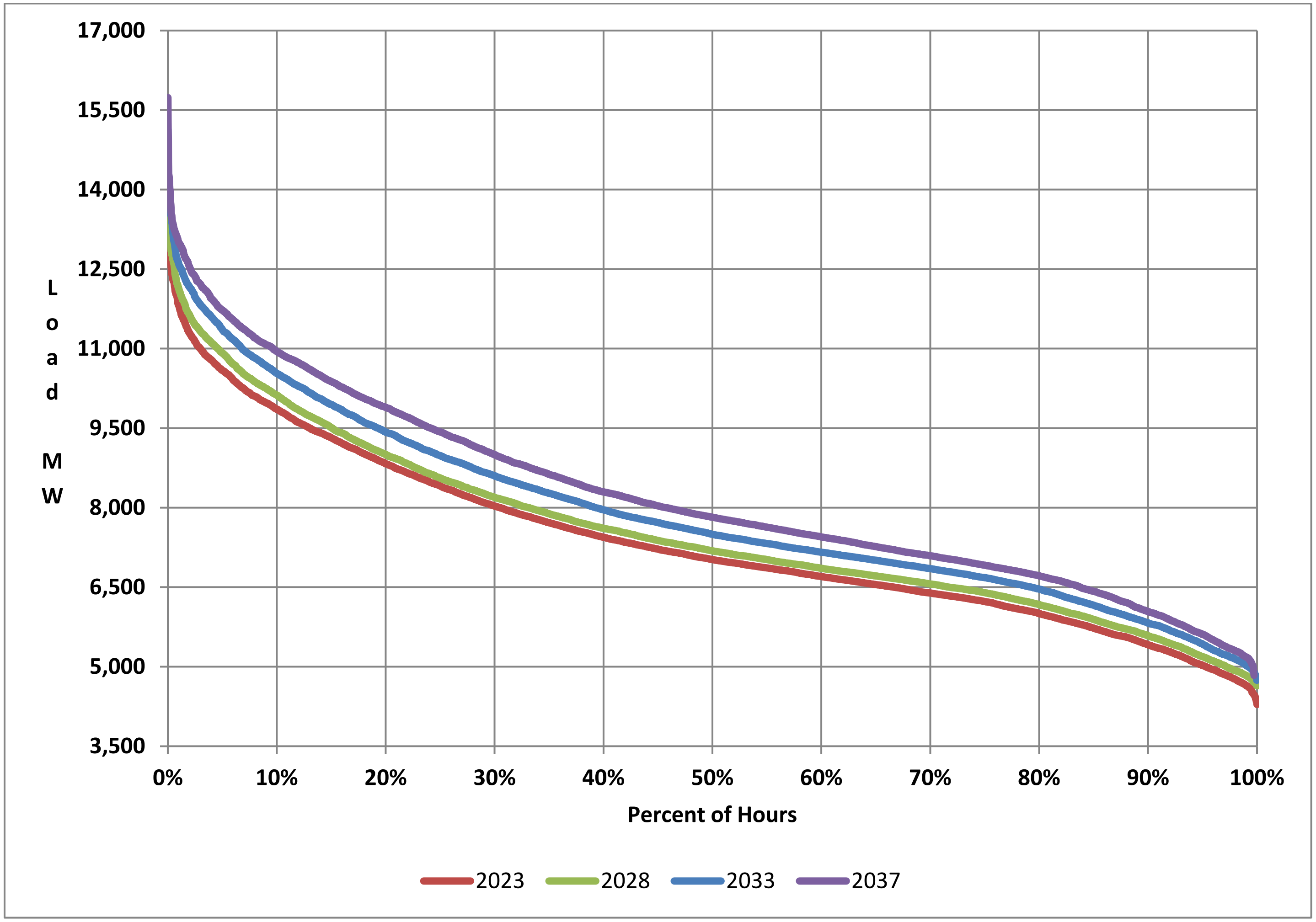
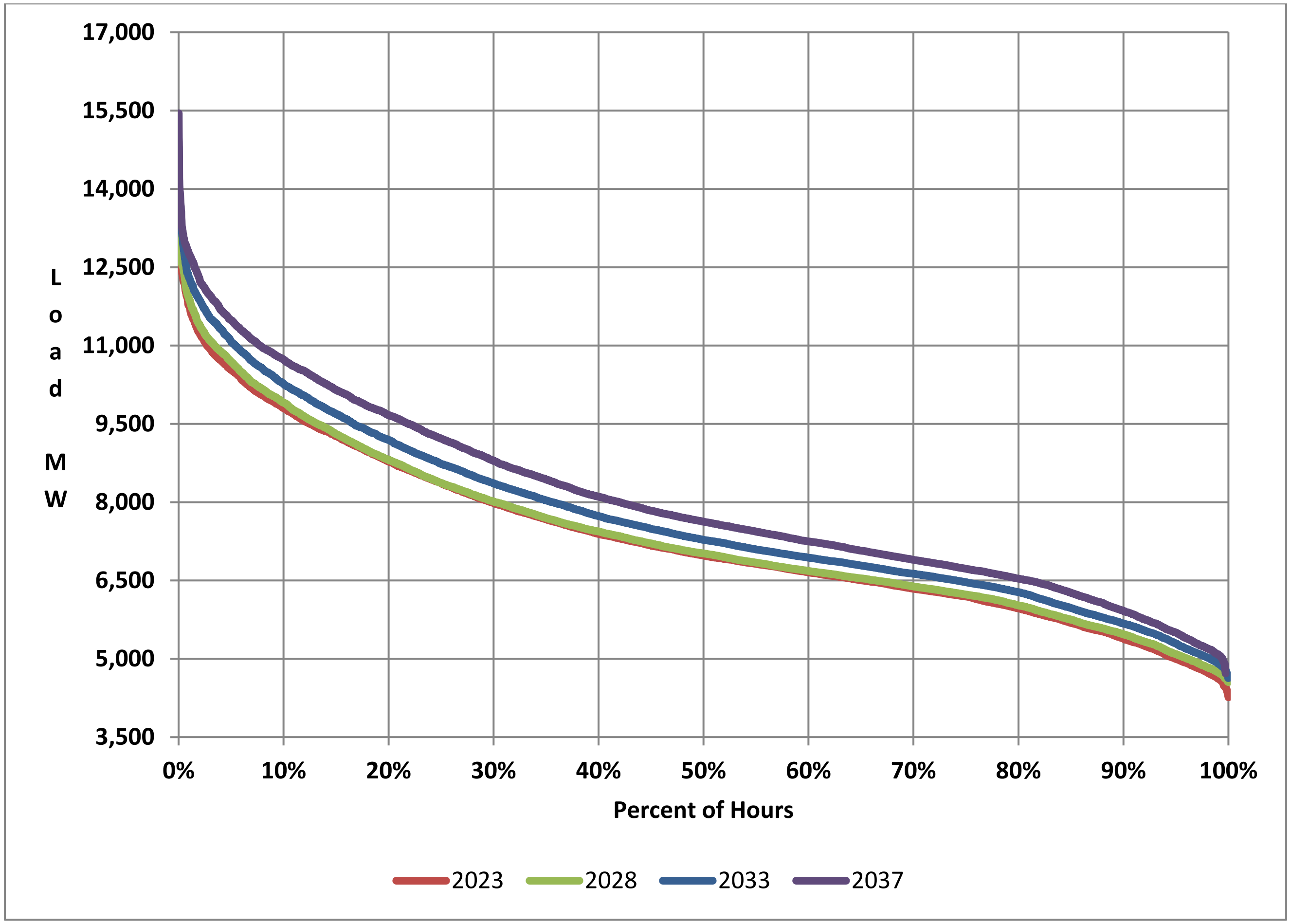


Table 3-N: Summary of the Load Forecast with UEE Programs and Excluding any Impacts from Demand Reduction Programs

Year	Summer (MW)	Winter (MW)	Energy (GWh)
2023	12,655	14,205	64,259
2024	12,725	14,386	64,641
2025	12,761	14,386	64,542
2026	12,802	14,333	64,444
2027	12,901	14,429	64,549
2028	12,876	14,361	64,847
2029	12,954	14,527	65,182
2030	13,055	14,482	65,549
2031	13,193	14,637	66,026
2032	13,306	14,706	66,694
2033	13,442	14,812	67,312
2034	13,749	14,899	68,008
2035	13,856	15,201	68,761
2036	14,005	15,243	69,594
2037	14,206	15,449	70,420
Avg. Annual Growth Rate	0.8%	0.6%	0.7%

Note: Values are at generation level. Values differ from Tables 6-F and 6-G due to 150 MW firm sale in years 2023 – 2024.

Figure 3-H: Load Duration Curve with Energy Efficiency Programs & Before Demand Reduction Programs



ENERGY EFFICIENCY, DEMAND-SIDE MANAGEMENT AND VOLTAGE OPTIMIZATION

Current Energy Efficiency and Demand-Side Management Programs

Duke Energy Progress ("DEP" or the "Company") 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.

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

Figure 4-A below shows the EE and DSM programs available through DEC as of December 31, 2021:

Figure 4-A: DEP's Available EE and DSM Programs

RESIDENTIAL EE PROGRAMS	NON-RESIDENTIAL EE PROGRAMS	COMBINED RESIDENTIAL / 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	Energy Efficient Lighting	EnergyWise℠ Home	CIG Demand Response Automation
Energy Efficiency Education	Non-Residential Smart $aver® Performance Incentive	Distribution System Demand Response (DSDR)		Large Load Curtailable Rates & Riders
Multi-Family Energy Efficiency	Small Business Energy Saver			EnergyWise® Business
Home Energy Report				
Neighborhood Energy Saver (Low-Income)				
Residential Energy Assessments				
Residential New Construction				
Residential Smart $aver® Energy Efficiency				

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.

Demand-Side Management Programs

Residential

EnergyWise^{SM} Home Program

The EnergyWise^{SM} Home Program allows DEP to install load control switches at the customer's premise to remotely control the following residential appliances:

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

For each of the appliance options above, an initial one-time bill credit of $25 following the successful installation and testing of load control device(s) and an annual bill credit of $25 is provided to program participants in exchange for allowing the Company to control the listed appliances.

EnergyWise^{SM} Home			
	Number of	2019 Capability (MW@Gen)	
Cumulative As of:	Participants*	Summer	Winter
December 31, 2021	210,980	439.6	14.2

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

The following table shows Residential EnergyWise^{SM} Home Program activations that were for the general population from January 1, 2020 through December 31, 2021.

Energywise^{sm} Home Program Activations				
Date	Start Time	End Time	Duration (Minutes)	MW Load Reduction
1/21/2020	7:00 AM	10:00 AM	180	4.4
1/21/2020	7:00 AM	10:00 AM	180	9.0
1/22/2020	7:00 AM	10:00 AM	180	4.4
1/22/2020	7:00 AM	10:00 AM	180	9.0

Energywise^{sm} Home Program Activations				
Date	Start Time	End Time	Duration (Minutes)	MW Load Reduction
7/15/2020	4:00 PM	6:00 PM	120	BYOT Test
7/17/2020	3:00 PM	5:00 PM	120	BYOT Test
9/3/2020	4:00 PM	6:00 PM	120	BYOT Test
7/1/2021	5:00 PM	7:00 PM	120	BYOT Test

EnergyWise^{SM} Home added a summer cooling Bring Your Own Thermostat ("BYOT") option in late December 2019. In December of 2020, the program shifted its focus to a year-round BYOT program, adding an electric heating requirement for program participation and aligning with a winter peak need. Customer acquisition for the BYOT program option through December 2021 is 19,000 participants.

Non-Residential

Demand Response – Curtailable Programs and Related Rate Structures

The DEP 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 2020 Nexant Market Potential Study ("MPS") 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 Progress' current curtailable programs include:

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

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

Large Load Curtailable Rates & Riders: Participants agree contractually to reduce their electrical loads to specified levels upon request by DEP. If customers fail to do so during an interruption, they receive a penalty for the increment of demand exceeding the specified level.

Energywise® Business Program

EnergyWise® Business is both an energy efficiency and demand response program for non-residential customers that allows DEP to reduce the operation of participants' air conditioning units to mitigate system capacity constraints and improve reliability of the power grid.

Program participants can choose between a Wi-Fi thermostat or load control switch that will be professionally installed for free on each air conditioning or heat pump unit. In addition to equipment choice, participants can also select the cycling level they prefer (i.e., a 30%, 50% or 75% reduction of the normal on/off cycle of the unit). During a conservation period, DEP will send a signal to the thermostat or switch to reduce the on time of the unit by the cycling percentage selected by the participant. Participating customers will receive a $50 annual bill credit for each unit at the 30% cycling level, $85 for 50% cycling, or $135 for 75% cycling. Participants that have a heat pump unit with electric resistance emergency/back up heat and choose the thermostat can also participate in a winter option that allows control of the emergency/back up heat at 100% cycling for an additional $25 annual bill credit. Participants will also be allowed to override two conservation periods per year.

Participants choosing the thermostat will be given access to a portal that will allow them to set schedules, adjust the temperature set points, and receive energy conservation tips and communications from DEP anywhere they have internet access. In addition to the portal access, participants will also receive conservation period notifications, so they can make adjustments to their schedules or notify their employees of upcoming conservation periods.

Distribution System Demand Response Program (DSDR)

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

DSDR Annual Energy Savings (MWH)							
Year	Line Loss	DSDR At T/D Bank	Total (DSDR At T/D Bank + Line Losses)	DSDR At Generator	Total (DSDR At Generator + Line Losses)	DSDR At Meter	Total (DSDR At Meter + Line Losses)
2020	28,529	3,488	32,017	3,569	32,098	3,441	31,970
2021	29,536	6,747	36,283	6,903	36,438	6,650	36,185

Since DEP's last biennial resource plan was filed on September 1, 2020, there have been 27 voltage control activations through December 31, 2021. The following table shows the date, starting and ending time, and duration for all voltage control activations in that timeframe:

Date	Start Time	End Time	Duration (H:MM)	Type
8/13/2020	9:40 AM	10:30 AM	0:50	EM1
8/27/2020	5:00 PM	8:00 PM	3:00	DSDR
9/3/2020	4:01 PM	4:24 PM	0:23	EM1
9/3/2020	5:00 PM	8:00 PM	3:00	DSDR
9/14/2020	5:00 PM	8:00 PM	3:00	DSDR
11/19/2020	6:00 AM	8:30 AM	2:30	DSDR
12/8/2020	7:15 PM	9:30 PM	2:15	DSDR
12/10/2020	6:00 AM	8:30 AM	2:30	DSDR
12/16/2020	8:53 AM	9:50 AM	0:57	EM1
1/12/2021	6:30 AM	8:30 AM	2:00	DSDR
1/14/2021	10:44 PM	11:02 PM	0:17	EM1

Date	Start Time	End Time	Duration (H:MM)	Type
3/4/2021	6:00 AM	8:30 AM	2:30	DSDR
3/8/2021	6:00 AM	7:45 AM	1:45	DSDR
3/26/2021	7:00 AM	7:22 AM	0:21	EM1
4/14/2021	6:30 PM	9:00 PM	2:30	DSDR
4/28/2021	5:00 PM	9:00 PM	4:00	DSDR
4/29/2021	5:00 PM	9:00 PM	4:00	DSDR
5/6/2021	3:51 PM	4:16 PM	0:24	EM1
5/26/2021	4:00 PM	8:00 PM	4:00	DSDR
5/27/2021	4:00 PM	8:00 PM	4:00	DSDR
6/25/2021	7:05 PM	7:28 PM	0:22	EM1
7/29/2021	4:08 PM	8:00 PM	3:52	DSDR
7/30/2021	4:00 PM	8:00 PM	4:00	DSDR
8/24/2021	4:00 PM	8:00 PM	4:00	DSDR
8/30/2021	4:00 PM	8:00 PM	4:00	DSDR
8/31/2021	4:00 PM	8:00 PM	4:00	DSDR
12/9/2021	6:02 AM	8:30 AM	2:28	DSDR

Future EE and DSM Programs

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

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

EE and DSM Program Screening

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

The analysis of energy efficiency and demand-side management cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: Utility Cost Test ("UCT"), Rate Impact Measure ("RIM") Test, Total Resource Cost ("TRC") Test and Participant Test. 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, DEP commissioned a new EE Market Potential Study to obtain new estimates of the technical, economic, and achievable potential for EE savings within the DEP service area. The final reports (one for South Carolina and one for North Carolina) were prepared by Nexant Inc. and issued in May 2020 with a final revision completed in June 2020.

In 2021, DEP again retained Resource Innovations (formerly Nexant) to perform a comprehensive update to the 2020 MPS to incorporate Commission required changes as well as address stakeholder and intervenor concerns. As required by PSCSC Order No. 2021-447, the MPS update uses the UCT for economic screening rather than TRC as was used in the original MPS. Additionally, the Company and Resource Innovations worked with the EE/DSM Collaborative to incorporate their feedback and allow for stakeholders to provide additions to the comprehensive measure list, provide input on program design/delivery changes, and assist the Company in identifying opportunities to overcome market barriers and maximize adoption of efficiency measures. The MPS update project is anticipated to be complete in August 2022 and all findings will assist the Company and

Collaborative in increasing market acceptance and adoption of existing and emerging energy saving technologies.

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

The MPS included projections of energy efficiency impacts over a 25-year period for Base, Enhanced and Avoided Energy Cost Sensitivity Scenarios, which were used in conjunction with expected EE savings from DEC's five-year program plan to develop the updated Base Case EE savings forecast for this IRP update.

The Base Case EE savings forecast represents a merging of the projected near-term savings from DEP's five-year plan (2021-2025) with the long-term MPS savings projections under UCT economic screening (2031-onward). Savings during the five-year period (2026-2030) between the two sets of projections represents a merging of the two forecasts to ensure a smooth transition. Additionally, the cumulative savings projections include 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 updated Base Case forecast of all DEP EE programs implemented since 2008 on a Net of Free Riders basis. The Company assumes total EE savings will continue to grow on an annual basis throughout the planning, however, the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan. Please note that this table includes a column that shows historical EE program savings from the inception of the EE programs in 2008 through the end of 2021, which accounts for an additional 2,932 GWh of net energy savings.

The following forecast is presented without the effects of "roll off":

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 2008
2008-21		2,932,470

Year	Annual MWh Load Reduction - Net	
	Including Measures Added In 2020 and Beyond	Including Measures Added Since 2008
2022	396,784	3,329,254
2023	645,996	3,578,466
2024	887,686	3,820,156
2025	1,122,459	4,054,929
2026	1,348,268	4,280,738
2027	1,562,440	4,494,910
2028	1,748,391	4,680,861
2029	1,906,121	4,838,591
2030	2,035,629	4,968,100
2031	2,136,917	5,069,387
2032	2,209,984	5,142,454
2033	2,266,583	5,199,053
2034	2,320,664	5,253,134
2035	2,372,394	5,304,865
2036	2,422,144	5,354,614
2037	2,469,626	5,402,096

*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 Chapter 3 – Electric Load Forecast. The tables below provide the projected summer and winter peak MW load impacts of all current and projected DEP DSM programs.

Projected Mw Load Impacts of DSM Programs

Year	Winter Peak MW Reduction					
	EnergyWise Home	CIG Demand Response	Large Load Curtailable	EnergyWise For Business	Advanced Demand Response (ADR)	Total Winter Peak
2022	5	18	224	1	0	248
2023	38	20	226	3	2	288
2024	51	21	228	3	3	307
2025	65	23	231	3	5	327
2026	80	25	233	4	8	349
2027	96	25	235	4	12	372
2028	115	25	235	5	16	395

Year	Winter Peak MW Reduction					
	EnergyWise Home	CIG Demand Response	Large Load Curtailable	EnergyWise For Business	Advanced Demand Response (ADR)	Total Winter Peak
2029	136	25	235	5	19	420
2030	160	25	235	6	22	447
2031	185	25	235	6	24	476
2032	212	25	235	7	26	504
2033	239	25	235	7	27	532
2034	254	25	235	8	28	549
2035	288	25	235	8	28	584
2036	307	25	235	8	28	603
2037	310	25	235	9	29	606

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

Projected MW Load Impacts of DSM Programs

Year	Summer Peak MW Reduction					
	EnergyWise Home	CIG Demand Response	Large Load Curtailable	EnergyWise For Business	Advanced Demand Response (ADR)	Total Summer Peak
2022	394	34	242	7	0	676
2023	424	37	244	12	3	720
2024	435	40	246	13	6	739
2025	446	43	249	11	9	758
2026	458	44	251	13	14	779
2027	469	44	252	14	19	798
2028	481	44	252	15	24	816
2029	492	44	252	16	28	833
2030	502	44	252	18	32	848
2031	511	44	252	19	35	861
2032	518	44	252	20	36	871
2033	525	44	252	22	37	880
2034	530	44	252	23	38	887
2035	534	44	252	24	39	893
2036	538	44	252	25	39	898
2037	540	44	252	26	39	901

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

Programs Evaluated but Rejected

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

Current and Anticipated Consumer Education Programs

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

- On-Line Account Access
- "Lower My Bill" Toolkit
- Online Energy Saving Tips
- Energy Resource Center
- Large Account Management
- Business Energy Advisors/ Web page
- Community Events
- Energy Efficiency Engineers
- Virtual Energy Assessments
- New Construction Energy Efficiency Design Assistance
- Newsletters

On-Line Account Access

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

"Lower My Bill" Toolkit

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

Online Energy Saving Tips

DEP has been providing tips on how to reduce home energy costs since approximately 1981. DEP's web site includes information on household energy wasters and how a few simple actions can increase efficiency.

Energy Resource Center

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

Large Account Management

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

Business Energy Advisors/ Web Page

Business Energy Advisors ("BEA's") provide guidance for commercial and industrial energy needs. They implement a holistic approach to solving customer's energy problems. The approach includes developing and leveraging customer relationships to deliver high quality solutions to SMB customers through a portfolio of products and services that drive customer engagement and loyalty. BEA's portfolio focus primarily on customers with $60,000-$250,000 annual electricity spend. In addition, BEA's assist Large Account Managers ("LAM") with EE solutions as well as leads and inquiries coming from other departments including the Customer Call Center.

Community Events

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

Energy Efficiency Engineers

Energy Efficiency Engineers ("EEE") are available to work with Duke Energy's non-residential sector largest customers to review, evaluate, and provide guidance with customer energy efficiency projects. The EEE has the energy efficiency knowledge to interact with customers, customer engineers and vendors. EEEs also educate customers on program requirements and processes, the identification of potential projects, the evaluation of data and measures, and the calculations required for the identified projects.

Virtual Energy Assessments

A building is the face of any organization, and it makes an important impression. A virtual assessment is an ideal service for medium and large facilities to take control of their energy consumption – driving down operational costs, increasing efficiency, meeting sustainability goals and addressing aging infrastructure. Using state-of-the-art software, DEP's innovative approach to energy assessments will jump-start you toward your goals. Instead of taking months analyzing data, a virtual assessment can be completed in only a few weeks. Less engineering time and more technology free up resources that can be put toward projects that will save for years to come.

New Construction Energy Efficiency Design Assistance

Duke Energy has a dedicated team ready to help businesses integrate energy saving systems into existing buildings and new construction. The DEP team will work with you and your staff to provide cost-effective, energy efficiency system design options that will reduce long-term operating costs. DEP will provide energy consulting services, whole building energy modeling, system design options for you to choose from with estimated savings and cost/payback metrics, and then provide assistance with the Smart $aver® Incentive Application process.

Newsletters

Duke Energy uses Questline to send regular newsletters to small, medium, large businesses, and trade allies with current articles focused on the importance of energy efficiency. The newsletters offer tools and contacts to help in the Smart $aver application process.

Discontinued Consumer Education Programs

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

Integrated Volt-Var Control

Program Description

Voltage Optimization performed through a program called Integrated Voltage/VAR Control ("IVVC") is the coordinated control of substation and power line equipment to manage voltage and power factor 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.

DEP first rolled out the Distribution System Demand Response ("DSDR") program in July 2014 across 97% of the eligible circuits as a peak shaving resource, allowing system operators to lower voltages across selected circuits during times of high energy demand, delaying the need for peaking generation assets. IVVC is part of the proposed Duke Energy Carolinas Grid Improvement Plan and in the meantime, DSDR will continue to operate as planned as a peak shaving resource until it is fully rolled into IVVC in 2025.

DEP is currently working to expand the capabilities of DSDR beyond peak shaving by developing another solution that focuses on continuous megawatt-hour ("MWh") reductions (energy savings) across 90% of the hours in a year not classified as peak. A centralized Distribution Management System ("DMS") will control both CVR and peak shaving modes. The original assumption was that a transition between operational modes was not possible but based on updated assumptions, DEP does not expect that changing the predominant operational strategy from DSDR to CVR will reduce peak shaving capability available today.

The new DMS in place today has the capability to transition between different modes of operation. Therefore, coming out of CVR would allow the system to return to a steady state that supports the current levels of peak shaving. Enhancements to the DMS and field devices will provide flexibility for both capacity and energy-saving capabilities while preserving options for efficient management of the grid.

The DEP CVR plan targets an estimated 2% voltage reduction. Based on initial testing, DEP will be using an average CVR factor of 0.7. A voltage reduction of 2% driven by CVR technology roughly equates to a 1.4% reduction in load for CVR-enabled circuits.

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

DEP DSDR Conversion to Year-Round CVR Annual Estimated Energy Reduction (kWh) (90% Of The Hours On Distribution Retail Circuits)*		
Year	**DSDR To CVR Deployment (%)**	**Total Reduction (kWh)***
2022	0%	0
2023	10%	38,777,000
2024	20%	78,252,000
2025	100%	394,782,000
2026	100%	398,335,000
2027	100%	401,920,000
2028	100%	405,537,000
2029	100%	409,187,000
2030	100%	412,870,000
2031	100%	416,586,000
2032	100%	420,335,000
2033	100%	424,118,000
2034	100%	427,935,000
2035	100%	431,786,000
2036	100%	435,673,000

*(Energy reduction does not account for system losses upstream of distribution retail substations)

DEP IVVC Annual Estimated Demand Reduction (kW)* Peak Shaving Mode Approximately ≤10% of the Hours		
Year	**IVVC Deployment (%)**	**Total Reduction (kW)***
2022	0%	0
2023	10%	159,505
2024	20%	160,202
2025	100%	161,111
2026	100%	162,489
2027	100%	163,771
2028	100%	165,219
2029	100%	166,583
2030	100%	167,747
2031	100%	170,160
2032	100%	172,025
2033	100%	173,255

DEP IVVC Annual Estimated Demand Reduction (kW)* Peak Shaving Mode Approximately ≤10% of the Hours		
Year	**IVVC Deployment (%)**	**Total Reduction (kW)***
2034	100%	175,443
2035	100%	177,137
2036	100%	179,544

*(Demand reduction does not account for system losses upstream of distribution retail substations)

RENEWABLE ENERGY AND ENERGY STORAGE RESOURCES

In this IRP Update, Duke Energy Progress ("DEP" or the "Company") has updated its assumptions regarding the forecast for solar and battery storage expected to be operational over the planning horizon ("forecasted solar" and "forecasted storage"), as well as the cost and operational assumptions underlying the solar and other renewable resources available to be selected through the modeling process. Solar development has benefited from a long history of supportive policies, resulting in significant growth of the industry in the Carolinas. As of December 31, 2021, approximately 4,350 megawatts ("MW") of utility-scale solar was connected on the DEP and DEC systems. North Carolina ranked fourth in the country in total solar capacity online as of 2021 while South Carolina ranked 14th.[1]

Supportive policies including competitive procurement of renewable energy and customer programs now being implemented under North Carolina Session Law 2017-192 ("NC HB 589") have contributed to the amount of solar projected to be operational during the first several years of the planning horizon on the Company's system. Longer-term growth of solar, battery storage, and other renewables will be driven by trends in technology costs, customer needs for clean energy solutions, as well as supportive federal and state policies, such as extension of the federal investment tax credit ("ITC") and production tax credit ("PTC"), South Carolina Act 62 ("SC Act 62"), and North Carolina House Bill 951 ("NC HB 951").

The following key assumptions regarding renewable energy were included in the 2022 SC IRP Update:

- All future solar is assumed to be single-axis tracking with bifacial solar panels.
- Annual interconnection limit of 750 MW/year solar beginning by year-end 2026.
- 300 MW/year wind resources available for selection by year-end 2028 across DEP and DEC.
- "Forecasted solar" has been updated consistent with current expectations of solar development pursuant to existing regulatory requirements.

[1] Solar Energy Industries Association State-By-State Map, available at https://www.seia.org/states-map.

- All solar capacity under NC HB 589 Competitive Procurement of Renewable Energy ("CPRE") program is assumed to be procured and in service by year-end 2025 with 160 MW of the total 1,781 MW located in DEP.
- Renewable and storage resources that may be selected by the model in DEP include: controllable utility owned and operated solar, $38/MWh PPA solar, solar paired with storage, onshore wind, offshore wind, and stand-alone battery storage.

Overview of Results

Based on the assumptions above, some of the key renewable and storage modeling results include:

- Installed solar capacity increases in DEP from 3,561 MW by the end of 2022 to 6,490 MW in 2037.
- Incremental standalone storage additions selected totaling 1,260 MW.
- Neither solar paired with storage, nor onshore or offshore wind, are selected in the plan.
- In the alternative case that allows 100% of solar selected to be $38/MWh PPA solar, the model selects the maximum available solar in eight of the twelve years that the option is available.

Overview of Forecasted Solar

"Forecasted" solar in the 2022 SC IRP Update includes certain solar resources that are expected to be developed pursuant to existing regulatory requirements and programs in the Carolinas. Similar to the 2020 Modified IRP, the term "Designated" refers to solar that is operational today or that has an executed purchase power agreement ("PPA") but is not yet operational. "Mandated" refers to solar that is not yet operational and has not entered into a PPA, but which is required pursuant to regulatory obligations. "Undesignated" refers to all other solar resources, including those that are selected by the model.[2] The 2022 IRP Update includes an update to the Designated and Mandated categories of solar, based on existing conditions as of February 2022. The Companies have not included any solar expected from the upcoming 2022 Solar Procurement as "forecasted solar," as certainty around the volumes associated with that resource procurement will not be known until later in 2022.

Solar Modeling Assumptions

The 2022 SC IRP Update includes several updates to operational assumptions for solar resources that are available to be selected by the model. Table 5-A below summarizes key solar assumptions included for selectable solar:

[2] Expiring "Designated" solar PPAs are assumed to be replaced in kind and are reflected as "Undesignated" at the end of the contract period.

Table 5-A: Utility Owned and Third-Party PPA Standalone Solar Modeling Assumptions for DEP

Modeling Parameter	
Build Increments	75 MW AC
DC / AC Ratio	1.4
Capacity Factor	28.5%
Dispatchability	Fully Curtailable Down
First Year Available for Model Selection	YE 2026

Standalone solar included in the 2022 SC IRP Update continues to reflect single-axis tracking configuration as was included in the 2020 Modified IRP. An additional modification made in this IRP Update is the assumption that future solar is designed with bifacial panels that further increase the energy output of solar facilities.

Additionally, the Companies assumed, for modeling purposes, that up to 60% of future solar would be located in the DEP service territory with the remaining 40% assumed to be located in DEC which reflects the Companies' current expectations of the location of future solar development.

Based on current timelines for interconnection study and construction of required upgrades to interconnect to the grid, the Company estimates that solar resources entering the interconnection process in 2022 would be operational no earlier than 2026. Accordingly, the first year that selectable solar resources are available in the model is 2026.

750 MW Per Year Solar Interconnection Constraint

Consistent with the Commission's directives regarding the volume of solar expected to be interconnected on an annual basis, the 2022 SC IRP Update includes a 750 MW per year constraint on the amount of solar and solar paired with storage that can be selected across DEP and DEC. The 2022 SC IRP Update includes the cost assumed to enable 750 MW per year of solar interconnections, and future IRPs will reflect the Company's estimates of the costs for connecting additional solar. DEP and DEC are also actively working to identify new practices to advance interconnection timelines, as well as, evaluating both the cost and scope of proactive transmission projects needed to increase the annual connections of solar and other resources. While the Companies have assumed a 750 MW annual constraint on the interconnection of solar and storage resources for purposes of this 2022 SC IRP Update, evolving transmission planning and generator interconnection practices may enable increased solar interconnection. Duke Energy will continue to analyze that pace at which new solar can be interconnected in DEC and DEP and reflect any changes to this planning assumption in future IRPs.

Selectable $38/MWh PPA Option

Consistent with the Commission's directives in Order Nos. 2021-447 and 2022-332, the Company has included a $38/MWh PPA option, which the model may select as 50% of the solar available on an annual basis. Additionally, the Company included an alternative case to evaluate 100% of future selectable solar resources being available at the $38/MWh PPA price.

Certain factors suggest that $38/MWh no longer reflects market prices for a 20-year PPA in the Company's service territory, including the overall significant volatility in the solar marketplace today and the anticipated sunsetting of the solar ITC (which has yet to be extended as of June 2022). The Company will gain more market intelligence regarding PPA prices in the Carolinas through the 2022 Solar Procurement, which commenced in June 2022 and is seeking to procure longer-term 25-year controllable solar PPAs. The Company also expects to gain more clarity on federal tax policy and solar panel prices in the coming months and years. As this information is known, the Company will update solar PPA price assumptions in its next comprehensive IRP.

Energy Storage Overview and Forecast

Energy storage is already contributing to the Company's resource mix today and will serve in the future to support additional deployment of intermittent solar resources and act as an important dispatchable resource supporting future coal plant retirements. For over a decade, the Companies have been piloting emerging battery storage technologies at several sites in the Carolinas.

A summary of all energy storage currently installed in DEP is presented in Table 5-B below.

Table 5-B: Energy Storage Systems Located in DEP

System	Location	Type of System	In-Service Date	Size
Mt. Sterling Microgrid	Haywood County, NC	Battery Storage	2017	95 kWh
AVL Rock Hill	Buncombe County, NC	Battery Storage	2020	9 MW
Hot Springs Microgrid	Madison County, NC	Battery Storage	2021	4 MW

In addition to the Company's existing storage resources, approximately 160 MW of 1- and 2-hour battery storage and 55 MW of longer duration storage are included as forecasted resources that represent inflight projects on the DEP system. This represents a limited amount of grid-connected battery storage projects that 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.

While there are various types of storage technologies, in the near term, the Company plans to deploy megawatt-scale electrochemical batteries and continue to partner with diverse suppliers who can provide the latest battery technology expertise and resources. DEP will simultaneously continue evaluation of new long-duration storage technologies, including their cost, timing of commercial viability, and value to the grid.

Energy Storage Modeling Assumptions

Energy storage included in the 2022 SC IRP Update as a selectable resource includes both stand-alone storage and solar paired with storage across a range of durations.

Table 5-C below summarizes the storage options that were included in the model:

Table 5-C: Energy Storage Options in 2022 SC IRP Update

Stand-alone Storage	Solar paired with Storage
60 MW / 240 MWh	75 MW solar + 20 MW / 80 MWh battery
60 MW / 360 MWh	75 MW solar + 40 MW / 80 MWh battery
50 MW / 400 MWh	

DEP continues to include solar paired with storage options for selection in the capacity expansion model. For the 2022 SC IRP Update, DEP added a 2-hour battery paired with solar option to be selected along with the 4-hour battery paired with solar option that was available in the 2020 Modified IRP.

Table 5-D: Solar Paired with Storage (50% Battery Ratio) Modeling Assumptions for DEP

Modeling Parameter	
Fuel	N/A
Build Increments	75 MW AC
DC / AC Ratio	1.6
Capacity Factor	33.5%
Battery Power Capacity	40 MW
Battery Storage Capacity	80 MWh
Dispatchability	Fully Curtailable Down

Table 5-E: Solar Paired with Storage (25% Battery Ratio) Modeling Assumptions for DEP

Modeling Parameter	
Fuel	N/A

Modeling Parameter	
Build Increments	75 MW AC
DC / AC Ratio	1.6
Capacity Factor	32.7%
Battery Power Capacity	20 MW
Battery Storage Capacity	80 MWh
Dispatchability	Fully Curtailable Down

NREL ATB Low Battery Storage Costs

Consistent with PSCSC Order No. 2022-332, the Company's selectable battery storage resource prices are consistent with the "Advanced Costs" assumption from the 2021 NREL Annual Technology Baseline ("ATB") report. The NREL ATB Advanced costs are the lowest battery costs in the 2021 report and do not reflect the current supply chain constraints and other factors that are driving battery storage costs higher in the short-term. For the 2023 comprehensive IRP, the Company will seek to incorporate updated market data as it becomes available in order to better align planning assumptions with current market realities for battery storage.

Wind Modeling Assumptions

As in the 2020 SC Modified IRP, onshore wind is included as a selectable resource in DEP, which is available in the model as high-capacity factor wind along the Carolinas coast.

DEP also includes offshore wind as a selectable resource in the model. Due to its location off the Carolinas coast, this resource is only available for DEP to select. Costs assume generic offshore wind turbine facility technology with costs for transmitting the energy from the offshore wind facility to a DEP service territory interconnection point, based on DEP-specific assumptions. Developing offshore wind depends on winning very select lease auctions. The Carolina Long Bay auction was held by the Bureau of Ocean Energy Management ("BOEM") on May 11, 2022, and Duke Energy Renewables Wind, LLC prequalified as an able bidder for the auction. Based on the results of the auction, Duke Energy Renewables Wind, LLC, an unregulated affiliate of Duke Energy, is now the lessee of the renewable lease, OCS-A 0546.[3]

[3] U.S Dep't of the Interior, Bureau of Ocean Energy Management, Carolina Long Bay, https://www.boem.gov/sites/default/files/documents/renewable-energy/state-activities/Commercial Lease OCS-A 0546.pdf.

2022 SC IRP Update Renewable Energy Resource Selection

The details of the renewable energy and battery storage resource additions identified in this 2022 DEP SC IRP Update are summarized in Table 5-F below.

Solar is first allowed to be selected in the model in 2026, and the model selects most of the $38/MWh PPA solar in 2026, and all of the available PPA solar in 2027 and beyond. By the end of the planning horizon in 2037, 2,625 MW of solar is selected, all of which is the $38/MWh PPA option. In the alternative case, which includes all solar as $38/MWh PPA solar, the model does not select any solar in 2026, 2028, 2029 or 2031 in DEP, but selects all available solar in all other years. By the end of the planning horizon, 3,600 MW of solar is selected in the 100% $38/MWh PPA case. Solar paired with storage is not selected in either case.

Standalone storage, priced at the NREL ATB Advanced prices, is economically selected in DEP beginning in 2027. By the end of the planning horizon, 1,200 MW of incremental 4-hour, standalone storage is selected by the model along with 60 MW of 6-hour storage. In the alternative case, where 100% of available solar is the $38/MWh option, storage selection is also selected in 2027 and the total amount of storage selected is 1,260 MW of 4-hour storage.

Wind resources are not selected in the 2022 SC IRP Update.

Table 5-F: DEP Base Case Total Renewables and Energy Storage (MW)

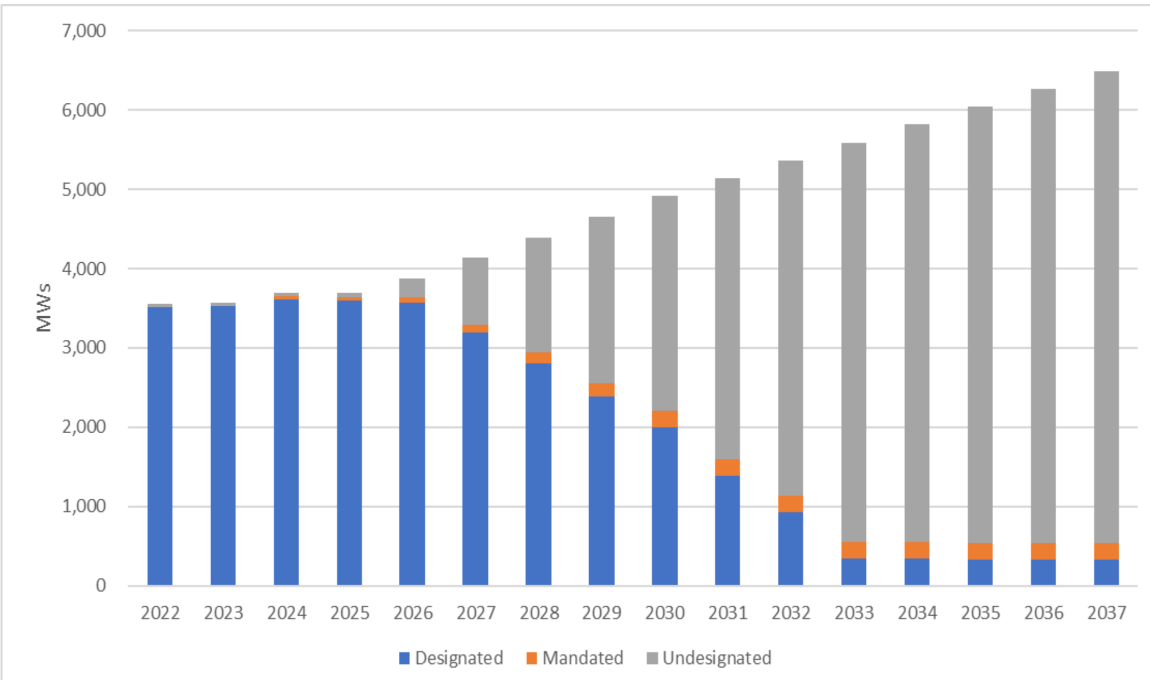
Year	Solar Only	Solar With Storage	Biomass / Hydro	Wind	Stand Alone Storage	Total Renewables & Storage
2022	3,561	0	141	0	24	3,726
2023	3,571	0	128	0	54	3,753
2024	3,690	0	128	0	209	4,028
2025	3,690	0	120	0	209	4,019
2026	3,875	0	120	0	237	4,232
2027	4,135	0	116	0	417	4,668
2028	4,395	0	63	0	777	5,235
2029	4,655	0	44	0	777	5,476
2030	4,915	0	44	0	897	5,856
2031	5,140	0	43	0	897	6,080
2032	5,365	0	41	0	1,017	6,423
2033	5,590	0	40	0	1,077	6,708
2034	5,815	0	40	0	1,497	7,353
2035	6,040	0	40	0	1,497	7,578
2036	6,265	0	40	0	1,497	7,803
2037	6,490	0	40	0	1,497	8,028

Year	Solar Only	Solar With Storage	Biomass / Hydro	Wind	Stand Alone Storage	Total Renewables & Storage

Note: Data presented on a year-end basis. Capacity listed is solar nameplate capacity.

Figure 5-A below shows DEP's solar resource additions by designated, mandated, and undesignated categories, which are explained above.

Figure 5-A: DEP Cumulative Solar Capacity



Factors Impacting Future Renewable Energy and Storage Growth

The low cost assumptions for solar PPAs and battery storage drive significant volumes of solar and battery storage to be selected as economic by the model. Given the disparity between the costs included in the modeling assumptions and the costs of the solar and storage resources available for purchase in the market today, the practical applicability of these modeling results is limited. Numerous economic factors challenge predictability in renewable energy development at this time, including ongoing supply chain constraints and the uncertainty regarding future policies on solar panel tariffs, which will continue to strain the availability of the market to provide solar and battery resources at prices that are consistent with those prices the Commission has required for modeling purposes in this 2022 SC IRP Update.

In the 2023 comprehensive IRP, the Company will further evaluate these forecasted costs to develop assumptions that are more reflective of the prevailing market conditions at that time. Solar resources that are expected to be procured pursuant to other regulatory requirements, such as the 2022 solar procurement underway now, will also be included. Moreover, the Company anticipates updating its Green Source Advantage Program and other clean energy programs for large customers, which will likely impact the volumes of solar resources shown in future IRP modeling.

DEVELOPMENT OF RESOURCE PLAN

Duke Energy Progress ("DEP" or the "Company") continues to plan to a winter planning reserve margin criterion in the IRP process as further discussed below. To meet the future needs of DEP's customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, DEP develops a load forecast of cumulative energy sales and hourly peak demand. To determine total resources needed, the Company considers the peak demand load obligation plus a 17% minimum winter planning reserve margin. The projected capability of existing resources, including generating units, EE and DSM, renewable resources and purchased power contracts is measured against the total resource need. Any deficit in future years will be met by a mix of additional resources that reliably and cost-effectively meet the load obligation and planning reserve margin while complying with all environmental and regulatory requirements. A high-level representation of the IRP process is represented in Figure 6-A.

Figure 6-A: Simplified IRP Process

Resource Adequacy and Planning Reserve Margin

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 the planning 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

DEP and DEC retained Astrapé Consulting to conduct new resource adequacy studies to support development of the Companies' 2020 IRPs.[3] Astrapé analyzed the planning reserve margin needed to provide an acceptable level of physical reliability based on the industry standard "one-day-in-ten-years" Loss of Load Expectation ("LOLE") metric (or, 0.1 LOLE). This standard is interpreted as one firm load shed event every 10 years due to a shortage of generating capacity.

As described in the resource adequacy studies included and evaluated as part of the 2020 IRPs, Astrapé recommended that DEP and DEC continue to maintain a minimum 17% winter reserve margin for IRP planning purposes. Consistent with this outcome, DEP used a minimum 17% winter reserve margin in the development of the 2022 SC IRP Update. The 2020 DEP Resource Adequacy Study Report was provided as Attachment III to the Company's 2020 IRP.

Effective Load Carrying Capability of Renewable and Storage Resources

The IRP Update includes the addition of significant levels of variable renewable resources and energy-limited storage resources to the system. The effective load carrying capability ("ELCC") or "capacity value" of a resource can be thought of as a measure of the reliable capacity contribution of a resource being added to an existing generation portfolio. Conventional thermal resources are typically dispatchable and available to meet load when not in forced outage or planned maintenance. However, due to the variable energy nature of solar and wind resources and the energy-limited nature of storage resources, it is critical to understand the reliable capacity contributions of these resources in the generation planning

---

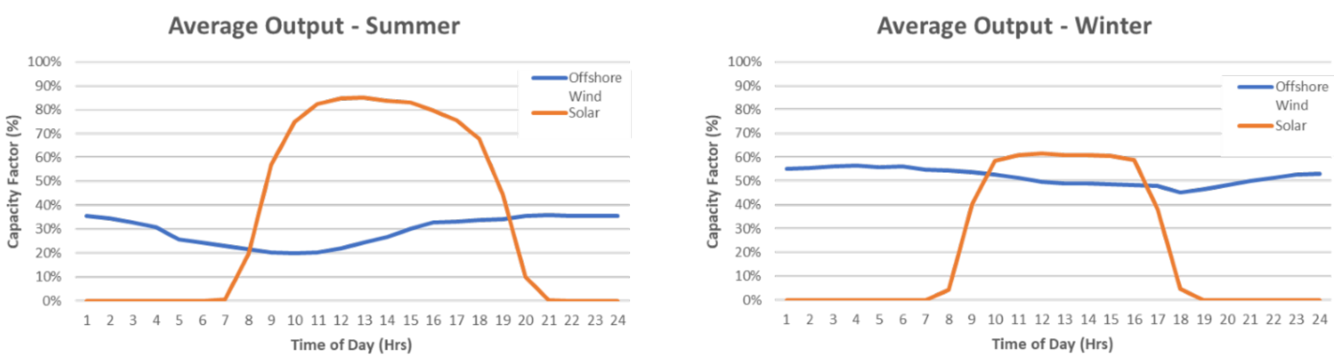
[1] NERC defines "Adequacy" as "[t]he ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components." N. American Elec. Reliability Corp., 2021 Long-Term Reliability Assessment, at 11, *available at* . https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

[2] Total resources reflect contribution to peak values for variable 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 has conducted several Resource Adequacy Studies and Effective Load Carrying Capability Studies for DEP and DEC in recent years.

process. For example, winter peak load for DEP occurs in the early morning and late evening when the solar output is low, while peak loads in the summer occur across the afternoon and early evening which is more coincident with solar output. Like solar, onshore and offshore wind resources are also variable energy resources. However, deployment of wind resources can complement solar resources by providing energy to the system during overnight hours or winter months when solar energy is low or not available. Average summer and winter solar and offshore wind profiles are illustrated in Figure 6-B below, which shows the availability of wind generation during hours when solar generation is not available.

Figure 6-B: Average Offshore Wind and Solar Generation Summer and Winter Profiles, Utilized in Encompass Modeling



ELCC Study

The Commission's order requiring modifications to the Companies' 2020 Integrated Resource Plans required the Companies to make several adjustments to the solar and storage ELCC studies as outlined below.[4] This IRP Update incorporates these changes as directed by the Commission.

1. Perform surface ELCCs for solar and storage:

   To accommodate the surface ELCC, Astrapé performed solar only ELCC analyses, storage only ELCC analyses, and storage and solar aggregated ELCC analyses to ensure any synergistic benefits were included. As described in the DEC and DEP ELCC Study report being provided as Attachment I to the IRP Update, this analysis was performed over a broad range of capacity and storage durations. Previously, in the 2020 Storage ELCC Study, the storage ELCC analysis was performed with significant solar on the system, so all synergistic value was given to storage. Similar surface analyses were performed for wind and solar.

2. Use of 2035 Load Forecasts in the Analysis:

[4] South Carolina Docket Nos. 2019-224-E and 2019-225-E, Order No. 2021-447, June 28, 2021, at 87.

Utilizing the 2035 load forecast captures a larger system and provides these resources more capacity value than would be attributed to the resources if system needs were lower.[5]

3. Use higher capacity factor solar resources:

   All future solar additions were modeled as bifacial, single-axis tracking resources.

4. Incorporate the Company's Winter Peak Demand Reduction Potential Assessment:

   The Winter Peak Study, which included additional demand response programs, adds demand response capacity in both winter and summer.[6]

DEP and DEC worked with Astrapé to conduct a new ELCC study to understand the reliable capacity contributions of solar, onshore wind, offshore wind, and storage for use in the planning process. As previously noted, the ELCC or "capacity value" of a resource can be thought of as a measure of the reliable capacity contribution of a resource being added to an existing generation portfolio. The ELCC of a resource depends on many factors including the load and load shape to be served, the existing resource mix, as well as the adoption level of different resource technologies. A variable renewable resource typically exhibits declining capacity value as adoption increases since saturation occurs, and reliability events shift to periods when that particular resource is not available. The incremental capacity value of a resource may also change as the resource mix of the portfolio evolves around those resources.

Additionally, the capacity value of variable energy resources can increase as other variable energy resources are added to the system. To evaluate the "synergistic benefits" of adding portfolios of resources together, and in response to stakeholder feedback on the ELCC studies presented in support of the Companies' 2020 IRPs, Astrapé conducted an ELCC surface study rather than a standalone ELCC study where capacity values of resources are evaluated individually.

The surface study revealed that as the deployment of solar resources increases on the system, storage capacity value improves as more energy is available to charge the storage resource. Similarly, storage provides synergistic value to solar capacity value as the dispatch of stored energy can shift peak demand periods from times when solar is not available to hours when the sun is shining.

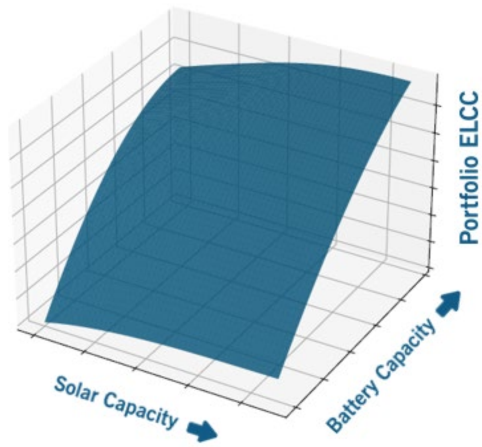
Figure 6-C below illustrates a typical ELCC surface for solar and storage with one axis representing the adoption of solar, one axis representing the adoption of storage, and the height of the surface representing the combined portfolio ELCC of the resources.

---

[5] Given this assumption, ELCCs could potentially be overstated prior to 2035.

[6] The 2020 Winter Peak Demand Reduction Potential Assessment (also referred to as the Winter Peak Study) was prepared for Duke Energy by Dunsky Energy Consulting in partnership with Tierra Resource Consultants. The objective of the study was to identify the potential for new demand response programs and measures to reduce the winter peak demand in each of the DEP and DEC systems.

Figure 6-C: Depiction of a Solar and Storage ELCC Surface



Application of ELCC Study in the IRP Update

The EnCompass model selects reliability resources in the capacity expansion process utilizing the incremental capacity value that a resource provides to the system as part of the selection process. For this reason, the ELCC results shown below represent the incremental capacity value allocated to incremental tranches of resources in the EnCompass model.

Importantly, these ELCC results reflect the “synergistic benefits” of other variable resources present on the system. The solar and storage ELCC values used in EnCompass reflect the synergistic effect that these resources have on each other’s capacity values as their deployment increases on the system. Additionally, onshore and offshore wind ELCCs were developed at increasing deployments of solar on the system in order to capture the synergistic impact that solar can have on wind capacity value. While the EnCompass model can consider a range of ELCC inputs for multiple technologies, EnCompass cannot presently use a multidimensional ELCC surface as an input. As the model attempts to optimize thousands of combinations of resource options, it can experience difficulty solving within reasonable time parameters. Attempting to integrate any such n-dimensional surface would further inhibit the model’s ability and accuracy in assessing resources. For this reason, the Companies applied discreet ELCC values for solar, storage, and wind resources that still recognize the synergistic value that these technologies can provide toward each technology’s capacity value.

Finally, as noted above, DEP is a winter planning utility and plans its system to satisfy a minimum winter reserve margin. This means that the hours in which the Company has the most risk of not meeting demand occur during the winter period. When resources are selected in the EnCompass model for the purpose of maintaining adequate reserves, the resources are selected based on their winter capacity value. As such, the tables below represent the incremental winter ELCC values for each resource in the IRP Update.

Solar ELCC

Table 6-A below represents the incremental capacity values attributed to solar resources in the EnCompass capacity expansion model. Capacity tranches are represented in megawatts ("MW").

Table 6-A: DEP Winter Solar Incremental ELCC Values

Capacity Tranche [MW]	ELCC
0 - 2,000	8%
2,001 - 3,000	5%
3,001 - 4,000	3%
4,001 - 5,000	2%
5,001 - 6,000	2%
6,001 - 8,000	2%
8,000+	2%

Storage ELCC

Table 6-B below represents the incremental capacity values attributed to standalone storage resources in the EnCompass model. The Company included a variety of storage durations for the model to select from. The incremental capacity value of the next storage asset added to the system is impacted by the total storage already on the system and the duration of the storage already on the system when the next storage asset is considered. The ELCCs in the tables below reflect that impact.

Table 6-B: DEP Standalone Storage Incremental ELCC Values

Capacity Tranche [MW]	Battery Duration	ELCC
0 – 450	4	100%
451 – 900	4	94%
901 – 1,800	4	87%
1,801 – 2,300	4	73%
2,301 – 2,800	6	85%
2,801 – 3,300	6	68%

Solar Paired with Storage ("SPS") ELCC

The capacity value of storage paired with solar was assumed to be additive between the two resources. Table 6-C below reflects the ELCC values of the total SPS facility for each of the SPS options included in the EnCompass model. For example, a 400 MW facility that is paired with 50%, 2-hour duration storage reflects a 400 MW solar plant paired with 200 MW of 2-hour storage. The ELCC of that facility is 26% or 104 MW (26% * 400 MW).

Table 6-C: DEP Winter Solar Paired with Storage Incremental ELCC Values

Capacity Tranche [MW]	% Storage Paired with Solar	Battery Duration	ELCC
0 – 900	50%	2	26%
0 – 500	25%	4	32%
501 – 1,000	25%	4	31%
1,001 – 1,500	25%	4	30%
1,501 – 2,000	25%	4	29%
2,001 – 2,500	25%	4	28%
2,501 – 3,000	25%	4	27%

Wind ELCC

Tables 6-D and 6-E below detail the capacity values for both onshore and offshore wind in the Carolinas.

Table 6-D: DEP Winter Onshore Wind Incremental ELCC Values

Capacity Tranche [MW]	ELCC
0 – 1,000	42%
1,001 – 2,000	39%
2,001 – 3,000	36%

Table 6-E: DEP Winter Offshore Wind Incremental ELCC Values

Capacity Tranche [MW]	ELCC
0 – 1,000	67%
1,001 – 2,000	62%
2,001 – 3,000	56%

Resource Technologies Considered

Resource technologies included in the 2022 IRP Update as selectable resources are listed below.

Technologies (Winter Ratings):

- Base load – 1,216 MW 2x2x1 Advanced Combined Cycle (No Inlet Chiller and Fired)
- Base Load – 285 MW Small Modular Reactor (SMR)
- Base Load – 345 MW Advanced Nuclear Reactor (AR) with Thermal Storage
- Peaking/Intermediate – 924 MW 4 x 7FA.05 Combustion Turbines (CTs)

- Storage – 60 MW / 240 MWh Li-Ion Battery (4-hour)
- Storage – 60 MW / 360 MWh Li-Ion Battery (6-hour)
- Storage – 50 MW / 400 MWh Li-Ion Battery (8-hour)
- Intermittent – 75 MW Solar PV, Bifacial and Single Axis Tracking (SAT)
- Intermittent – 75 MW Solar PV plus 20 MW / 80 MWh or 40 MW / 80 MWh Li-ion Battery
- Intermittent – 150 MW Onshore Wind
- Intermittent – 1,600 MW Offshore Wind

Costs for all technology resources have been updated for this IRP Update. The discussion below provides an overview of adjustments to the technical and operational assumptions for these resource technologies.

Combined Cycle Technology: A 2x1 advanced class CC continues to be used without any significant technology changes.

Small Modular Reactor Technology: The base technology utilized for modeling Small Modular Reactors ("SMRs") has changed, and the SMR option is intended to represent the technology as a whole rather than a specific design. The size change to smaller units allows for greater flexibility for the models.

Advanced Reactor Technology: A new technology option considered an Advanced Reactor ("AR") has been included. ARs are advanced nuclear options that have additional benefits compared to the current operating fleet and do not use light water in the design. ARs are a developing technology similar to SMRs, and significant DOE funding has been awarded to advance the technology. The first AR full scale demonstrations are expected to be online before the end of the decade, paving the way for additional deployments in the 2030s. The AR chosen for modeling includes thermal storage integrated with the design which leads to enhanced flexibility of the plant. There are many technology options considered ARs and similar to SMRs the inclusion represents the technology as a whole rather than a specific company or design.

Combustion Turbine Technology: A 4-unit F.05 Class CT continues to be used without any significant technology changes.

Energy Storage Technology: Lithium-Ion technology remains the dominant energy storage being deployed across the industry. Four-hour, 6-hour, and 8-hour options are included in the modeling. No major adjustments have been made to the energy storage information in the update.

Solar PV Technology: The major adjustment to solar PV is the assumption that panels are now bifacial instead of monofacial, which leads to an increased capacity factor. All solar PV is assumed to utilize a single axis tracking system.

Solar PV Plus Storage Technology: Similar to the solar PV change, all solar PV plus storage assumes panels are bifacial instead of monofacial in the update. The model allows for selection of two different solar plus storage options. The first option is a 20 MW (80 MWh) Li-Ion storage asset included with the solar, which is consistent with the 2020 IRP. For the 2022 IRP Update, DEP included a new storage option consisting of a 40 MW (80 MWh) storage asset.

Onshore Wind Technology: There have been no major technology changes for the onshore wind option.

Portfolio A2 Update Results

As directed by the PSCSC, this SC IRP Update provides an update to Portfolio A2 as defined in the 2020 SC Modified IRP. Portfolio A2 was developed using the assumption that no federal or state carbon policy would be adopted over the entirety of the planning horizon. In addition, the analysis that resulted in Portfolio A2 was based on certain other assumptions specified by the PSCSC in Order No. 2021-447, including the schedule used to blend market and fundamentals-based natural gas prices, the price at which third-party solar resources will be available, the future costs of energy storage resources, and others. These PSCSC-directed inputs are discussed in more detail throughout this document. It is also noted that DEP considers the non-firm energy purchases and sales associated with the joint dispatch agreement ("JDA") with DEC in the update of Portfolio A2 for the 2022 SC IRP Update.

Tables 6-F and 6-G represent the winter and summer Load, Capacity and Reserves ("LCR") tables for Portfolio A2. The updated Portfolio A2 presented in this document calls for the addition of approximately 2.7 GW of new solar and solar-plus-storage capacity, 1.5 GW of new energy storage capacity, one new combined-cycle generator (1.2 GW) and 1.8 GW of new combustion turbine capacity by 2037. These resource additions would meet growing customer load and replace 3.2 GW of retiring coal capacity. This analysis continues to assume the most economic retirement dates for the coal units developed in the 2020 IRP, as discussed in Chapter 2 – Updates to the 2020 IRP.

Table 6-F: DEP Portfolio A2 Load, Capacity and Reserves Table – Winter

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Load Forecast															
1 DEP System Winter Peak	14,255	14,478	14,519	14,505	14,655	14,620	14,816	14,794	14,965	15,039	15,145	15,228	15,524	15,556	15,747
2 Firm Sale	150	150	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(49)	(91)	(132)	(170)	(223)	(256)	(284)	(306)	(321)	(325)	(324)	(319)	(312)	(301)	(286)
4 Adjusted Duke System Peak	**14,356**	**14,537**	**14,387**	**14,335**	**14,432**	**14,365**	**14,532**	**14,487**	**14,644**	**14,714**	**14,821**	**14,909**	**15,212**	**15,255**	**15,461**
Existing and Designated Resources															
5 Generating Capacity	13,614	13,614	13,614	13,614	13,614	13,614	12,205	10,439	10,439	10,439	10,439	10,439	10,439	10,439	10,439
6 Designated Additions / Uprates	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	0	0	0	0	(1,409)	(1,766)	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	**13,614**	**13,614**	**13,614**	**13,614**	**13,614**	**12,205**	**10,439**	**10,439**	**10,439**	**10,439**	**10,439**	**10,439**	**10,439**	**10,439**	**10,439**
Purchase Contracts															
9 Cumulative Purchase Contracts	**2,668**	**2,649**	**2,636**	**2,582**	**2,584**	**2,529**	**2,530**	**2,531**	**2,530**	**2,528**	**2,527**	**2,526**	**2,526**	**2,525**	**2,525**
Non-Compliance Renewable Purchases	232	232	231	232	231	183	183	185	183	181	180	180	179	179	178
Non-Renewables Purchases	2,437	2,418	2,405	2,350	2,353	2,347	2,347	2,347	2,347	2,347	2,347	2,347	2,347	2,347	2,347
Undesignated Future Resources															
10 Nuclear															
11 Combined Cycle							1,216								
12 Combustion Turbine						1,385									462
13 Solar								11	11	11	11	11	7	7	7
14 Wind															
15 Battery						180	337		112		112	56	364		
Renewables															
16 Cumulative Renewables Capacity	**155**	**160**	**152**	**152**	**150**	**326**	**646**	**656**	**779**	**789**	**912**	**978**	**1,349**	**1,355**	**1,362**
Renewables w/o Storage	155	160	152	152	150	146	129	128	128	128	127	127	127	126	126
Solar plus Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 Combined Heat & Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 Grid-connected Energy Storage	17	30	155	0	28	0	0	0	0	0	0	0	0	0	0
19 Cumulative Production Capacity	**16,497**	**16,513**	**16,647**	**16,592**	**16,620**	**16,718**	**16,489**	**16,500**	**16,621**	**16,630**	**16,751**	**16,817**	**17,187**	**17,194**	**17,662**
Demand Side Management (DSM)															
20 Cumulative DSM Capacity	**288**	**307**	**327**	**349**	**372**	**395**	**420**	**447**	**476**	**504**	**532**	**549**	**584**	**603**	**606**
21 IVVC Peak Shaving	**160**	**160**	**161**	**162**	**164**	**165**	**167**	**168**	**170**	**172**	**173**	**175**	**177**	**180**	**182**
22 Cumulative Capacity w/ DSM	**16,945**	**16,980**	**17,135**	**17,104**	**17,156**	**17,278**	**17,076**	**17,115**	**17,267**	**17,306**	**17,457**	**17,542**	**17,948**	**17,976**	**18,450**
Reserves w/ DSM															
23 Generating Reserves	2,589	2,443	2,748	2,769	2,724	2,913	2,544	2,628	2,623	2,592	2,636	2,633	2,737	2,721	2,989
24 % Reserve Margin	**18%**	**17%**	**19%**	**19%**	**19%**	**20%**	**18%**	**18%**	**18%**	**18%**	**18%**	**18%**	**18%**	**18%**	**19%**

Table 6-G: DEP Portfolio A2 Load, Capacity and Reserves Table – Summer

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Load Forecast															
1 DEP System Summer Peak	12,727	12,842	12,935	13,019	13,145	13,168	13,278	13,339	13,487	13,595	13,727	14,101	14,178	14,316	14,497
2 Firm Sale	150	150	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Cumulative New EE Programs	(71)	(116)	(170)	(212)	(240)	(284)	(315)	(271)	(284)	(283)	(282)	(351)	(336)	(324)	(307)
4 Adjusted Duke System Peak	**12,805**	**12,876**	**12,765**	**12,807**	**12,904**	**12,883**	**12,963**	**13,068**	**13,203**	**13,313**	**13,445**	**13,749**	**13,841**	**13,991**	**14,191**
Existing and Designated Resources															
5 Generating Capacity	12,426	12,426	12,426	12,426	12,426	12,426	11,034	9,283	9,283	9,283	9,283	9,283	9,283	9,283	9,283
6 Designated Additions / Uprates	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Retirements / Derates	0	0	0	0	0	(1,392)	(1,751)	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	**12,426**	**12,426**	**12,426**	**12,426**	**12,426**	**11,034**	**9,283**	**9,283**	**9,283**	**9,283**	**9,283**	**9,283**	**9,283**	**9,283**	**9,283**
Purchase Contracts															
9 Cumulative Purchase Contracts	**3,767**	**3,725**	**3,712**	**3,673**	**3,681**	**3,633**	**3,639**	**3,646**	**3,645**	**3,643**	**3,642**	**3,642**	**3,641**	**3,641**	**3,640**
Non-Compliance Renewable Purchases	1,428	1,405	1,404	1,411	1,416	1,374	1,380	1,387	1,386	1,384	1,383	1,383	1,382	1,382	1,381
Non-Renewables Purchases	2,340	2,321	2,308	2,262	2,265	2,259	2,259	2,259	2,259	2,259	2,259	2,259	2,259	2,259	2,259
Undesignated Future Resources															
10 Nuclear															
11 Combined Cycle							1,155								
12 Combustion Turbine						1,257									419
13 Solar / Solar + Storage								9	9	9	9	8	8	8	8
14 Wind															
15 Battery						180	337		112		112	56	364		
Renewables															
16 Cumulative Renewables Capacity	**762**	**789**	**781**	**774**	**766**	**936**	**1,250**	**1,253**	**1,374**	**1,383**	**1,503**	**1,568**	**1,939**	**1,947**	**1,955**
Renewables w/o Storage	762	789	781	774	766	756	733	727	727	726	726	725	725	725	725
Solar plus Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 Combined Heat & Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 Grid-connected Energy Storage	17	30	155	0	28	0	0	0	0	0	0	0	0	0	0
19 Cumulative Production Capacity	**17,015**	**17,030**	**17,164**	**17,118**	**17,146**	**17,132**	**16,857**	**16,867**	**16,986**	**16,993**	**17,113**	**17,177**	**17,548**	**17,555**	**17,982**
Demand Side Management (DSM)															
20 Cumulative DSM Capacity	**720**	**739**	**758**	**779**	**798**	**816**	**833**	**848**	**861**	**871**	**880**	**887**	**893**	**898**	**901**
21 IVVC Peak Shaving	**188**	**189**	**190**	**191**	**193**	**195**	**196**	**198**	**200**	**203**	**204**	**207**	**209**	**211**	**214**
22 Cumulative Capacity w/ DSM	**17,923**	**17,958**	**18,112**	**18,089**	**18,137**	**18,143**	**17,886**	**17,912**	**18,048**	**18,067**	**18,197**	**18,271**	**18,649**	**18,664**	**19,097**
Reserves w/ DSM															
23 Generating Reserves	5,118	5,082	5,347	5,282	5,233	5,260	4,924	4,844	4,845	4,754	4,752	4,522	4,808	4,673	4,906
24 % Reserve Margin	**40%**	**39%**	**42%**	**41%**	**41%**	**41%**	**38%**	**37%**	**37%**	**36%**	**35%**	**33%**	**35%**	**33%**	**35%**

DEP - Assumptions of Load, Capacity and Reserves Table

The following notes are numbered to match the line numbers on the Winter Projections of Load, Capacity and Reserves tables. All values are MW (winter ratings) except where shown as a percent. Dates represented are commercial operation dates ("COD"), unless otherwise noted.

Line Item	Line Inclusion[7]
1.	Peak demand for the Duke Energy Progress System as defined in Chapter 3 – Electric Load Forecast. This line is net of rooftop solar, electric vehicles, IVVC load reductions, and net energy metering.
2.	Firm sale of 150 MW through 2024.
3.	Cumulative new energy efficiency and conservation programs (does not include demand response programs).
4.	Peak load adjusted for firm sales and cumulative energy efficiency.
5.	Existing generating capacity reflecting the impacts of designated additions, planned uprates, retirements and derates as of March 1, 2022.
6.	Designated Capacity Additions. There are no designated capacity additions scheduled for DEP.
7.	Estimated retirement dates for planning that represent most economical retirement date for coal units as determined in Coal Retirement Analysis developed in the 2020 IRP. Other units represent estimated retirement dates based on the depreciation study approved in the most recent DEP rate case, except where adjusted for reliability purposes: Roxboro Units 1-2 (1,053 MW): December 2028 Mayo Unit 1 (713 MW): December 2028 Roxboro Units 3-4 (1,409 MW): December 2027
	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 2022 SC IRP Update are for planning purposes only, unless the unit is already planned for retirement.
8.	Sum of lines 5 through 7.
9.	Cumulative Purchase Contracts from traditional resources and renewable energy resources not used for NCREPS and NC HB589 compliance. This is the sum of the next two lines.
	Non-Compliance Renewable Purchases includes purchases from renewable energy resources for which DEP does not own the renewable energy certificate (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

[7] 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.

Line Item	Line Inclusion[7]
	margin. No nuclear resources were selected in Portfolio A2.
11.	New combined cycle resources economically selected to meet load and minimum planning reserve margin.
12.	New combustion turbine resources economically selected to meet load and minimum planning reserve margin.
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. See Table 6-A provided earlier in this chapter for ELCC values of solar.
14.	New wind resources economically selected to meet load and minimum planning reserve margin. No wind resources were selected by the models in Portfolio A2.
15.	New battery storage resources economically selected to meet load and minimum planning reserve margin. See Table 6-B provided earlier in this chapter for ELCC values of energy storage.
16.	Cumulative Renewables Capacity includes forecasted renewable energy resources forecasted and model-selected renewable resources. This is the sum of the next two lines combined with the sums of lines 13 through 15.
	Renewables w/o Storage includes projected purchases from solar energy resources not paired with storage and other types of renewables.
	Solar w/ Storage includes projected purchases from solar paired with storage.
17.	Combined Heat and Power projects. There are no CHP projects are forecasted for DEP.
18.	Grid-connected energy storage additions.
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%.

PVRR Results

The present value of revenue requirement ("PVRR") for Portfolio A2 in the 2022 IRP Update for DEP is approximately $27.1 billion. PVRR is a common Integrated Resource Planning cost metric calculated by assessing all future costs associated with a given resource portfolio and discounting those future costs to customers to present day costs using the Company's weighted average cost of capital. This metric captures the cost of adding new generation as well as system production costs. These production costs include operating and maintaining the generation units, fuel costs, labor costs, and other costs to operate and maintain a reliable system. PVRR analysis is typically limited to costs associated with generating electricity to serve load, but starting in the September 2020 IRP, the Company included generic "proxy" estimates of the transmission costs associated with adding new generation and retiring existing units. Those generation-related transmission costs are included in the calculations for this IRP update as well.

Portfolio A2 Expansion Plan and Resource Mix

A graphical presentation of Portfolio A2 as represented in the above winter LCR table is shown in Figure 6-D below.

Figure 6-D: DEP Portfolio A2 Update – Winter (Nameplate for Renewables and Storage)

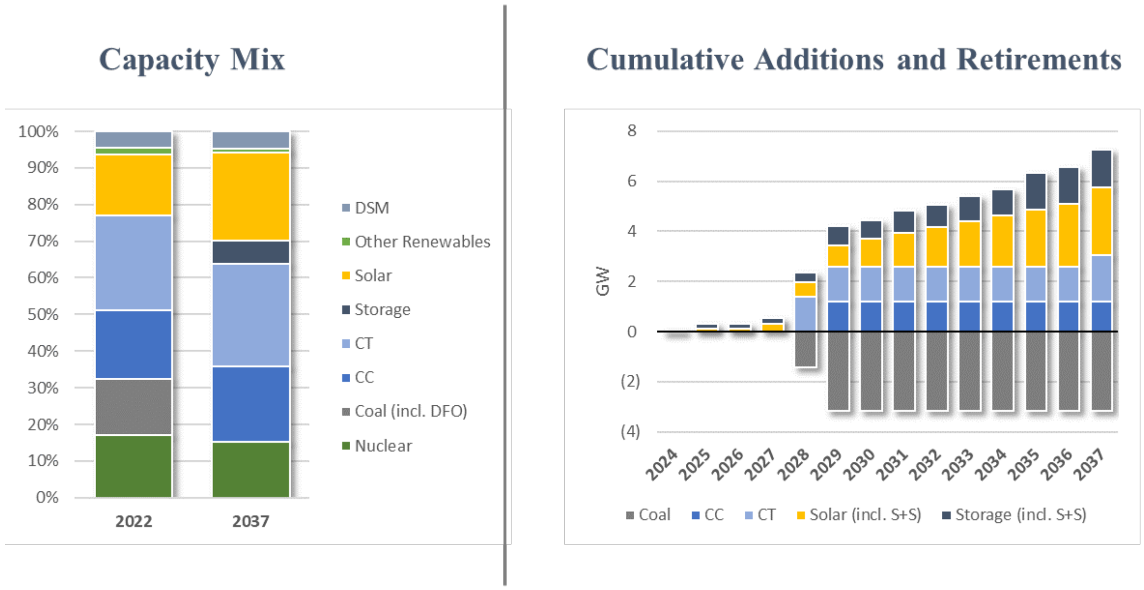


Figure 6-E illustrates both the current and forecasted capacity by fuel type for the DEP system, as developed in Portfolio A2 in more granular detail.

Figure 6-E: DEP 2023 & 2037 Portfolio A2 Winter Capacity Mix [8]

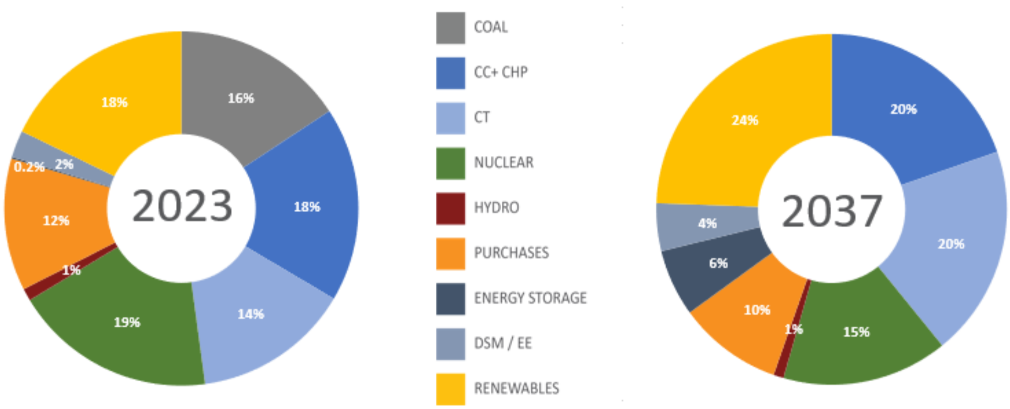


Figure 6-F below represents the incremental resources added in DEP from 2023 to 2037 in Portfolio A2.

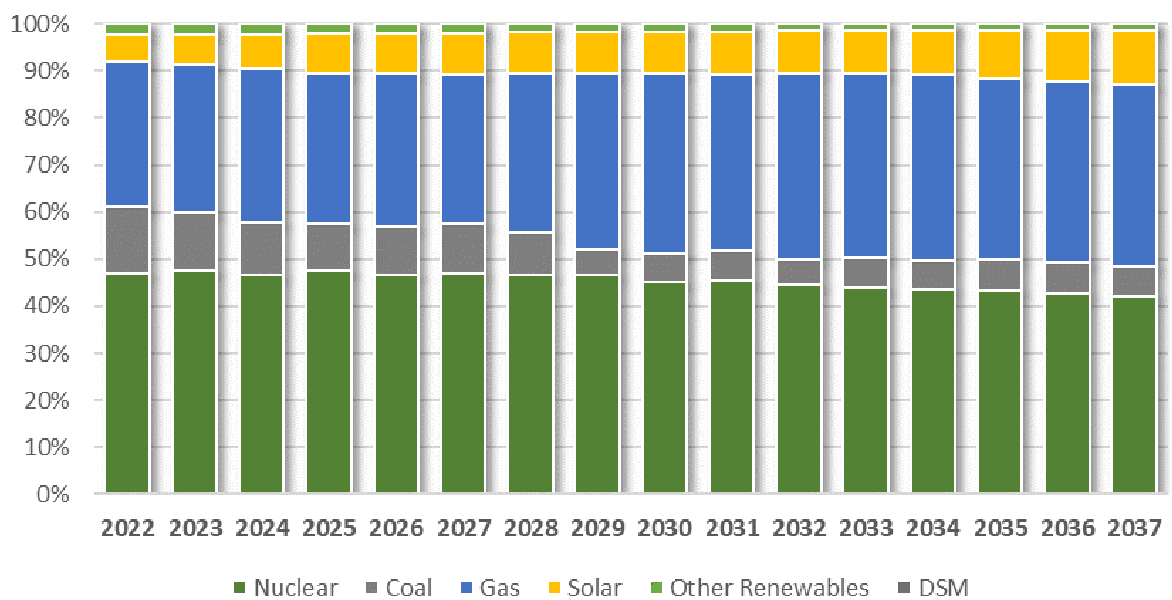
Figure 6-F: DEP Capacity Resources added from 2023 to 2037 in Portfolio A2 (Winter)

Resource Type:	% Added:
Energy Storage (Pumped + Battery)	20%
CC + CHP	16%
Renewables	32%
CT	25%
DSM/EE	8%

[8] EE represents incremental EE and does not reflect impacts of historical efforts. All capacity represents reliable capacity at time of peak with the exception of renewable resources, which represent nameplate capacity.

Figure 6-G represents the energy of both the DEP and DEC Portfolio A2 over time. Due to the joint dispatch agreement ("JDA") in place between the Companies, it is prudent to combine the energy of both utilities to develop a meaningful energy figure. From 2023 to 2037, the figure shows that nuclear resources will continue to serve almost half of the energy needs for DEP and DEC. Additionally, Portfolio A2 shows a reduction in the energy served by coal and an increase in the energy served by natural gas, renewables and EE.

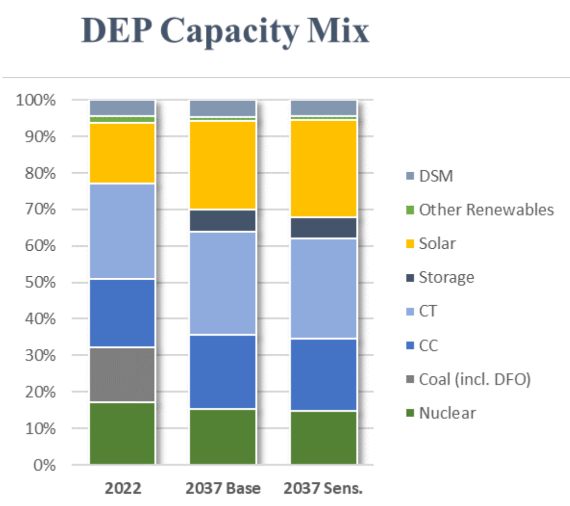
Figure 6-G: Combined DEP and DEC Energy Mix Over Time– Portfolio A2 Update

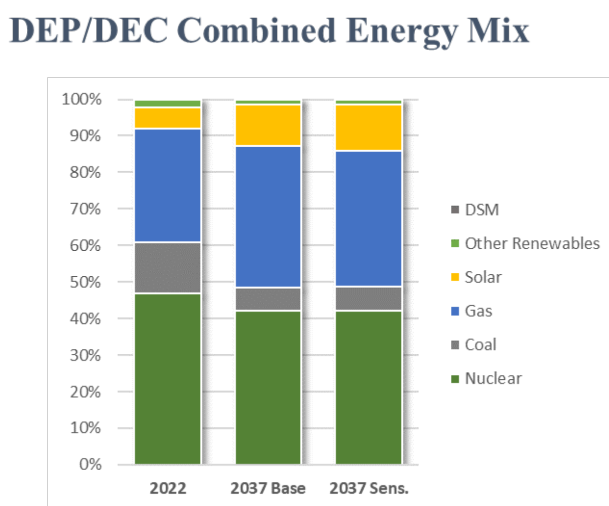


Solar PPA Sensitivity

As described in Chapter 5 – Renewable Energy and Energy Storage Resources, and as directed by the Commission, the Company included a sensitivity analysis in this 2022 SC IRP Update to explore potential changes to the resource portfolio and associated PVRR under the assumption that the $38/MWh solar PPA resource option could comprise up to 100% of new model-selected solar resources. Changing this assumption to increase the portion of new solar that could be comprised of $38/MWh PPAs resulted in the selection of approximately 0.8 GW of additional PPA solar above the amount selected in the base case Portfolio A2 update by 2037 in DEP. No other resource types were affected. Figure 6-H below shows a comparison of the capacity and energy mixes for the base case and the sensitivity case.

Figure 6-H: Portfolio A2 Update Base Case and PPA Sensitivity Capacity and Energy Mixes





As illustrated in Figure 6-H above, the additional solar and storage did not displace any new gas generation in the PPA sensitivity case. The model still selected one new CC unit and 1.8 GW of new CT capacity. Increasing the selectable amount of $38/MWh energy from these PPAs slightly reduced the portion of total DEP/DEC energy supplied by gas resources (a difference of approximately 1.6 percentage points in 2037 from the base case to the sensitivity), but total portfolio PVRR was unchanged at $27.1 billion for DEP. As explained in Chapter 5 – Renewable Energy and Energy Storage Resources, the $38/MWh price is unlikely to be achievable for a 20-year solar PPA.

DEP-OWNED GENERATION

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

Tables 7-A through 7-K below list the Duke Energy Progress' plants in service in South Carolina and North Carolina with plant statistics, planned uprates, projected retirement dates, estimated remaining life, relicensing status and the system's total generating capability. All generating unit ratings are as of January 1, 2022.

Table 7-A: DEP Coal – Existing Generating Units and Ratings

Coal									
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
Mayo	1	713	704	Roxboro, NC	Coal	Intermediate	39	6	N/A
Roxboro	1	380	379	Semora, NC	Coal	Intermediate	56	6	N/A
Roxboro	2	673	668	Semora, NC	Coal	Intermediate	54	6	N/A
Roxboro	3	698	694	Semora, NC	Coal	Intermediate	49	5	N/A
Roxboro	4	711	698	Semora, NC	Coal	Intermediate	42	5	N/A
Total DEP Coal		3,175	3,143						

Note: Resource type based on NERC capacity factor classifications which may vary over the forecast period.

Table 7-B: DEP Combustion Turbines – Existing Generating Units and Ratings

Combustion Turbines									
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
Asheville	3	185	160	Arden, NC	Natural Gas/Oil	Peaking	23	17	N/A
Asheville	4	185	160	Arden, NC	Natural Gas/Oil	Peaking	23	17	N/A
Blewett	1	17	13	Lilesville, NC	Oil	Peaking	51	17	N/A
Blewett	2	17	13	Lilesville, NC	Oil	Peaking	51	17	N/A
Blewett	3	17	13	Lilesville, NC	Oil	Peaking	51	17	N/A
Blewett	4	17	13	Lilesville, NC	Oil	Peaking	51	17	N/A
Darlington	12	131	118	Hartsville, SC	Natural Gas/Oil	Peaking	48	17	N/A
Darlington	13	133	116	Hartsville, SC	Natural Gas/Oil	Peaking	48	17	N/A
Smith	1	192	157	Hamlet, NC	Natural Gas/Oil	Peaking	21	19	N/A
Smith	2	192	156	Hamlet, NC	Natural Gas/Oil	Peaking	21	19	N/A
Smith	3	192	155	Hamlet, NC	Natural Gas/Oil	Peaking	21	19	N/A
Smith	4	192	159	Hamlet, NC	Natural Gas/Oil	Peaking	21	19	N/A
Smith	6	192	145	Hamlet, NC	Natural Gas/Oil	Peaking	21	19	N/A
Sutton	4	49	42	Wilmington, NC	Natural Gas/Oil	Peaking	5	35	N/A
Sutton	5	48	42	Wilmington, NC	Natural Gas/Oil	Peaking	5	35	N/A
Wayne	1/10	195	169	Goldsboro, NC	Oil/Natural Gas	Peaking	22	18	N/A
Wayne	2/11	195	174	Goldsboro, NC	Oil/Natural Gas	Peaking	22	18	N/A
Wayne	3/12	195	164	Goldsboro, NC	Oil/Natural Gas	Peaking	22	18	N/A
Wayne	4/13	195	162	Goldsboro, NC	Oil/Natural Gas	Peaking	22	18	N/A
Wayne	5/14	195	153	Goldsboro, NC	Oil/Natural Gas	Peaking	22	27	N/A
Weatherspoon	1	41	31	Lumberton, NC	Natural Gas/Oil	Peaking	52	17	N/A
Weatherspoon	2	41	31	Lumberton, NC	Natural Gas/Oil	Peaking	52	17	N/A
Weatherspoon	3	41	32	Lumberton, NC	Natural Gas/Oil	Peaking	52	17	N/A

Combustion Turbines									
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
Weatherspoon	4	41	30	Lumberton, NC	Natural Gas/Oil	Peaking	52	17	N/A
Total DEP CT		2,898	2,408						

Note: Resource type based on NERC capacity factor classifications which may vary over the forecast period.

Table 7-C: DEP Combined Cycle – Existing Generating Units and Ratings

Combined Cycle									
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
Asheville	CT5	190	153	Arden, NC	Natural Gas/Oil	Base	3	37	N/A
Asheville	ST6	90	85	Arden, NC	Natural Gas/Oil	Base	3	37	N/A
Asheville	CT7	190	153	Arden, NC	Natural Gas/Oil	Base	2	37	N/A
Asheville	ST8	90	85	Arden, NC	Natural Gas/Oil	Base	2	37	N/A
Asheville CTCC		560	476						
Lee	CT1A	225	170	Goldsboro, NC	Natural Gas/Oil	Base	10	26	N/A
Lee	CT1B	225	170	Goldsboro, NC	Natural Gas/Oil	Base	10	26	N/A
Lee	CT1C	225	170	Goldsboro, NC	Natural Gas/Oil	Base	10	26	N/A
Lee	ST1	379	378	Goldsboro, NC	Natural Gas/Oil	Base	10	26	N/A
Lee CTCC		1054	888						
Smith	CT7	193	152	Hamlet, NC	Natural Gas/Oil	Base	20	20	N/A
Smith	CT8	193	152	Hamlet, NC	Natural Gas/Oil	Base	20	20	N/A
Smith	ST4	184	171	Hamlet, NC	Natural Gas/Oil	Base	20	20	N/A
Smith PB4 CTCC		570	475						
Smith	CT9	215	178	Hamlet, NC	Natural Gas/Oil	Base	11	25	N/A

Combined Cycle									
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
Smith	CT10	215	178	Hamlet, NC	Natural Gas/Oil	Base	11	25	N/A
Smith	ST5	250	252	Hamlet, NC	Natural Gas/Oil	Base	11	25	N/A
Smith PB5 CTCC		680	608						
Sutton	CT1A	224	170	Wilmington, NC	Natural Gas/Oil	Base	9	27	N/A
Sutton	CT1B	224	171	Wilmington, NC	Natural Gas/Oil	Base	9	27	N/A
Sutton	ST1	271	266	Wilmington, NC	Natural Gas/Oil	Base	9	27	N/A
Sutton CTCC		719	607						
Total DEP CTCC		3,583	3,054						

Note: Resource type based on NERC capacity factor classifications which may vary over the forecast period.

Table 7-D: DEP Hydro – Existing Generating Units and Ratings

Hydro									
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
Blewett	1	4	4	Lilesville, NC	Water	Intermediate	110	33	2055
Blewett	2	4	4	Lilesville, NC	Water	Intermediate	110	33	2055
Blewett	3	4	4	Lilesville, NC	Water	Intermediate	110	33	2055
Blewett	4	5	5	Lilesville, NC	Water	Intermediate	110	33	2055
Blewett	5	5	5	Lilesville, NC	Water	Intermediate	110	33	2055
Blewett	6	5	5	Lilesville, NC	Water	Intermediate	110	33	2055
Marshall	1	2	2	Marshall, NC	Water	Intermediate	112	N/A	Exempt
Marshall	2	2	2	Marshall, NC	Water	Intermediate	112	N/A	Exempt
Tillery	1	21	21	Mt. Gilead, NC	Water	Intermediate	97	33	2055
Tillery	2	18	18	Mt. Gilead, NC	Water	Intermediate	97	33	2055
Tillery	3	21	21	Mt. Gilead, NC	Water	Intermediate	97	33	2055
Tillery	4	25	25	Mt. Gilead, NC	Water	Intermediate	97	33	2055
Walters	1	36	36	Waterville, NC	Water	Intermediate	92	12	2034
Walters	2	40	40	Waterville, NC	Water	Intermediate	92	12	2034
Walters	3	36	36	Waterville, NC	Water	Intermediate	92	12	2034
Total DEP Hydro		228	228						

Table 7-E: DEP Solar – Existing Generating Units and Ratings

Solar								
	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
NC Solar	155	155	NC	Solar	Intermittent	Various	N/A	N/A
Total DEP Solar	155	155						

Note: Solar capacity ratings reflect nameplate capacity.

Table 7-F: DEP Energy Storage – Existing Generating Units and Ratings

Energy Storage								
	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
Asheville-Rock Hill	8.8	8.8	Asheville, NC	Energy Storage	Intermittent	2	N/A	N/A
Energy Storage Total	8.8	8.8						

Note: Resource type based on NERC capacity factor classifications which may vary over the forecast period.

Table 7-G: DEP Nuclear – Existing Generating Units and Ratings

Nuclear									
	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type	Age (Years)	Estimated Remaining Life	Relicensing Status
Brunswick	1	975	938	Southport, NC	Nuclear	Base	45	14	2036
Brunswick	2	953	932	Southport, NC	Nuclear	Base	47	12	2034
Harris	1	1009	964	New Hill, NC	Nuclear	Base	36	24	2046
Robinson	2	793	759	Hartsville, SC	Nuclear	Base	52	8	2030
Total DEP Nuclear		3,730	3,593						

Table 7-H: DEP Total Generation Capability

Total Generation Capability		
	Winter Capacity (MW)	Summer Capacity (MW)
Total DEP System - N.C.	12,721	11,597
Total DEP System - S.C.	1,057	993
Total DEP System	13,778	12,590

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

Note: Solar capacity ratings reflect nameplate winter and summer peak values.

Table 7-I: Unit Retirements

Unit Retirements					
Unit Name	Location	Capacity (MW) Winter / Summer		Fuel Type	Retirement Date
Asheville	Arden, NC	158	155	Coal	1/29/20
Asheville	Arden, NC	192	189	Coal	1/29/20
Cape Fear 5	Moncure, NC	148	144	Coal	10/1/12
Cape Fear 6	Moncure, NC	175	172	Coal	10/1/12
Cape Fear 1A	Moncure, NC	14	11	Oil	3/31/13
Cape Fear 1B	Moncure, NC	14	12	Oil	3/31/13
Cape Fear 2A	Moncure, NC	15	12	Oil	3/31/13
Cape Fear 2B	Moncure, NC	14	11	Oil	10/1/12
Cape Fear 1	Moncure, NC	12	11	Steam Turbine	3/31/11
Cape Fear 2	Moncure, NC	12	7	Steam Turbine	3/31/11
Darlington 1	Hartsville, SC	63	50	Natural Gas/Oil	3/20
Darlington 2	Hartsville, SC	64	48	Oil	3/31/20
Darlington 3	Hartsville, SC	63	50	Natural Gas/Oil	3/31/20
Darlington 4	Hartsville, SC	66	48	Oil	3/31/20
Darlington 5	Hartsville, SC	66	51	Natural Gas/Oil	5/31/18
Darlington 6	Hartsville, SC	62	43	Oil	3/31/20
Darlington 7	Hartsville, SC	65	47	Natural Gas/Oil	3/31/20
Darlington 8	Hartsville, SC	66	44	Oil	3/31/20
Darlington 9	Hartsville, SC	65	50	Oil	6/30/17
Darlington 10	Hartsville, SC	65	49	Oil	3/31/20
Darlington 11	Hartsville, SC	67	52	Natural Gas/Oil	11/8/15
Lee 1	Goldsboro, NC	80	74	Coal	9/15/12
Lee 2	Goldsboro, NC	80	68	Coal	9/15/12

Unit Retirements					
Unit Name	**Location**	**Capacity (MW) Winter / Summer**		**Fuel Type**	**Retirement Date**
Lee 3	Goldsboro, NC	252	240	Coal	9/15/12
Lee 1	Goldsboro, NC	15	12	Oil	10/1/12
Lee 2	Goldsboro, NC	27	21	Oil	10/1/12
Lee 3	Goldsboro, NC	27	21	Oil	10/1/12
Lee 4	Goldsboro, NC	27	21	Oil	10/1/12
Morehead 1	Morehead City, NC	15	12	Oil	10/1/12
Robinson 1	Hartsville, SC	179	177	Coal	10/1/12
Robinson 1	Hartsville, SC	15	11	Natural Gas/Oil	3/31/13
Weatherspoon 1	Lumberton, NC	49	48	Coal	9/30/11
Weatherspoon 2	Lumberton, NC	49	48	Coal	9/30/11
Weatherspoon 3	Lumberton, NC	79	74	Coal	9/30/11
Sutton 1	Wilmington, NC	98	97	Coal	11/27/13
Sutton 2	Wilmington, NC	95	90	Coal	11/27/13
Sutton 3	Wilmington, NC	389	366	Coal	11/4/13
Sutton GT1	Wilmington, NC	12	11	Oil/Natural Gas	3/1/17
Sutton GTA	Wilmington, NC	31	23	Oil/Natural Gas	7/8/17
Sutton GTB	Wilmington, NC	33	25	Oil/Natural Gas	7/8/17
Total DEP Retirements		3,018	2,695		

Table 7-J: DEP Planning Unit Retirements

Planning Unit Retirements					
Unit & Plant Name	Winter Capacity (MW)	Summer Capacity (MW)	Location	Fuel Type	Expected Retirement
Mayo 1	746	727	Roxboro, NC	Coal	12/2028
Roxboro 1	380	379	Semora, NC	Coal	12/2028
Roxboro 2	673	665	Semora, NC	Coal	12/2028
Roxboro 3	698	691	Semora, NC	Coal	12/2027
Roxboro 4	711	698	Semora, NC	Coal	12/2027
Total DEP	3,028	3,160			

Note: Retirement assumptions are for planning purposes only; retirement dates determined in analysis.

Note: Coal retirement dates represent the most economic retirement dates as developed in the 2020 IRP and utilized in the 2020 SC Modified IRP.

Note: All retirement dates assume retirement at the end of year represented.

Note: For planning purposes, the 2022 SC IRP Update assumes subsequent license renewal for existing nuclear facilities beginning at end of current licenses. Total planning retirements exclude nuclear capacities.

Table 7-K: Operating License Renewal

Operating License Renewal - Nuclear				
Plant and Unit Name	Location	Original Operating License Expiration	Date of Approval	Extended Operating License Expiration
Robinson 2	Hartsville, SC	07/31/2010	04/19/2004	07/31/2030
Brunswick 2	Southport, NC	12/27/2014	06/26/2006	12/27/2034
Brunswick 1	Southport, NC	09/08/2016	06/26/2006	09/08/2036
Harris #1	New Hill, NC	10/24/2026	12/17/2008	10/24/2046

Note: For planning purposes, the 2022 SC IRP Update assumes subsequent license renewal for existing nuclear facilities beginning at end of current licenses. Total planning retirements exclude nuclear capacities.

WHOLESALE CONTRACTS

The following tables describe the wholesale sales and purchase contracts for Duke Energy Progress ("DEP").

Wholesale Sales Contracts

Aggregated Table 8-A below includes wholesale sales contracts that are included in the Fall 2021 Load Forecast.

Wholesale Purchase Contracts

Aggregated Table 8-B below includes all wholesale purchase contracts that are included as resources in the DEP 2022 SC IRP Update.

Table 8-A: DEP Wholesale Sales Contracts

DEP Aggregated Wholesale Sales Contracts Commitment (MW)									
2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
4,407	4,222	4,196	3,955	3,954	4,032	4,063	4,087	4,100	4,147

Note: For wholesale contracts, Duke Energy Progress assumes all whole sales contracts will renew unless there is an indication that the contract will not be renewed.

Note: 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.).

Note: Table represents winter capacity.

Table 8-B: DEP Aggregated Firm Wholesale Purchase Power Contracts

Purchased Power Contract	Winter Capacity (MW)	Location	Volume of Purchases (MWh) Jan '21-Dec '21
Gas/Peaking	850	SC	331,734
Gas/Peaking	1173	NC	597,233
Gas/Intermediate	415	NC	1,643,835

Note: Data represented above represents contractual agreements. These resources may be modeled differently in the IRP.

FUEL COMMODITY PRICES

Natural Gas

The natural gas price forecast used for this 2022 SC IRP Update incorporates both a short-term, market-based price forecast and longer-term, fundamentals-based price forecasts, as well as a transition period from market-based pricing to fundamentals-based pricing. Specifically, the natural gas price forecast consists of eighteen months of market-based pricing (2023 to mid-2024), an eighteen-month transition from market to fundamentals-based pricing (mid-2024 to 2025), and fundamentals-based pricing for the remainder of the study period (2026-2037).

In addition to short-term market price volatility, longer-term natural gas price forecasts have also varied among fundamentals providers and can be significantly impacted by the assumptions made in each provider's forecast and the time at which each forecast is issued especially when some forecasts are only produced once or twice per year. To limit reliance on any single fundamentals-based forecast, for this 2022 SC IRP Update the Company used an average of the following four recent natural gas price forecasts:

- Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO") Reference Case (2021 AEO)
- Wood Mackenzie North American Power Markets (Base Case) (2021)
- EVA FuelCast (2021)
- IHS Markit Long-Term Natural Gas Outlook (August 2021)

Coal

Coal market volatility has increased in recent years for a variety of reasons, all of which increase risks to coal supply assurance in the Carolinas. There have been significant coal generation retirements across the nation as power generators transition their fleets to lower carbon energy sources, such as renewables and natural gas. Additional planned retirements for the nation's aging coal facilities contribute to the continuing deterioration of the domestic coal supply chain. Customer fuel cost and fuel unavailability risks increase as coal production continues to decrease. The decline in supply flexibility and increase in market uncertainty create future risks for coal supply assurance and ultimately create risks for customers. While the Company continues to focus on coal supply assurance, these affordability and reliability risks support retiring coal facilities and developing new advanced generation dispatch methodologies to manage the energy transition. Full consideration of these evolving risks is beyond the limited purpose of IRP updates, and the Company looks forward to addressing these issues more completely in its next comprehensive IRP filing.

The coal price forecast used for this IRP Update consists of eighteen months of market-based pricing (2023 to mid-2024), an eighteen-month transition from market to fundamentals-based pricing (mid-2024 to 2025), and fundamentals-based pricing for the remainder of the study period (2026-2037). The fundamentals-based price forecast is an average of recent forecasts from the same four providers used for the natural gas price forecast.

Table 9-A below provides the fuel commodity prices used in the DEP 2022 SC IRP Update for natural gas, coal, and fuel oil.

Table 9-A: DEP Annual Average Fuel Prices ($/MMBtu)

Year	Natural Gas Henry Hub	Coal DEP Average	Fuel Oil Average
2023	$6.08	$6.31	$24.98
2024	$4.97	$5.10	$21.10
2025	$3.83	$4.28	$21.73
2026	$3.31	$3.34	$22.38
2027	$3.44	$3.34	$23.05
2028	$3.58	$3.41	$23.75
2029	$3.70	$3.51	$24.46
2030	$3.82	$3.57	$25.19
2031	$3.94	$3.60	$25.95
2032	$4.07	$3.65	$26.73
2033	$4.22	$3.69	$27.53
2034	$4.31	$3.76	$28.35
2035	$4.46	$3.85	$29.21
2036	$4.61	$3.93	$30.08
2037	$4.74	$4.03	$30.98

CROSS REFERENCE – ACT 62 REQUIREMENTS AND COMMISSION ORDER NOS. 2021-447 AND 2022-332

Requirement	Source	Location
An electrical utility and the Public Service Authority shall each submit annual updates to its integrated resource plan to the commission. An annual update must include an update to the electric utility's or the Public Service Authority’s base planning assumptions relative to its most recently accepted integrated resource plan, including, but not limited to: energy and demand forecast, commodity fuel price inputs, renewable energy forecast, energy efficiency and demand-side management forecasts, changes to projected retirement dates of existing units, along with other inputs the commission deems to be for the public interest.	§ 58-37-40(D)(1)	Ch. 2- Updates to Base Planning Assumptions (overview of updates to base planning assumptions) Ch. 3 – Electric Load Forecast (energy & demand forecast) Ch. 4 – Energy Efficiency, Demand Side Management and Voltage Optimization (EE/DSM forecast) Ch. 5 – Renewable Energy and Energy Storage Resources (renewable energy forecast) Ch. 7 – DEC-Owned Generation (unit retirement dates) Ch. 8 – Wholesale Contracts (wholesale

Requirement	Source	Location
		purchases/sales) Ch. 9 – Fuel Commodity Prices (fuel price inputs)
The electrical utility's or Public Service Authority's annual update must describe the impact of the updated base planning assumptions on the selected resource plan.	§ 58-37-40(D)(1)	Ch. 2 – Updates to Base Planning Assumptions
Duke is required to use the UCT when developing EE/DSM scenarios and savings projections in its future IRPs, IRP updates, and market potential studies.	Order No. 2021-447 Ordering Paragraph 2 Finding of Fact Nos. 2-4	Ch. 4 – Energy Efficiency, Demand Side Management and Voltage Optimization
In future IRPs, IRP updates and market potential studies, Duke must work with the EE/DSM Collaborative to identify a set of reasonable assumptions surrounding 1) increased market acceptance of existing technologies and 2) emerging technologies to incorporate into EE/DSM saving forecasts.	Order No. 2021-447 Ordering Paragraph 3 Finding of Fact Nos. 2-4	Ch. 4 – Energy Efficiency, Demand Side Management and Voltage Optimization
Duke should make a number of changes to its development of effective load carrying capability ("ELCC") values and revisions to its capacity expansion modeling that incorporates those ELCC values, including: (a) Applying single step-optimization rather than multi-step optimization when conducting its capacity expansion modeling; (b) Creating an ELCC "surface" that determines the combined capacity value of different portfolios of solar and storage; (c) Revising ELCC studies by: (i) Varying ELCC as a function of load, including applying a 2035 load profile; (ii) Modeling all future solar as single-axis tracking consistent with industry trends; and (iii) Updating DR values to include those identified in the Winter Peak Demand Reduction Potential Assessment.	Order No. 2021-447 Ordering Paragraph 6 Finding of Fact Nos. 6-10	Ch. 6 – Development of Resource Plan Attachment I Updated 2022 ELCC Study
In its Modified IRP, IRP Update, and future full IRPs, Duke shall remodel its portfolios using natural gas pricing forecasts that rely on market prices for eighteen months before transitioning over eighteen	Order No. 2021-447 Ordering Paragraph 10 Finding of Fact Nos.	Ch. 9 – Fuel Commodity Prices

Requirement	Source	Location
months to the average of at least two fundamentals-based forecasts, as recommended by CCEBA Witness Lucas.	12-14	
In the Modified IRP and IRP Update, Duke shall include third-party solar PPAs priced at $38/MWh as a selectable resource. Any change to this pricing in subsequent IRPs or IRP Updates shall be supported by a reasonable investigation into market conditions in Duke's service territories. For purposes of modeling solar PPAs as a selectable resource, the Company shall assume a contract term of at least 20 years, and operational characteristics identical to CPRE projects.	Order No. 2021-447 Ordering Paragraph 11-12 Finding of Fact Nos. 15-17	Ch. 5 – Renewable Energy and Energy Storage Resources
In its Modified IRP and future IRPs, Duke shall use the NREL ATB Low figures for battery storage costs	Order No. 2021-447 Ordering Paragraph 16 Finding of Fact No. 20	Ch. 5 – Renewable Energy and Energy Storage Resources
In its Modified IRP and next IRP Update, Duke shall assume a 750 MW annual limitation on the interconnection of solar and storage resources.	Order No. 2021-447 Ordering Paragraph 17 Finding of Fact Nos. 21-23	Ch. 5 – Renewable Energy and Energy Storage Resources
In future IRPs, including Modified IRPs and IRP Updates, Duke shall perform and include a minimax regret analysis of the type described and performed in this proceeding by CCEBA Witness Lucas.[1]	Order No. 2021-447 Ordering Paragraph 19 Finding of Fact No. 24	N/A (DEC's 2022 SC IRP Update models updated base planning assumptions for Portfolio A2. No other portfolios were developed for comparison purposes required to perform a minimax regret analysis. Such analysis will be conducted in the 2023 IRP.)
In all future IRPs and IRP Updates, Duke shall	Order No. 2021-447	Ch. 5 – Renewable

[1] In Order No. 2021-509, the Commission clarified that the Companies were to perform the minimax regret analysis recommended and described by ORS Witness Kollen.

Requirement	Source	Location
include a solar purchase power resource option as a sensitivity.	Ordering Paragraph 20	Energy and Energy Storage Resources
Recommend the Companies provide additional justification for its Battery Energy Storage fixed O&M cost and capacity factor assumptions.	Order No. 2021-447 Ordering Paragraph 22	Ch. 5 – Renewable Energy and Energy Storage Resources
Duke Energy Progress, LLC and Duke Energy Carolinas, LLC shall include the following modeling or scenarios to be evaluated and examined as part of the next IRP filing, whether an update or comprehensive plan: pricing and support per Order No. 2021-447, third-party solar PPAs as a selectable option for (a) fifty percent (50%) or half of the 750 MW renewable interconnection limit per year; and (b) one hundred percent (100%) of the 750 MW renewable interconnection limit per year.	Order No. 2022-332 Ordering Paragraph 2	Ch. 5 – Renewable Energy and Energy Storage Resources

GLOSSARY OF TERMS

AC or A/C	Alternating Current
ACT 62	South Carolina Energy Freedom Act of 2019
AEO	Annual Energy Outlook
AR	Advanced Reactor
ATB	Annual Technology Baseline
BOEM	Bureau of Ocean Energy Management
BTM	Behind-the-meter
BYOT	Bring Your Own Thermostat
CC	Combined Cycle
CHP	Combined Heat and Power
CIG	Commercial, Industrial and Governance
COD	Commercial Operation Date
COMMISSION	Public Service Commission of South Carolina
CPP	Critical Peak Pricing
CPRE	Competitive Procurement of Renewable Energy
CT	Combustion Turbine
CVR	Conservation Voltage Reduction
DEC	Duke Energy Carolinas, LLC
DEP	Duke Energy Progress, LLC
DMS	Distribution Management System
DOE	Department of Energy
DR	Demand Response
DSM	Demand-Side Management
EE	Energy Efficiency
EEE	Energy Efficiency Engineers
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
EV	Electric Vehicles

GLOSSARY OF TERMS

GW	Gigawatt
GWh	Gigawatt-hour
HRSG	Heat Recovery Steam Generator
IPI	Industrial Production Index
IRP	Integrated Resource Plan
IS	Interruptible Service
ITC	Federal Investment Tax Credit
IVVC	Integrated Volt-Var Control
JDA	Joint Dispatch Agreement
kW	Kilowatt
kW-AC	Kilowatts-alternating current
kWh	Kilowatt-hour
LCR Table	Load, Capacity and Reserves Table
Li-ION	Lithium Ion
LOLE	Loss of Load Expectation
M&V	Measurement and Verification
MISO	Midcontinent Independent Operator
MPS	Market Potential Study
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-hour
NC	North Carolina
NC HB 589	North Carolina House Bill 589
NC HB 951	North Carolina House Bill 951
NC REPS or REPS	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
NCEMC	North Carolina Electric Membership Corporation
NCUC	North Carolina Utilities Commission
NEM	Net Energy Metering
NREL	National Renewable Energy Laboratory
O&M	Operating and Maintenance
PPA	Purchase Power Agreement
PSCSC	Public Service Commission of South Carolina
PSH	Pumped Storage Hydro
PTC	Production Tax Credit
PV	Photovoltaic
PVRR	Present Value Revenue Requirement
QF	Qualifying Facility
REC	Renewable Energy Certificate

GLOSSARY OF TERMS

REPS or NC REPS	Renewable Energy and Energy Efficiency Portfolio Standard
RFP	Request for Proposal
RIM	Rate Impact Measure
SAE	Statistical Adjusted End-Use Model
SAT Solar	Single-Axis Tracking Solar
SC	South Carolina
SG	Standby Generation or Standby Generator Control
SLR	Subsequent License Renewal
SMR	Small Modular Reactor
SPS	Solar Paired With Storage
TE	Transportation Electrification
The Company	Duke Energy Progress
TOU	Time-of-Use
TRC	Total Resource Cost
UCT	Utility Cost Test
UEE	Utility Energy Efficiency
VAR	Volt Ampere Reactive
VAST	Vehicle Analytics and Simulation Tool
VVO	Volt-Var Optimization