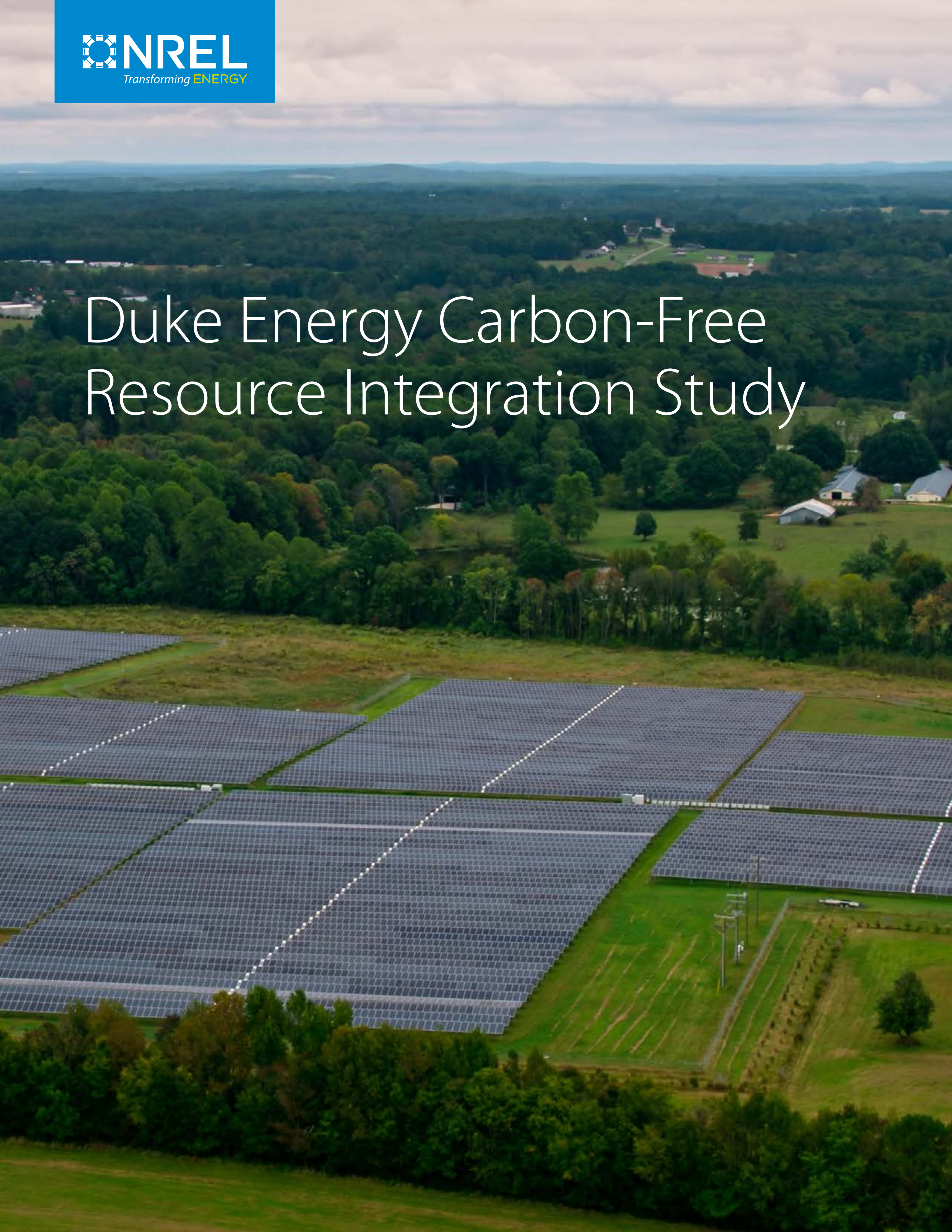
Duke Energy Carbon-Free Resource Integration Study



Duke Energy Carbon-Free Resource Integration Study

Brian Sergi, Greg Brinkman, Michael Emmanuel,
Omar J. Guerra, Dan Steinberg, and Bri-Mathias Hodge

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ACKNOWLEDGMENTS

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List of Acronyms

AEO	*Annual Energy Outlook*
ATB	Annual Technology Baseline
BCF	billion cubic feet
CO_2	carbon dioxide
EIA	U.S. Energy Information Administration
Gas-CC	gas combined cycle
Gas-CT	gas combustion turbine
IRP	Integrated Resource Plan
LCOE	levelized cost of energy
MMT	million metric tons
MWh	megawatt-hour
NEMS	National Energy Modeling System
NEXRAD	Next-Generation Weather Radar
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
PV	photovoltaic(s)
RE-CT	renewable energy combustion turbine
ReEDS	Regional Energy Deployment System
reV	Renewable Energy Potential
SAM	System Advisor Model
VRE	variable renewable energy
WIND Toolkit	Wind Integration National Dataset Toolkit

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Executive Summary

In 2019, Duke Energy committed to reducing carbon dioxide (CO_2) emissions on its electricity system by 50% from 2005 levels by 2030 and to moving toward net-zero carbon emissions from the electric sector by 2050 (Duke Energy 2020a). Along these lines, in October 2021, North Carolina passed House Bill 951: *Energy Solutions for North Carolina*, which commits the state to a 70% carbon emissions reduction by 2030, along with achieving carbon neutrality in 2050.

Given these targets, Duke Energy is committed to evaluating the costs, challenges, and benefits of integrating higher levels of carbon-free electricity generation into their Carolinas system. To that end, Duke Energy has partnered with the National Renewable Energy Laboratory (NREL) to explore the pathways for achieving their carbon-free targets and to assess the operational characteristics of the resulting system.

The Duke Energy Carbon-Free Resource Integration study included two phases. In Phase 1, NREL and Duke Energy conducted a net load analysis evaluating the operational impacts of higher solar photovoltaic (PV) shares in the Carolinas (Matsuda-Dunn et al. 2020). This report details findings from Phase 2 of the study, which consisted of three distinct but interrelated analyses:

1. **Resource assessment**: determination of the technical and economic potential and characteristics of wind and solar PV resources in the Carolinas
2. **Capacity expansion modeling**: identification and analysis of least-cost investment pathways to achieving 70% CO_2 emissions reductions in North Carolina by 2030, along with a net-zero electricity system by 2050
3. **Operational modeling**: detailed production cost modeling of power system operations at the higher shares of low- and zero-carbon generation resources, informed by the capacity expansion modeling portion of the analysis.

The resource assessment portion of the study used NREL's Renewable Energy Potential (reV) model (Maclaurin et al. 2019) to identify the technical and economic potential for wind and solar PV power sources in the Carolinas. The model draws on detailed historical weather data to determine the available wind and solar PV generation resources. It also incorporates spatial layers related to land use, ownership, and other characteristics to exclude areas that could be challenging or unavailable for renewable generation development.

Data from the resource assessment were then used to inform a capacity expansion planning process that evaluated the least-cost mix of generation resources to meet Duke Energy's policy targets while satisfying planning, operational, and policy constraints. For the capacity expansion modeling, NREL employed its Regional Energy Deployment Systems (ReEDS™) model (Brown et al. 2020) to explore the evolution of the power system through 2050 across three core scenarios: a reference case with no additional policy, a policy case that enforces 2030 and 2050 emissions targets in North Carolina, and a policy case in which all fossil-fueled generation in the Carolinas must retire by 2050. In addition, NREL evaluated a range of sensitivities across cost projections, technological developments, and other scenarios to explore how the investment pathways change across different conditions.

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Although capacity expansion models are effective tools for guiding future investments, they do not represent or address all economic, physical, social, or environmental drivers of power system evolution or investment pathways, and as such they should always be considered along with broader information and analyses—both quantitative and qualitative—of a utility's or a region's power system. Further, computational limits typically restrict the capacity expansion model's ability to capture detailed operational behavior. To refine our understanding of the potential challenges of operating these future low- and zero-carbon systems, we select and evaluate a subset of the ReEDS-identified buildouts within a production cost model, specifically Energy Exemplar's PLEXOS model (Energy Exemplar 2022).

We test two classes of models in PLEXOS: (1) a nodal model with full nodal transmission representation in the Carolinas and (2) a zonal model that mirrors the zonal transmission representation in ReEDS. The nodal model focuses primarily on the 2030 policy target and includes sensitivities testing a 2030 system with accelerated coal retirements and a 2036 buildout modeled with weather and load data from a year with an extended cold period in the winter. The zonal model analysis focuses on the net-zero electricity system in 2050.

The following paragraphs summarize the key findings of the study. These findings provide insight into the types of investments needed to support a decarbonized system as well as the operations and dynamics of such a system. These findings are directionally consistent with previous assessments of decarbonization pathways in the Carolinas, although specific outcomes might differ depending on modeling assumptions. For example, this analysis focuses on the capacity mix that can achieve the decarbonization targets, but it does not evaluate how the timing of new capacity builds might be impacted by supply chain or workforce constraints, construction logistics, or the need to perform more detailed transmission planning studies. Note also that we do not model contingency events—although we do model holding contingency reserves—nor do we evaluate buildouts for transient stability. Future analyses should consider these aspects.

Also, the NREL study was initiated before more recent commitments to accelerate the retirement of some units of Duke Energy's existing coal fleet, and thus it might reflect different pathways in terms of the deployment of coal and natural gas toward meeting the 2030 target than Duke Energy's forthcoming Carbon Plan. Other modeling assumptions—such as the consideration of dynamic or transient stability, contingency analysis, nodal transmission expansion, or gas pipeline constraints—can also affect the amount or the location of new generation capacity that is deployed. As such, the study is not intended to provide definitive capacity targets or to replace Duke Energy's traditional planning process, and it should not be considered a substitute for the Integrated Resource Plan (IRP) process or the forthcoming Carbon Plan under development for North Carolina. Despite these differences in the modeling approaches relative to other studies, this study provides insight into the generation capacity mix that could support the proposed decarbonization targets for Duke Energy.

Finding 1: Duke Energy can meet the 2030 emissions target in North Carolina through investments in a combination of solar PV, wind, and energy storage, along with maintaining its existing nuclear fleet. Figure ES-1 illustrates the estimated CO_2 emissions from different variations of the ReEDS 2030 and 2036 buildouts using the nodal production cost model. When considering only direct emissions, all the nodal modeling cases fall below the 2030 emissions target, although the exact emissions level depends on the scenario evaluated. For

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example, using the alternate load and weather profiles with the extended winter cold period results in higher emissions than under the baseline assumptions.

Accounting for emissions from imports might become increasingly important as Duke Energy increases interchanges with its neighbors However, the emissions intensity of imports is likely to change depending on additional policies enacted in the surrounding regions. Although the North Carolina policy does not include upstream emissions, we include estimates for the effects of methane leakage, which, under standard assumptions, would add approximately 1.7–2.5 million metric tons (MMT) of CO_2 equivalent annually.

This emissions estimate is in line with estimates of reductions in the policy scenarios from Duke Energy’s modified IRP as well as estimates from an independent study of policy options for reducing emissions in North Carolina (Konschnik et al. 2021; Duke Energy 2021). By 2030, 75% of the total annual generation will come from carbon-free energy resources (wind, solar PV, and nuclear), with 23% of generation coming from variable generation sources. Around 1% of total end-use demand is served by imports.

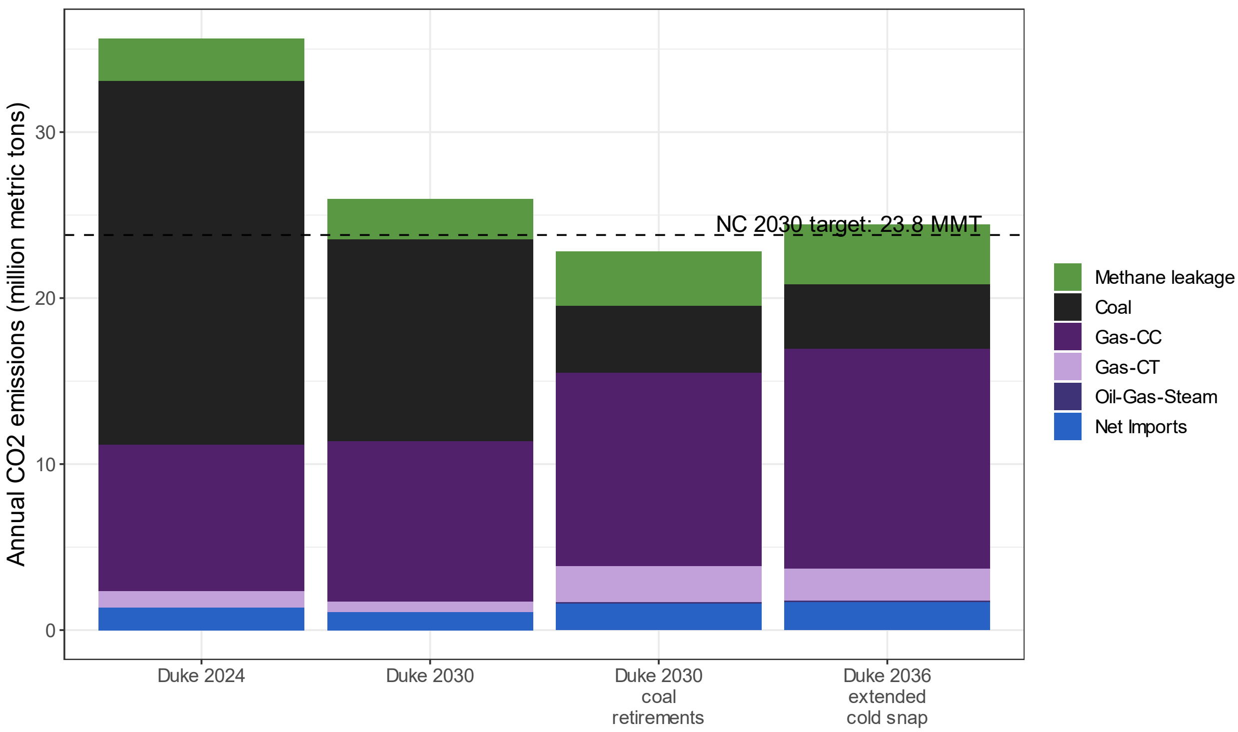

Figure ES-1. Total North Carolina CO_2 emissions for the 2024 base case and the 2030/2036 policy cases, as estimated by the nodal production cost modeling

Policy case results include sensitivities for coal retirements and for load and resource profiles corresponding to a year with an extended cold snap in the winter. The horizontal line reflects the North Carolina emissions target of 23.8 MMT for 2030 (70% reduction relative to 2005 levels). Note that the indirect emissions from methane leakage are not considered as part of the target. See Section 4.1.4 for details on the emissions estimation methods and a table of the values.

Operational modeling of the ReEDS buildout for the policy cases shows that the system could supply generation to meet load in all hours for a typical weather year. The analysis also tests whether the buildout can supply load in the event of a more sustained “cold snap” during the

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winter period[1]; in this case, generation is also able to serve load but relies more heavily on natural gas to meet demand during the winter peak period.

Approaching the 2030 target requires a substantial reduction in the share of generation provided by Duke Energy's coal fleet. The reduced generation from coal largely comprises increased generation from solar PV, wind, and energy storage. Natural gas contributes to meeting this goal as well—particularly by supplying generation in the winter period and ramping to balance solar PV generation—but maximum daily natural gas deliveries substantially increase in the policy cases, suggesting challenges with extensively relying on gas to meet demand during this period.

Sensitivities to different variable renewable energy (VRE, i.e., wind and solar) cost trajectories or technology developments, coupled with the value of resource diversity as the system achieves its interim target and moves toward zero-carbon emissions, suggest that there are benefits to early investments in a range of technologies. Both land-based and offshore wind provide complementary generation to solar PV, adding value toward meeting planning and operational requirements during times when solar PV has low availability. Similarly, research and planning options to provide clean, firm capacity—namely, the ability of zero-carbon resources to contribute capacity to meeting the system's planning reserve requirements—and energy storage of different duration levels should begin early, even if these resources play a more critical role at higher levels of decarbonization. The cumulative cost of CO_2 abatement for the interim 2030 target is approximately $7/metric ton (ranging from $6–$20/metric ton across key sensitivities).[2] These cost of mitigation estimates are based on additions of primarily solar and storage; to the extent that Duke Energy accelerates the deployment of other resources such as offshore wind—either for the purpose of resource diversification or in advance of planning to meet the 2050 zero-carbon emissions target—the actual cost of mitigation through 2030 may be higher than these estimates.

Finding 2: A zero-carbon emissions electricity sector target in 2050 can be achieved through investments in solar PV and battery energy storage, coupled with maintaining the existing nuclear fleet, building land-based and offshore wind, and procuring other zero-carbon emissions resources that supply firm capacity. Figure ES-2 illustrates the total installed capacity for the Carolinas in the reference and policy cases. We include two policy cases: one with a zero-emissions target in North Carolina but with the capability to use fossil fuel capacity as a backup to help meet the system's planning reserve margin and one where all fossil fuel resources must be retired across the Carolinas. From a generation scheduling perspective, the buildouts tested in PLEXOS for this study had no difficulty meeting the load requirements; nevertheless, more work is needed to understand the operations of a zero-carbon system from the standpoint of transient/dynamic stability, contingencies, and extreme weather events. The average cost of CO_2 abatement in the Carolinas from 2021–2050 ranges from $27–$33/metric ton (ranging from $9–$34/metric ton across key sensitivities).

[1] The baseline modeling assumptions use 2012 resource and load shape data, which had a relatively mild winter peak period. The extended cold snap sensitivity uses resource and load shapes from 2018, which had several days of cold weather that led to a large and sustained winter peak.
[2] Note that this cost of mitigation represents the average cost over all emissions reduced, and that typically the incremental cost of mitigation is higher since the cost to abate increases for greater emissions reductions.

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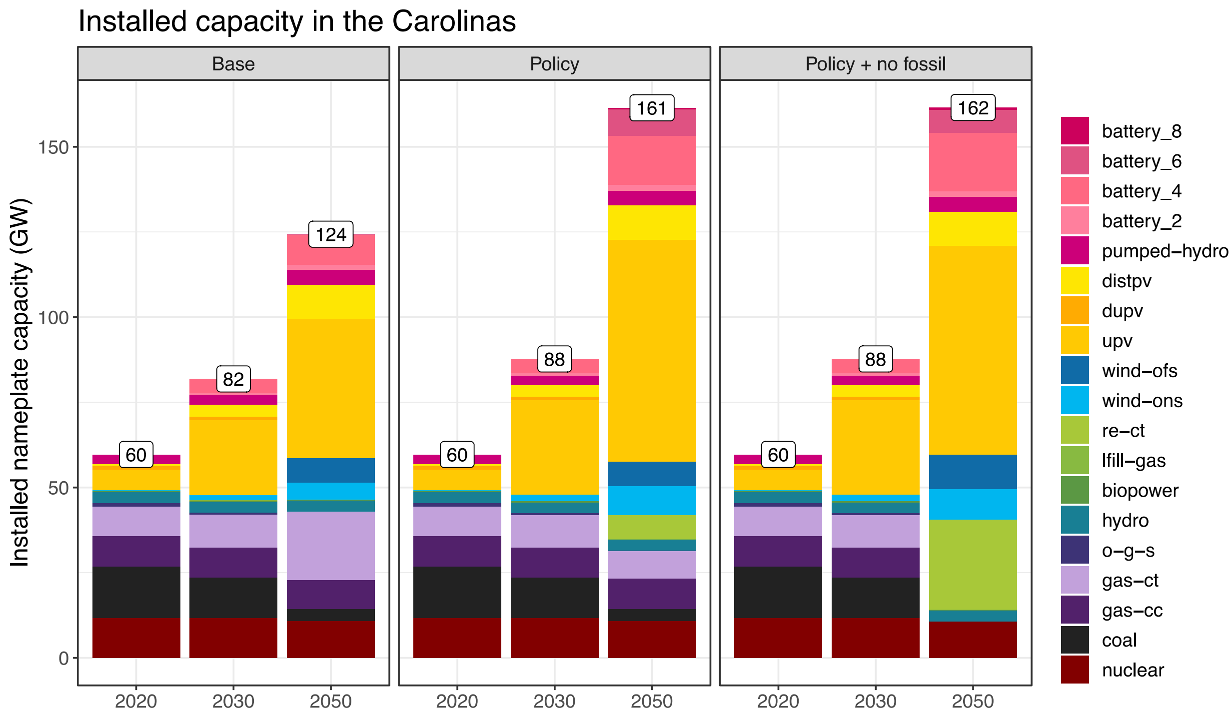

Figure ES-2. Installed capacity results by year (2020, 2030, and 2050) for the Carolinas for the main cases run in ReEDS

Base, policy, and policy with the requirement for no fossil fuel capacity in 2050

Eliminating the last 5%–10% of CO_2 from the power system presents new challenges and obstacles relative to the first 90%–95%. One key challenge is meeting planning reserve requirements—or, in other words, ensuring that sufficient generating capacity is always available to meet load. As the system moves closer to being zero carbon, the incremental contribution of VRE to firm capacity declines. To offset retiring firm capacity from coal and gas, larger amounts of VRE capacity are required, coupled with longer-duration energy storage that is then used to shift available energy from VRE surplus to times of the day with lower VRE output (evening, overnight, and morning). In addition to long-duration or seasonal storage, the deployment of other zero-carbon resources can help to sustain generation during extended (multiday) periods of low VRE resources and manage other contingencies. A reflection of the increasing challenge to eliminate the last tons of CO_2 from the system is the fact that the average *incremental* cost of CO_2 abatement increases from approximately $40/ton in 2048 to $75/ton for the policy case and $97/ton for the no-fossil fuel case in 2050, when the zero-carbon requirement in North Carolina is enforced. The difference between the costs of the two policy cases reflects the incremental cost of requiring all capacity needed to meet the planning reserve margin to be zero carbon. This cost difference also reflects the challenge of eliminating emissions leakage, as the policy case allows for North Carolina to rely on fossil generation imported from South Carolina.

Addressing the planning reserve challenge posed by the last 5%–10% of CO_2 emissions reductions needed to get to 100% carbon-free generation is facilitated by the availability of firm capacity, zero-emissions resources, a finding that has been well substantiated in the academic literature (Jenkins, Luke, and Thernstrom 2018; Sepulveda et al. 2018; Baik et al. 2021; Cochran et al. 2021). The modeling in this study primarily identifies renewable energy combustion turbines (RE-CTs) as the least-cost resource to meet this need,[3] but this technology could be any firm, zero-emissions generation opportunity, including combustion turbines fueled by hydrogen, small modular nuclear reactors, shifting VRE generation using seasonal storage, or demand response. A challenge of providing this capability is that these resources—though essential for ensuring reliability given the variability and uncertainty in VRE generation—are likely to have low capacity factors, implying that they need relatively low capital costs to be economic.

Technological advancements in the costs of these resources—through reductions in capital costs or the development of infrastructure to provide lower cost, zero-carbon fuel options such as hydrogen—will play a large role in reaching a 100% carbon-free target at lower cost. The requirement for firm zero-carbon resources—along with higher levels of VRE and longer-duration diurnal storage—increases the costs of mitigation relative to the first 90%–95% emissions reductions.

Achieving a zero-carbon power system requires a large buildout of new technology, with the installed capacity of Duke Energy's power system increasing by more than 1.5 times its current size even as load grows about 20% relative to today. This includes deploying approximately 60 GW of utility solar PV in the Carolinas, equivalent to approximately 2.2 GW of new PV capacity added annually from now until 2050. This annual deployment rate is four times larger than Duke Energy's annual average solar PV capacity additions in the Carolinas since 2014 (0.5 GW/year) and more than twice their estimate for the interconnection limit in their 2020 IRP (0.9 GW/year) (Duke Energy 2021). Deploying new capacity at the scale and rate required to meet the zero-carbon target thus poses logistical challenges in siting, interconnecting, and constructing new generation capacity.

Although most of this new capacity comes from technology that is commercially available today, some includes relatively novel technologies that are not yet deployed at scale, such as RE-CTs. Continued technological advancements and cost declines are likely to prove pivotal to enabling these pathways. Likewise, technologies such as seasonal storage, small modular nuclear reactors, and flexible loads were not directly included; cost declines or improvements in the availability of these technologies or others could further facilitate meeting Duke Energy's carbon-free goals.

Finding 3: Investments in new transmission and expanded power exchange with neighbors can play an important role in achieving both the 2030 target and a net-zero power system. Through 2030, the capacity expansion modeling identifies an additional 2.8 GW of interface transmission in the Carolinas under the policy target—a 20% increase from the values assumed in the modeling today—and nearly doubling all transmission capacity through 2050. Although the policy scenarios result in increased interface transmission buildout relative to the reference case, the reference scenario also invests in new transmission through 2030 (1.6 GW) and 2050 (7.2 GW). This outcome reflects the fact that there are sizeable "no regret" transmission investments that have high value under a range of policy outcomes. Important corridors for investment through 2030 include between eastern and western North Carolina and between western North Carolina and South Carolina. By 2050, however, nearly all routes—including

[3] This study assumes that RE-CTs could be supplied with zero-carbon fuel at a relatively high cost of $20/MBtu.

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those with Georgia and Virginia—show increased investment to manage resource availability across regions.

Expanded transmission—both within Duke Energy's territory and with its neighbors—reflects the fact that increased coordination with neighbors can help reduce the costs of meeting load across the combined regions and enhance the value of the wind and solar PV resources deployed as Duke Energy meets the 2030 policy target and moves toward a zero-carbon system**.** Operational modeling simulations show that transfers between Duke Energy and its neighbors increase in both frequency and magnitude as the share of VRE increase. Figure ES-3 illustrates the increase in energy interchange among Duke Energy's service territory and its neighbors from 2024 to 2030 as Duke Energy moves toward compliance with the 70% CO_2 emissions reduction policy target.

Increased use of transmission to support dynamic energy interchange helps reduce the total costs of balancing a high VRE system. Sensitivities that assume the adoption of zero-carbon targets in neighboring regions and enhanced regional coordination to enable firm capacity trades indicate less need for RE-CTs in the Carolinas, provided that transmission upgrades are implemented to support such capacity trades. These sensitivities include more adoption of offshore wind and longer-duration storage as neighboring regions also adopt more PV in pursuit of decarbonization goals, again assuming sufficient transmission support. At high contributions of carbon-free energy, accounting for the emissions intensity of imported power plays an important role in understanding the system's carbon footprint. New policies that facilitate that coordination and help plan transmission expansion across load-serving entities are likely to be an important enabler of the higher levels of power exchange between Duke Energy and its neighbors that are envisioned in this study.

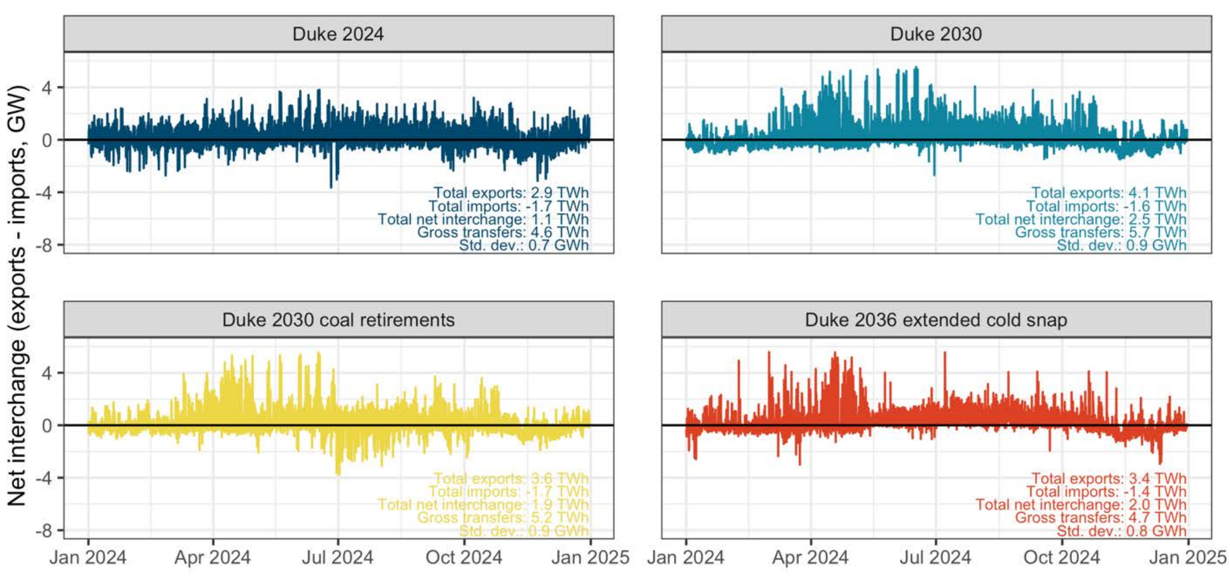

Figure ES-3. Hourly net export from Duke Energy to neighboring regions for the 2024 base case and the 2030/2036 policy cases using the nodal operational modeling results

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Finding 4: Flexible, zero-emissions technologies that can provide firm capacity are a critical component to meeting peaking needs not only in the summer but also, increasingly, in the winter as well. Duke Energy is already a "dual-peaking" system in that it experiences both a summer and a winter peak. As Duke Energy moves toward higher levels of carbon-free resource integration, however—including higher levels of solar PV and energy storage—the period of greatest system stress is likely to continue to shift to the coldest winter mornings, and this trend could be exacerbated by the potential electrification of space heating or electric vehicle adoption.

The left panel of Figure ES-4 illustrates dispatch in the Carolinas—including generation not in Duke Energy's service territory—during the winter net load peak, when load is high and output from renewable generation is relatively low. During summer nights, the system can rely on nuclear, wind, and energy storage alone to provide sufficient energy to meet load. When solar PV is not available, such as during winter nights, the zero-carbon system with no fossil fuel capacity relies on generation from RE-CTs combined with imports to meet energy needs. If Duke Energy does not wish to rely on imports, additional VRE plus energy storage, RE-CTs or similar technologies, or other zero-carbon resources that provide firm capacity could be used. The use of relatively high-operating-cost RE-CT resources reflects the challenges of serving load during this winter peak period. Using imports or RE-CTs could also be replaced with other dispatchable, clean technologies, such as seasonal energy storage.

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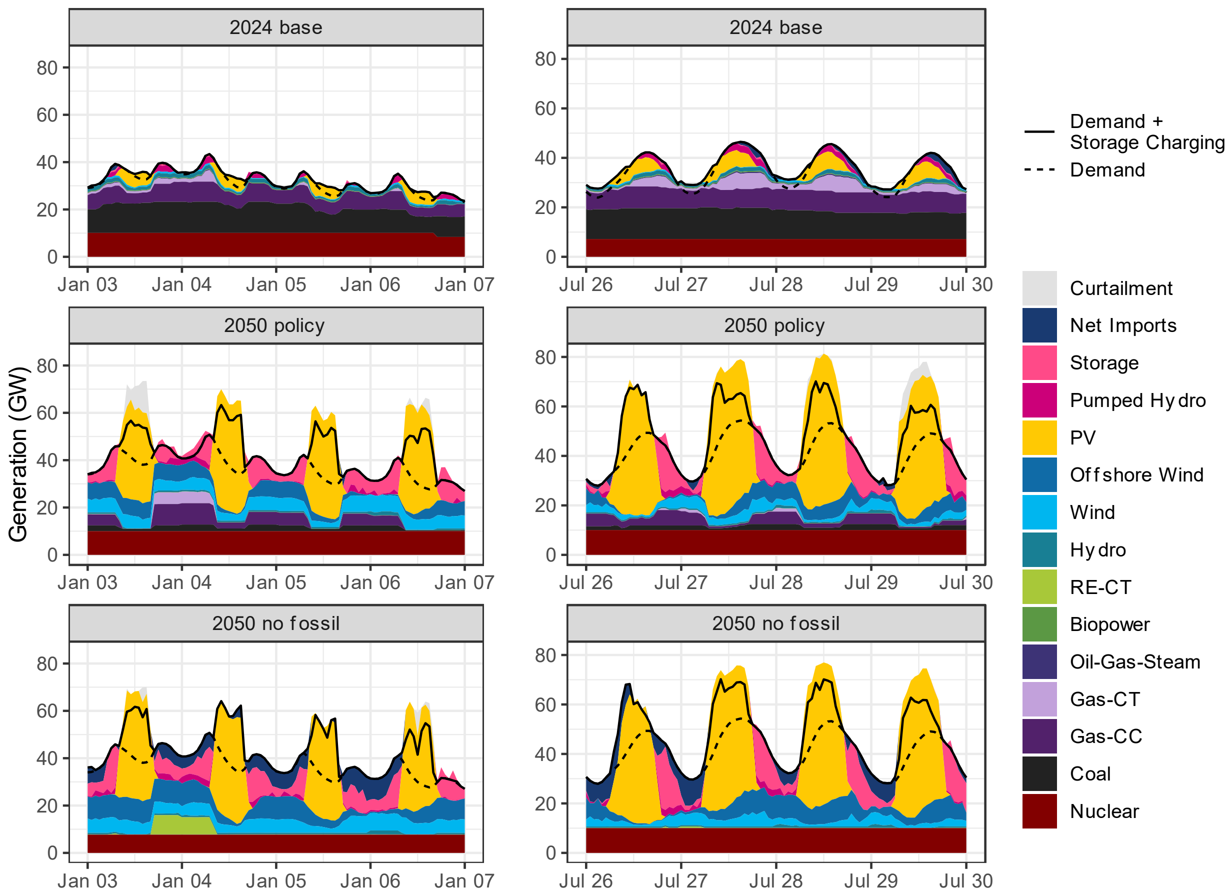

Figure ES-4. Generation dispatch for the 4 days surrounding the hour of the net load peak in the winter and summer for the 2024 base case and the 2050 policy cases

Results are shown using the zonal operational cost model, and they reflect the dispatch for the entire Carolinas, including systems that are not in Duke Energy's service territory.

With higher shares of wind and solar PV, operating reserve requirements become increasingly driven by the need to manage the variability and uncertainty associated with VRE resources. Energy storage is increasingly used to provide operating reserves, suggesting the importance of proper planning to ensure that sufficient state of charge is available to provide reserves and meet winter peak requirements. In this modeling effort, zero-carbon resources operating at low capacity factors play an important role in meeting demand and supplying operating reserves during the winter peaking period.

Importantly, the capacity expansion and production cost modeling in this analysis focus on a single, relatively normal weather year (2012), with a sensitivity analysis exploring an additional year with an extended cold period (2018) in the nodal operational analysis. Understanding the least-cost buildout and operational performance under a range of weather conditions is an important component to fully understanding the capability of these carbon-free systems, and future analyses could focus on operational performance assessments under distinct weather realizations and changing climate patterns.

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Finding 5: As Duke Energy transitions to lower-carbon generation resources, it can expect the capital share of total bulk system costs or expenditures to increase while the operational share decreases. Figure ES-5 presents estimates of annualized, undiscounted system costs in 2050. With the retirement of fossil fuel resources and their replacement with low- or zero-marginal-cost resources, operational costs from fuel and variable operation and maintenance are likely to substantially decline; however, the capital cost intensity of VRE and the subsequent need for firm clean capacity—including some resources that have very low utilization—drive increased capital expenditures relative to operational costs. In addition, increased trade with neighboring regions could imply higher costs related to importing firm power. Importantly, the cost estimates in this study include only bulk system costs and thus do not account for costs from distribution systems, energy-efficiency or demand response programs, administrative costs, or servicing existing debt.

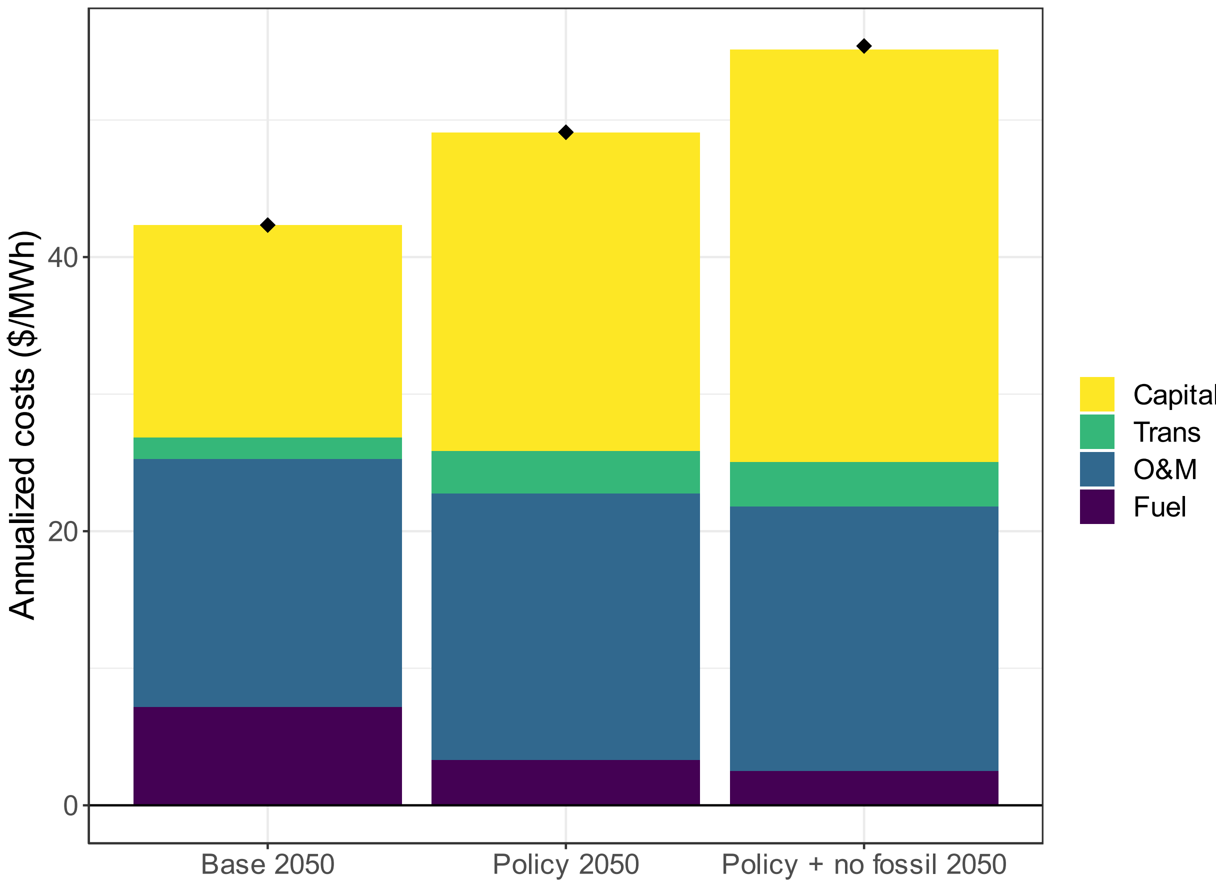

Figure ES-5. Annualized, undiscounted cost estimates (U.S. 2020 $/MWh) for the 2050 policy cases and the 2050 base case

Note that these estimates do not include costs for imported power.

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1 Introduction

Duke Energy is one of the largest electric power holding companies in the United States, serving nearly 8 million customers over five states (Duke Energy 2019). Approximately half these customers are located in the Carolinas and are served by two Duke Energy subsidiaries: Duke Energy Carolinas and Duke Energy Progress. Together, these two subsidiaries operate approximately 33 GW of installed generating capacity, with an additional 3 GW of distributed energy resources interconnected to the distribution system. Figure 1 depicts the combined service territory of Duke Energy's Carolina subsidiaries, along with the location of major generating power generation facilities.

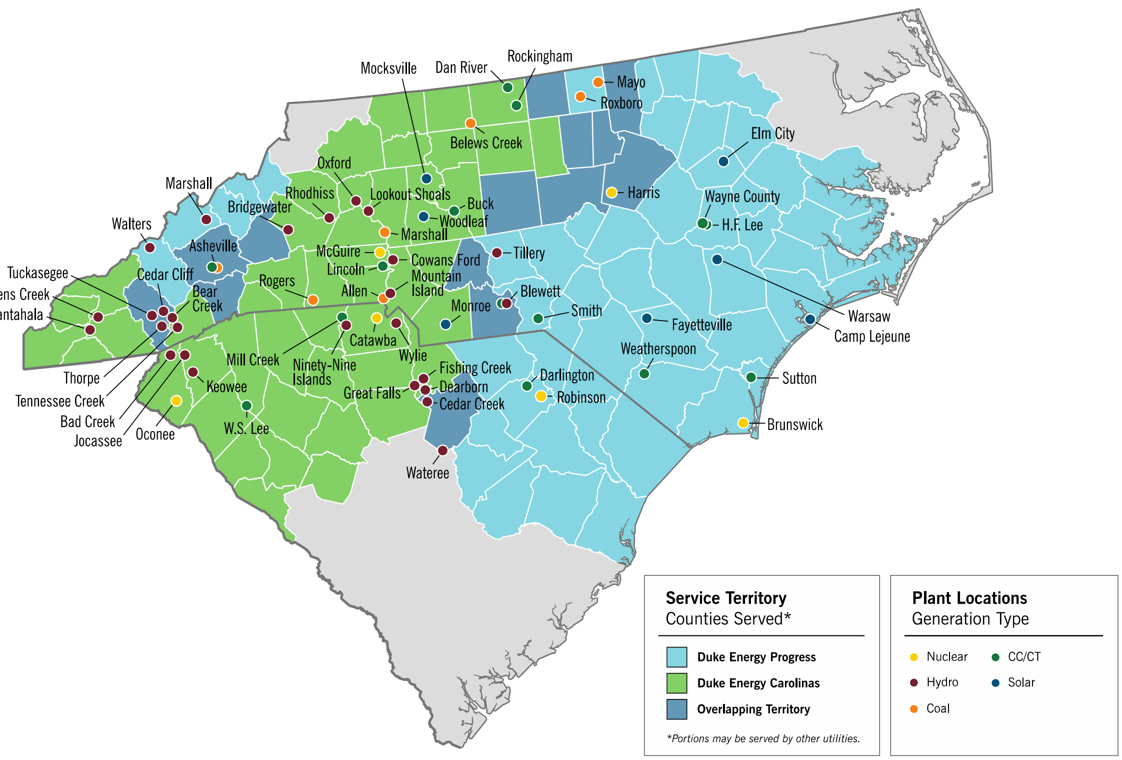

Figure 1. Depiction of Duke Energy's service territory in the Carolinas

Source: Duke Energy 2020b

In 2019, Duke Energy committed to reducing carbon dioxide (CO_2) emissions on its electricity system by 50% from 2005 levels by 2030 (Duke Energy 2020a), and the state of North Carolina has proposed a 70% reduction target by that date. In addition, Duke Energy is targeting to achieve net-zero carbon emissions from the electric sector by 2050, a goal that is in line with policy targets announced in the North Carolina Clean Energy Plan and in recently passed legislation.[4]

[4] North Carolina codified the 2030 and 2050 targets with House Bill 951: *Energy Solutions for North Carolina,* which was passed and signed into law in the fall of 2021.

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Given these targets, Duke Energy is committed to evaluating the costs, challenges, and benefits of integrating higher levels of low- and zero-carbon electricity generation into their Carolinas system. To that end, Duke Energy has partnered with the National Renewable Energy Laboratory (NREL) to evaluate pathways to achieving their carbon-free resource integration targets and to assess the operational behavior of the resulting system.

The Duke Energy Carbon-Free Resource Integration study included two phases. In Phase 1, NREL and Duke Energy conducted a net load analysis evaluating the operational impacts of higher solar photovoltaic (PV) shares in the Carolinas. The findings of the Phase 1 study were published in a separate technical report.[5]

The objectives of Phase 2 were to understand the pathways to integrating carbon-free power using more sophisticated modeling tools and data sets than in Phase 1, and this report focuses on the methods and results from Phase 2. Phase 2 consisted of three separate but interrelated analyses:

1. **Resource assessment**: determination of the technical and economic potential and characteristics of wind and solar PV resources in the Carolinas
2. **Capacity expansion**: identification and analysis of least-cost investment pathways to achieving 70% CO_2 reductions in North Carolina by 2030, along with a net-zero electricity system by 2050
3. **Operational modeling**: detailed production cost modeling of power system operations at these higher shares of low- and zero-carbon generation resources, informed by the capacity expansion modeling portion of the analysis.

Figure 2 depicts the analysis workflow for the Phase 2 study. Data and results from each level of analysis were used to inform the other levels, with iterations between levels as appropriate.

[5] The Phase 1 report and Phase 2 materials are available at https://www.nrel.gov/grid/carbon-free-integration-study.html.

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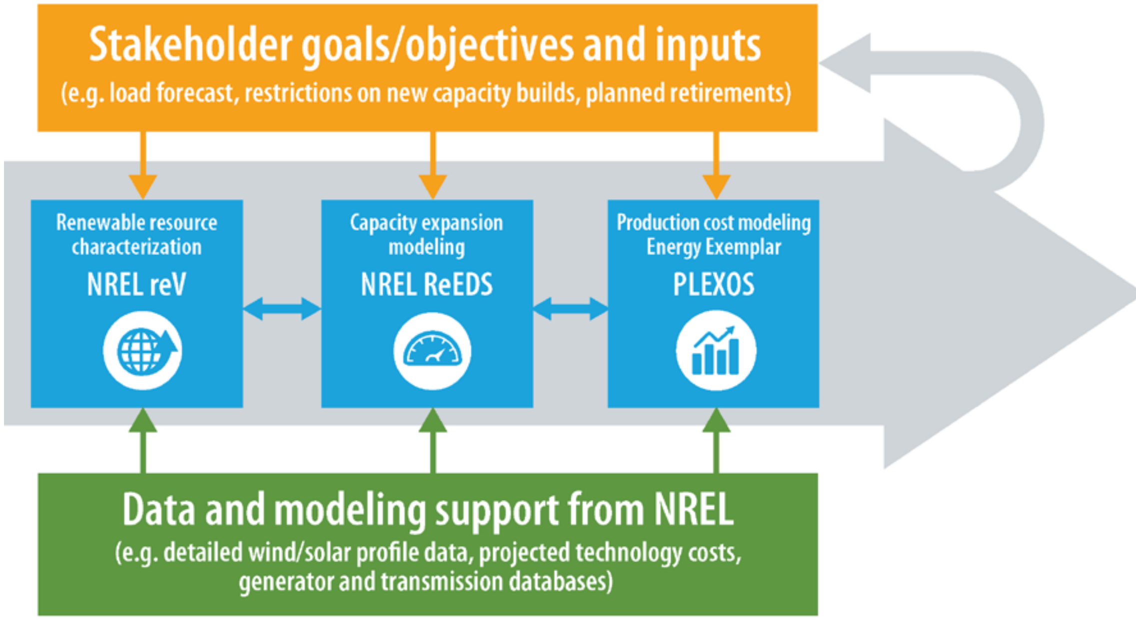

Figure 2. Depiction of the modeling workflow conducted in Phase 2 of the Duke Energy Carbon-Free Resource Integration Study

This report details the findings of Phase 2. Section 2 outlines the analysis methods, including details on the data sets, modeling approaches and scenarios for the renewable resource characterization, capacity expansion modeling, and production cost analysis. Section 3 presents the findings of the study related to investment pathways, including insights from the resource assessment and capacity expansion modeling. Section 4 presents operational insights from the production cost modeling. Finally, Section 5 summarizes the overall findings of the study.

The findings of this study are directionally consistent with previous assessments of decarbonization pathways in the Carolinas and more broadly across the United States, although specific outcomes might differ depending on modeling assumptions. For example, this analysis focuses on the capacity mix that can achieve the decarbonization targets, but it does not evaluate how the timing of new capacity builds might be impacted by supply chain constraints, construction logistics, or the need to incorporate findings from more detailed transmission planning studies that are inclusive of AC power flow analysis. Accounting for these types of constraints might affect the speed at which new capacity can be deployed, resulting in changes to the rate of new capacity builds or even the total mix used to meet the 2030 target.

Also, this study was initiated before more recent proposals to accelerate the retirement of some units of Duke Energy's existing coal fleet, particularly the subcritical units. Although we were unable to revise the capacity expansion modeling runs to assess this pathway, we test a sensitivity in the production cost modeling that evaluates a system with these accelerated coal retirements as well as one that explores a 2036 case with coal retirements and offshore wind. Changes to the coal retirement schedule or other buildout schedules could result in different pathways to meeting the 2030 target relative to the findings of this study, including the deployment of additional natural gas in the short term for meeting planning reserve and seasonal peak energy requirements.

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Other modeling assumptions—such as the consideration of dynamic or transient stability, contingency analysis, nodal transmission expansion, or gas pipeline constraints—can also affect the quantity and the location of new generation capacity that is deployed. As such, the study is not intended to provide definitive capacity targets or to replace Duke Energy's planning process, and it should not be considered a substitute for the Integrated Resource Plan (IRP) process or the forthcoming Carbon Plan under development for North Carolina. Despite these differences in modeling approaches relative to other studies, this study provides insight into the investment pathways to a generation capacity mix consistent with Duke Energy's decarbonization targets.

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2 Study Methods

As detailed in the introduction, the Phase 2 study linked three levels of analysis: (1) an assessment of the renewable resource in the Carolinas, (2) the identification and evaluation of alternative technology pathways to achieve Duke Energy's carbon reduction targets using capacity expansion modeling, and (3) an operational analysis of the resulting generation mix using production cost modeling tools. This section provides details on each tool, method, and assumption used in each analysis level.

2.1 Resource Assessment

Characterization of the renewable resource potential in the Carolinas is a critical step for understanding the potential investment pathways that might enable Duke Energy to achieve its carbon reduction targets. Such a characterization includes not only quantifying the raw *technical* potential of wind and solar PV power resources but also constraining that technical potential to a *developable* potential by incorporating the impacts of any siting limitations associated with regulatory restrictions, land availability, and potential social barriers.

To accomplish this resource assessment, we employ NREL's Renewable Energy Potential (reV) model (Maclaurin et al. 2019; Rossol, Buster, and Bannister 2021). The reV model is an open-source tool that integrates data on renewable energy resources, technology performance and plant costs, and siting constraints to create highly spatially and temporally resolved data that characterize the availability and quality of wind and solar PV power generation resources.[6] The reV model also provides the corresponding wind or solar PV profile for any new capacity developed at any feasible site within the assessed wind and solar PV potential. The reV model is highly spatially resolved, with wind and solar PV profiles data characterized at 2-km x 2-km and 4-km x 4-km resolution, respectively, and siting constraints based on land use and cover data as detailed at a 90-m resolution (Lopez et al. 2021).

Figure 3 provides an overview of the reV modeling workflow and outputs. The reV analysis for this study begins by drawing on spatially detailed historical weather data (explicitly, wind speeds and global horizonal irradiance) to characterize each resource. Weather data for reV are taken from the Wind Integration National Dataset (WIND) Toolkit (Draxl et al. 2015) and the National Solar Radiation Database (NSRDB) for solar PV (Sengupta et al. 2018). This study uses hourly weather profiles from 2012 for the resource assessment.

[6] Documentation and access to the reV model are available at https://www.nrel.gov/gis/renewable-energy-potential.html.

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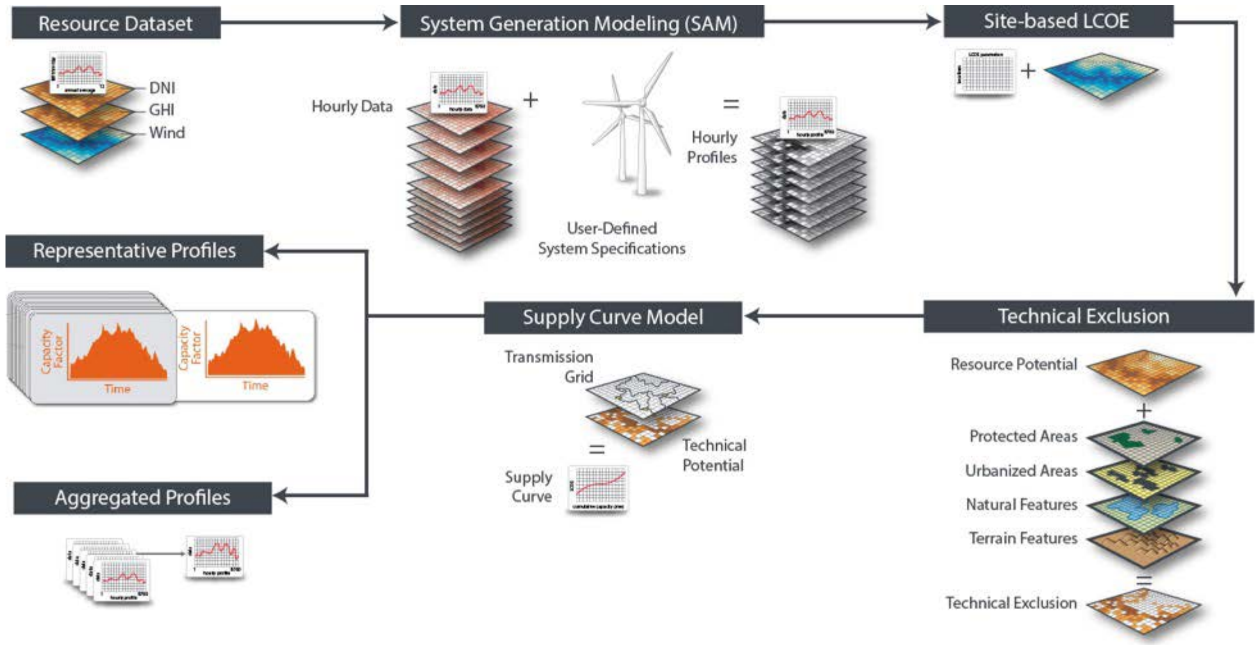

Figure 3. Depiction of the reV modeling process

Source: Lopez et al. 2021

Using these weather data, reV leverages NREL's System Advisor Model (SAM) to simulate power production from wind and solar PV installations at each candidate location. In general, wind turbine and solar PV utility-scale configuration assumptions were based on the NREL 2019 Annual Technology Baseline (ATB) and default parameters in SAM. Land-based wind turbines are assumed to have a hub height of 110 m, although we conduct a sensitivity analysis exploring the resource assignment implications of larger turbines. Details on the system configurations used for the reV analysis can be found in Appendix A.

After developing hourly generation profiles for all potential wind and utility-scale solar PV sites—aggregated to 33.2-km^2 resolution for both wind and solar PV—the model then uses geospatial data that characterize the spatial extents of non-developable land area to eliminate all sites that would not be feasible for siting new generation. These exclusions capture important elements that can restrict renewable resource development, including:

- Terrain slope (or steepness), with 5% for solar PV and 25% for wind
- Setbacks[7] from roads, rails, buildings, and other infrastructure (1.1 times turbine tip height)
- Water bodies and wetlands
- Urban areas
- Military bases
- Parks, recreation and wilderness areas, and other protected lands.

[7] Setbacks refer to the minimum distance from the relevant infrastructure type that a renewable generation facility could be sited.

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The exclusions used for this study are generally in line with those corresponding to the "reference access" scenario propose in Lopez et al. (2021). In addition to those base exclusions, the following sites and areas were also excluded:

- Sites exceeding 3,000 ft in elevation in North Carolina; this exclusion was added to account for potential difficulty in building wind turbines on ridgetops given existing restrictions in North Carolina.[8]
- Sites in close proximity to radar or military sensing equipment; a buffer of 4 km is used for Next-Generation Weather Radar (NEXRAD) and 9 km for short- and long-range radar.

Additional sensitivities are also performed on a "limited access" scenario that excludes turbines in all radar line-of-sight, which accounts for topographic effects when considering radar viewshed.

After the exclusion layers are applied, the result is a set of feasible wind and utility-scale solar PV sites with corresponding hourly generation profiles. The set provides the total potential generation resource that could be considered for development. Figure 4 and Figure 5 provide geospatial depictions of the candidate sites in the Carolinas for wind and solar PV, respectively, after considering exclusions. After the exclusions are applied, in the baseline scenario there is a total 74.6 GW of potential land-based wind capacity and 1,160 GW of potential utility-scale solar PV capacity in the Carolinas. The model also assumes more than 600 GW of offshore wind potential, although further analysis is needed to determine how much of the potential area would be feasible for offshore wind development given potential regulatory and technical limitations.[9]

[8] The 1983 Mountain Ridge Protection Act passed by the North Carolina General Assembly allows counties and cities to enact restrictions on buildings and structures on or near ridgetops at 3,000-ft elevation. Although the law contains exceptions for "windmills," there is some uncertainty about how this might impact wind turbine development in practice (Heath 1984).
[9] Offshore wind development primarily occurs by obtaining a federal lease. There are two primary offshore wind lease areas in the Carolinas: Carolina Long Bay to the south and Kitty Hawk to the north.

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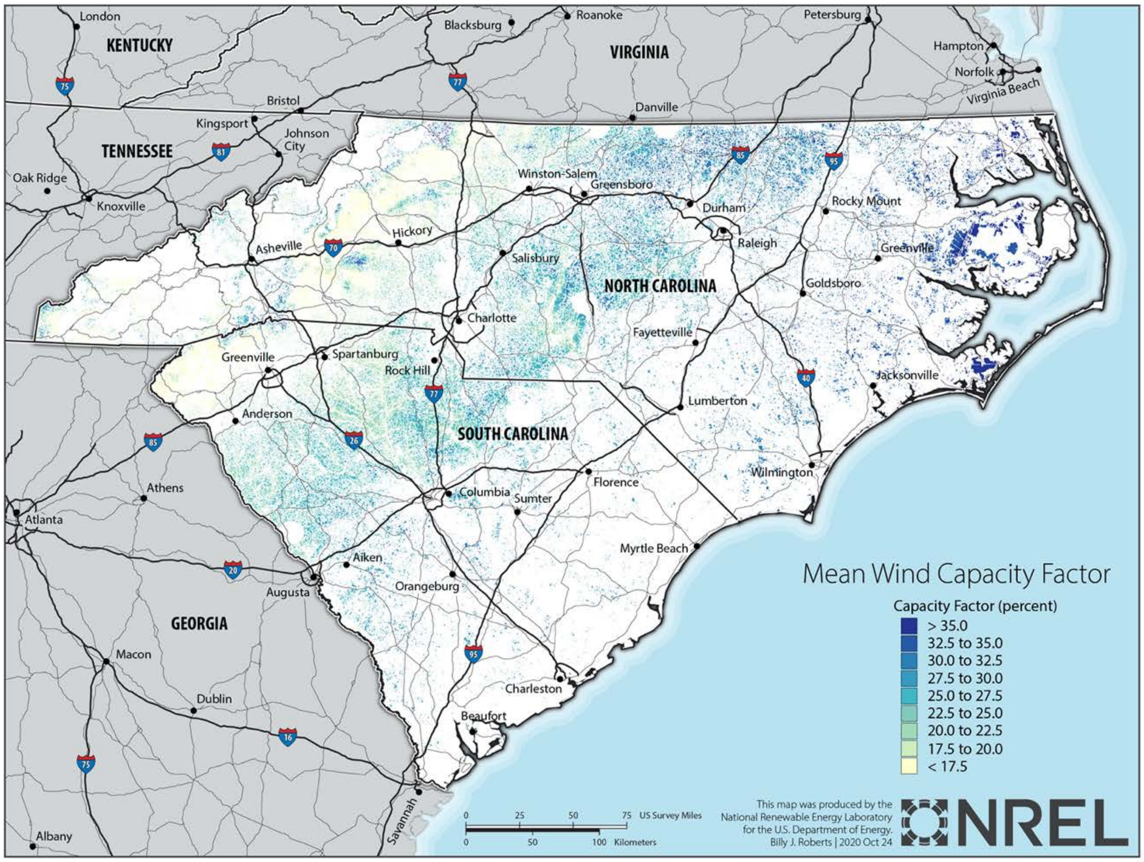

Figure 4. Mean annual land-based wind capacity factors for potential sites in the Carolinas under baseline wind exclusion assumptions

The white areas indicate excluded sites for land-based wind. Note that these maps convey technical potential after considering resource quality and exclusions; siting decisions must consider not only these data but also other considerations, such as the suitability of the transmission network to accept new capacity. See Appendix A for a geospatial depiction of the limited wind resource assessment.

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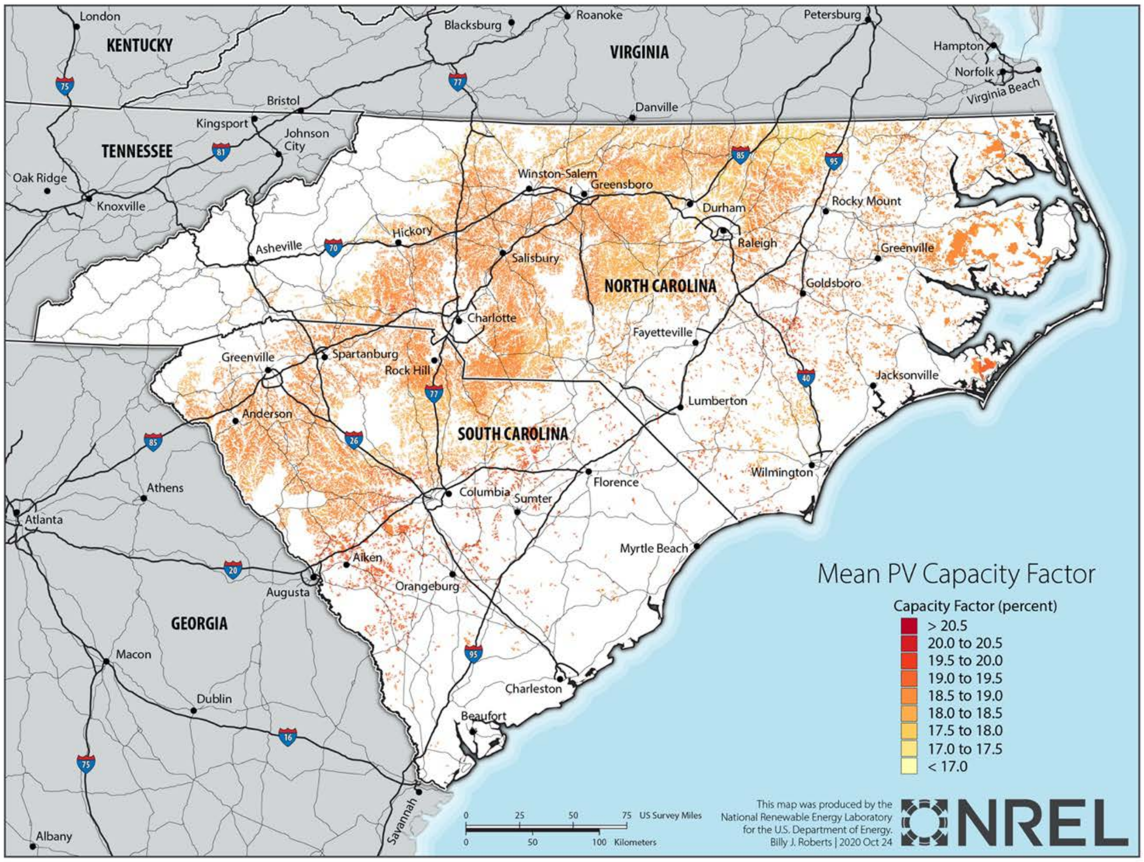

Figure 5. Mean annual solar PV capacity factors for potential sites in the Carolinas

The white areas indicate excluded sites for utility-scale PV. Note that these maps convey technical potential after considering resource quality and exclusions; siting decisions must consider not only these data but also other considerations, such as the suitability of the transmission network to accept new capacity.

By considering the profiles of the technically feasible sites, assumptions on capital costs for the system configurations studied, and other costs such as spur line transmission investments, the reV model can also calculate the total installed costs of the available resource. Integrating these estimates results in a resource supply curve that describes the cost of wind or solar PV resources as a function of the resource deployed.

Figure 6 depicts the land-based and offshore wind supply curves from this analysis (see Appendix A for details on wind resource class break points). Note that although we provide the reV estimates of the levelized cost of energy (LCOE) for the resource supply curve, the capacity expansion portion of this study does not use LCOE to determine how much generation to build. Instead, the model evaluates the total cost—inclusive of capital, operation, and maintenance—of each investment in all feasible locations against the system value it provides when determining build decisions (see Section 2.2 for more discussion).

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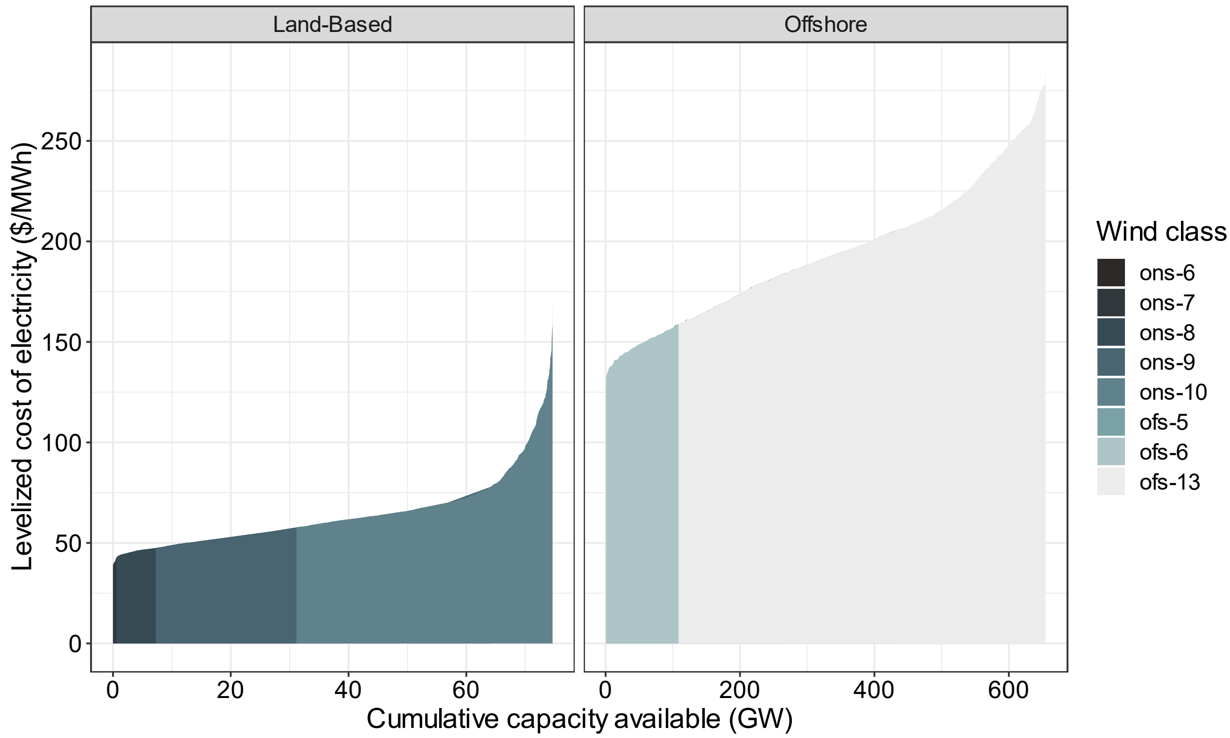

Figure 6. Wind supply curves from the reV resource assessment for the default wind resource characterization

We develop two sensitivities to the base case for the wind resource assessment. The first simulates a "limited land-based wind access" scenario in which all turbines in any radar line-of-sight viewshed are excluded from the resource set. This viewshed is calculated based on distance from radar sites and accounts for the effect of the area's topology. Consideration of this exclusion reduces the total available land-based wind supply curve to approximately 10 GW of land-based wind capacity.

The second sensitivity entails accounting for anticipated advancements in turbines. These advancements primarily include higher hub heights (120 m compared to the default assumption of 110 m for land-based wind), and larger turbines (5.5 MW compared to the default assumption of 2.3 MW). The sensitivity also assumes improvements to offshore wind technology. Appendix A provides details on the technology assumptions and power curves for the different turbines in the analysis.

The increased hub height of the land-based wind turbines reduces the amount of the total available supply curve to 59 GW because of the need for greater setbacks (e.g., from roads, rivers, urban areas, and buildings), but it also improves the wind profiles by capturing more consistent, stronger winds at higher altitudes, increasing annual energy production, and thus reducing the levelized cost of deploying land-based wind resources. Figure 7 compares the land-based supply curves across the three cases.

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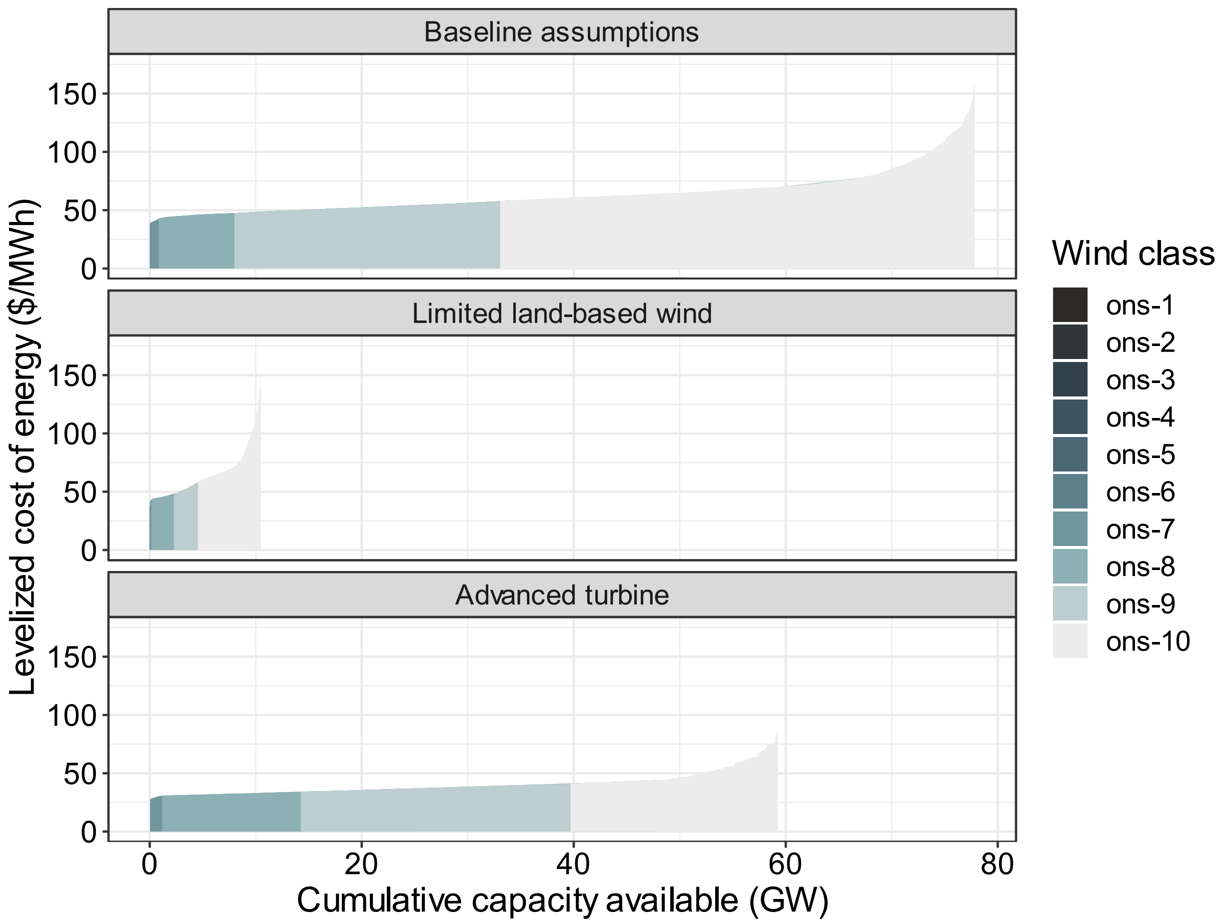

Figure 7. Land-based wind supply curves from the reV resource assessment for the wind turbine sensitivities

The top panel depicts the baseline assumptions, the middle panel depicts a "limited" wind deployment in which all line-of-sight radar is excluded, and the bottom panel depicts a scenario with more advanced turbines.

Note that the resource assessment serves as one of many inputs to the other modeling stages. In both the capacity expansion modeling and nodal siting parts of the analysis, information on resource quality is evaluated against other aspects—such as network topology, load shape and growth, cost of resources, availability of complementary resources, and other factors—to determine the location of new investments. In some cases, these modeling approaches will make trade-offs by building wind and solar PV in areas with lower capacity factors to satisfy other constraints and minimize total system cost. The next section (Section 2.2) describes the capacity expansion modeling process in more detail, and Section 2.3.2 provides additional information on how the resource assessment data and capacity expansion results are used along with other data (such as transmission availability) to site new wind and solar PV generation in the nodal operational model.

2.2 Capacity Expansion Modeling

This study employs the Regional Energy Deployment System (ReEDS™) model to provide insight into the investment decisions and capacity mix that can advance Duke Energy's carbon-free resource integration objectives in the Carolinas. ReEDS is a capacity expansion tool that

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simulates the evolution of the bulk power system from the present day through 2050.[10] ReEDS identifies the least-cost capacity mix that can meet load and planning requirements and that otherwise fulfills operational, environmental, and policy constraints. In addition to data on the resource supply curves developed in the reV analysis for this study, ReEDS considers data on the capital and operating costs of the full suite of generation technologies, load shape and projected growth, operational and policy requirements, and a range of other inputs to evaluate the mix of generating capacity needed.

This section provides a brief overview of the ReEDS model as applied to this study as well as the scenarios modeled in the capacity expansion analysis. Readers interested in the full details on the model should consult the ReEDS model documentation (Brown et al. 2020).

2.2.1 Description of ReEDS Modeling Approach

ReEDS is a continental-scale capacity expansion model that simulates the evolution and operation of generation and transmission infrastructure from the present day to the mid-century, as well as end-use demand (Brown et al. 2020). The model is frequently run for the entire contiguous U.S. or North America as a whole, but it can also be run on smaller regions, such as the U.S. interconnections. As applied in this study for Duke Energy, the model includes two primary components:

- A supply module that solves a linear program for the cost-minimizing levels of power sector investment and operation
- A variable renewable energy (VRE) module used to calculate parameters related to the value of VRE generation, including capacity credit, curtailment, and interaction with storage.

The ReEDS model employs these two modules to solve for investments over time. ReEDS can be run with a range of different foresight settings, from sequential (a solution in year *t* includes no information about the state of the world in year *t+1* or beyond) to fully intertemporally optimized (the model has access to all investment time step periods and solves them simultaneously). For the Duke study, we employ the sequential model. Figure 8 depicts the interaction of the supply and VRE modules when using the sequential solve approach.

[10] Details, documentation, and access to the standard ReEDS model can be found at https://www.nrel.gov/analysis/reeds/about-reeds.html.

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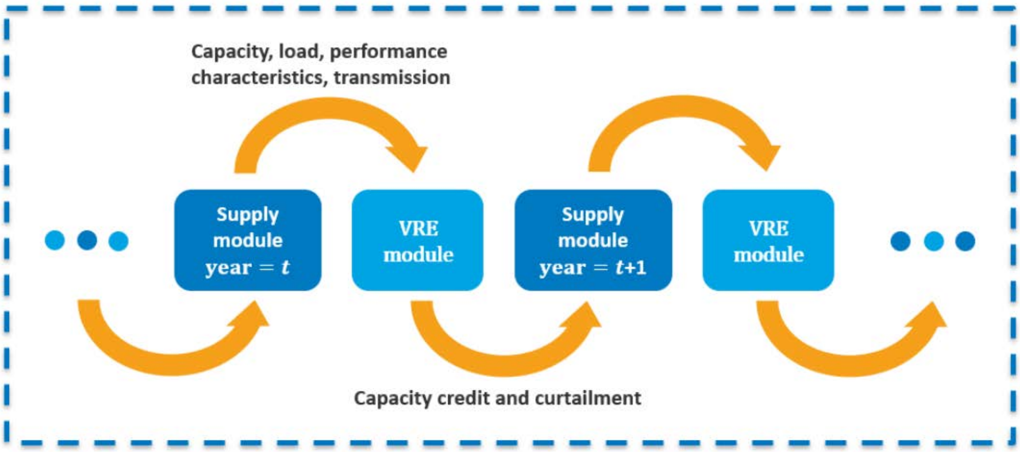

Figure 8. Depiction of the ReEDS modeling framework for the sequential solve

Source: Brown et al. 2020

The ReEDS supply module is a linear optimization program that identifies the least-cost suite of generation, transmission, and storage investments required to meet load in all time slices while simultaneously satisfying all other system (such as power system operations) and policy constraints (such as emissions constraints or renewable/clean energy standards). Major categories of constraints in ReEDS include:

- **Load balance**: Each modeled balancing area must generate or import sufficient power to meet load at all times.
- **Planning reserve**: Each region must have sufficient available capacity to meet expected peak load conditions plus an additional margin—the planning reserve margin—included to ensure that sufficient capacity is available even in cases of a component failure. Planning reserve margins in ReEDS are based on the North American Electric Reliability Corporation identified targets.
- **Operating reserves**: Each region must have available capacity to meet the specified operating reserve needs that are held to manage uncertainty and variability in load and generation. Three operating reserve products are specified in ReEDS: flexibility, regulation, and contingency reserves.
- **Generator constraints**: Generators are subject to technology-specific constraints on their operations, such as ramp rates and minimum loading.
- **Transmission**: Power flow transfers between modeled balancing areas are constrained by the aggregate capacity of lines between regions.
- **Resource constraints**: The total capacity of deployed renewable energy technologies is limited by the spatially explicit availability of the resource.
- **Policies**: All state and regional CO_2 constraints and renewable or clean energy standards enacted as of June 2020 must be satisfied. ReEDS also includes federal policies, such as the production and investment tax credits.

The optimization is calculated within the model through minimizing the “objective function,” which calculates the total costs of investment in and the operation of generation, transmission, and storage resources to meet load, resource adequacy targets, and operating reserve needs from the present day through 2050. Costs accounted for in the objective function include the present value of the cost of new investments in generation, storage, or transmission capacity (inclusive of financing costs), fuel costs, and fixed and variable operation-and-maintenance costs associated with supplying generation to meet load and operating reserve requirements. Additionally, the optimization considers the costs of other policy-based incentives or penalties.

ReEDS models multiple levels of spatial granularity relevant to this study. The first is the modeled balancing area, which serves as the primary level of spatial aggregation within the model. At this level of regionality, thermal generation resources are specified, and load and operating reserve requirements are enforced. Transmission capacity limits are also defined between balancing areas. The model includes 134 modeled balancing areas for the continental United States and represents the Carolinas with four balancing areas: two in North Carolina and two in South Carolina. Figure 9 depicts the modeled balancing area and transmission representation used in the ReEDS model.

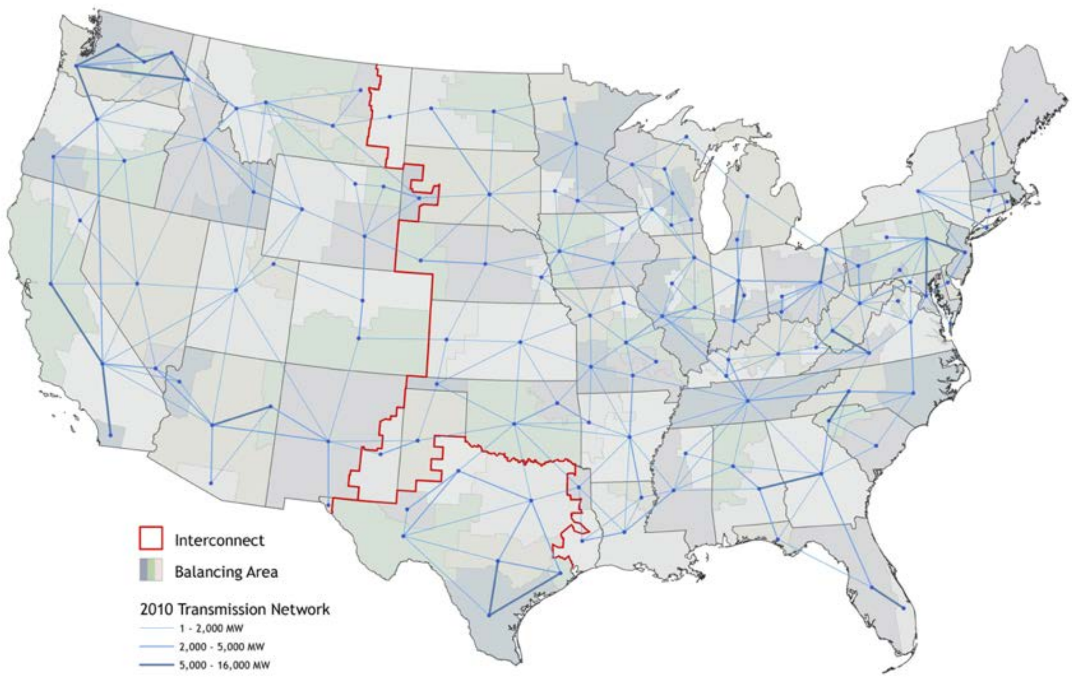

Figure 9. Modeled balancing area and transmission representation in ReEDS

Source: Brown et al. 2020

Although ReEDS characterizes the solar PV resource at the balancing area level, it uses a finer geographic resolution for wind resources. A total of 356 wind resource regions are defined across the United States. Within each wind resource region, detailed resource point information from the resource characterization using the reV model is aggregated to construct supply curves of the total available wind resource by resource class. Each supply curve point is assigned a representative 8,760-hour resource profile for that region and wind class. For both wind and solar PV, this information is used to characterize not only the availability of the resource in each

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representative time slice but also in the capacity credit,[11] curtailment, and storage dispatch calculations specified within the VRE module, discussed in more depth at the end of this section. Figure 10 illustrates the wind resource regions and modeled balancing authority demarcations for the Carolinas.

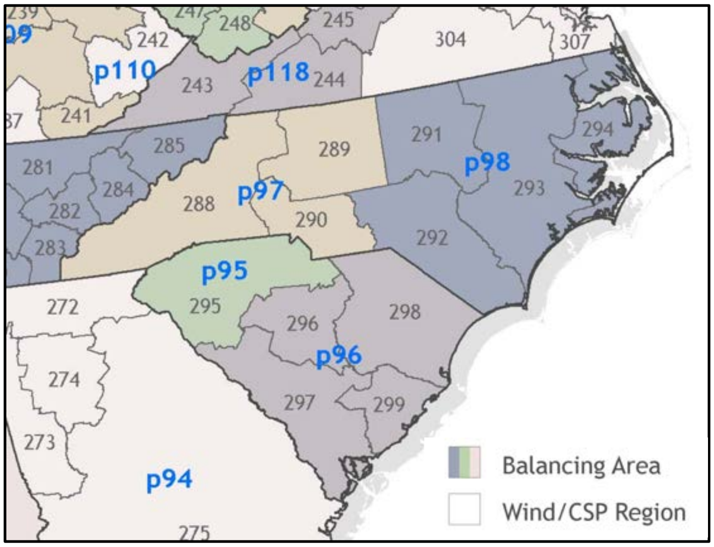

Figure 10. Depiction of wind resource regions (gray outlines) and modeled balancing authorities (shaded areas with blue numbers) in the Carolinas

Source: Brown et al. 2020

ReEDS also considers some larger geographic extents for specific calculations, policy requirements, and other planning constraints. For example, ReEDS captures national and state-level policies related to emissions, clean energy or renewable portfolio standards, and financial incentives (including the production and investment tax credits for renewable energy and the 45Q tax credit for carbon capture and storage technologies). ReEDS captures state and local policies codified as of June 2020 and includes the federal tax credit extensions passed in December 2020. Similarly, constraints related to the planning reserve margin are specified at the North American Electric Reliability Corporation region level (North American Electric Reliability Corporation 2010).

Multiple temporal resolutions are used within ReEDS to capture power system operational details. In the supply module used to determine capacity investments, ReEDS simulates system dispatch and operations in aggregate using representative time slices to capture the operations of a typical day in each season as well as the peak load conditions in the year. Under the default formulation, ReEDS uses 17 time slices: 16 of these time slices represent four times of day (morning, afternoon, evening, and overnight) across four seasons (spring, summer, fall, winter),

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[11] The "capacity credit" associated with a technology is the fraction of a generating unit's nominal capacity that can be counted toward the total planning reserve target—often defined based on the period of highest load or system stress. Because wind and solar resources are variable in nature, the likelihood of their availability during peak load (or stress) conditions must be considered, which depends on the shape of the load, the generation profile of the specific resource, and the flexibility in the system (through storage, demand response, and the ability of thermal generation to ramp). As such, wind and solar resource capacity credits can vary from very high (>70% for solar at low VRE levels) to very low or even zero (e.g., solar at very high VRE levels).

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whereas the 17th time slice is used to capture the summer afternoon peak. Because Duke Energy has experienced high system demand during winter periods in the past, an 18th time slice was added to capture peak system load during winter mornings. Table 1 provides details on these time slices. Hourly load and resource data are aggregated and averaged for each time slice for dispatch in the supply module, which are then used to determine the investment requirements.

Table 1. Definition of ReEDS Time Slices

Note that the H18 winter peak time slice was added to ReEDS for this study.

Source: Brown et al. 2020

Time Slice	Hours/Year	Season	Time of Day	Period
H1	736	Summer	Overnight	10 p.m.–6 a.m.
H2	644	Summer	Morning	6 a.m.–1 p.m.
H3	328	Summer	Afternoon	1 p.m.–5 p.m.
H4	460	Summer	Evening	5 p.m.–10 p.m.
H5	488	Fall	Overnight	10 p.m.–6 a.m.
H6	427	Fall	Morning	6 a.m.–1 p.m.
H7	244	Fall	Afternoon	1 p.m.–5 p.m.
H8	305	Fall	Evening	5 p.m.–10 p.m.
H9	960	Winter	Overnight	10 p.m.–6 a.m.
H10	820	Winter	Morning	6 a.m.–1 p.m.
H11	480	Winter	Afternoon	1 p.m.–5 p.m.
H12	600	Winter	Evening	5 p.m.–10 p.m.
H13	736	Spring	Overnight	10 p.m.–6 a.m.
H14	644	Spring	Morning	6 a.m.–1 p.m.
H15	368	Spring	Afternoon	1 p.m.–5 p.m.
H16	460	Spring	Evening	5 p.m.–10 p.m.
H17	40	Summer	Summer peak	40 highest hours of H3
H18	20	Winter	Winter peak	20 highest hours of H10

Although representative time slices capture typical operating conditions of the system across seasons and during peak conditions, for robust representation of high-VRE systems, they do not capture all aspects of the system variability associated with load and VRE resources, particularly for systems with high shares of renewables. In particular, robust representation of key dynamics related to VRE integration—such as curtailment, firm capacity credit, and the interaction of load and generation resources with storage—requires more resolved (e.g., hourly) chronologies over much longer periods (weeks to a full year).

To address this, ReEDS employs a dedicated VRE module that captures a full 8,760-hour time series of load and renewable resource profiles to characterize VRE operation, the contribution to planning reserve margins, and the interaction with storage. The VRE module is used to determine the seasonal capacity credit for each region/class combination via an hourly load duration curve approximation of effective load-carrying capability (Brown et al. 2020; Frew et al. 2017). As described, the VRE module is interleaved with the previous supply module results, informing the subsequent supply module solve by passing a series of parameters to the supply module, including marginal capacity credits, marginal curtailment rates, and the value of storge.

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2.2.2 Input Assumptions

For load shape and variable renewable resource profile data, ReEDS draws on historical data from a single year to preserve the linkage between weather, load, and VRE resources. In this study, the capacity expansion analysis is conducted using historical load and resource data from 2012.[12] Hourly load data are taken from the Federal Energy Regulatory Commission Form 714 and are depicted in Figure 11, along with the representation in ReEDS time slices. Hourly wind and solar PV profiles are drawn from the NSRDB and the Wind Toolkit databases, as discussed in Section 2.1.

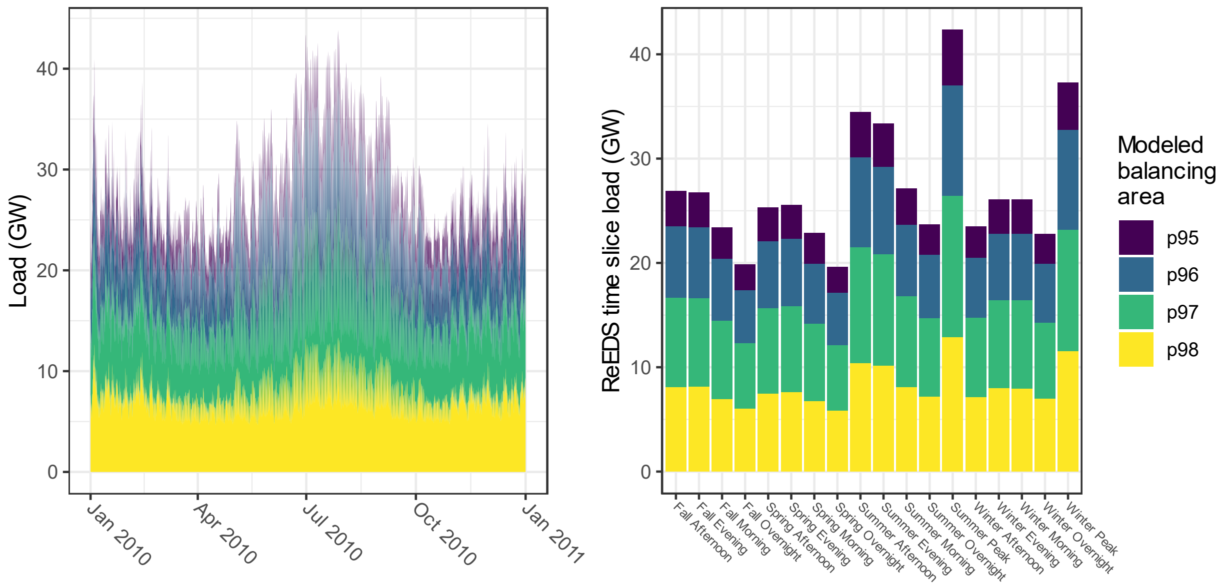

Figure 11. Hourly load data for the four modeled balancing areas in the Carolinas (left) and corresponding load values for each ReEDS time slice (right)

Although ReEDS assumes that the hourly load shape is constant over each year in the analysis, the total load is scaled upward on an annual basis to reflect load growth over time. This study assumes an annual growth rate of 0.6% for load in the Carolinas, based on a previous analysis of load growth for Duke Energy and slightly adjusted upward based on conversations with Duke Energy (Duke Energy 2020a; Electric Power Research Institute 2019). This load growth trajectory is based on estimates from electrification along with reductions due to energy efficiency deployment.

All other regions are assigned regional growth rates corresponding to those in the U.S. Energy Information Administration (EIA) *Annual Energy Outlook* (AEO) 2020. Additional electrification, efficiency and demand response, climate impacts, and other factors can affect not only the load growth rate but also the timing and shape of the load. Although we test a sensitivity

[12] As a sensitivity, we evaluate an operational model using 2018 weather data and load; this is discussed further in Section 2.3.

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using projected electrification load shape changes, more analysis should focus on the magnitude and impact of these changes.

Initial assumptions for the capital costs for investments in new generating capacity are based on the NREL 2020 ATB assumptions, with costs for each technology varying depending on the year of the investment (NREL 2020). For battery technologies, capital cost and performance assumptions are derived from Cole and Frazier (2020). Regional capital costs multipliers—accounting for differences in labor, material costs, and other geographic influences—are applied by technology based on data provided by a report by the EIA/Leidos Engineering (EIA 2016). Fixed and variable operation-and-maintenance costs are also derived from the NREL ATB. Fuel costs are based on projections from the EIA AEO 2020. Figure 12 illustrates key capital and fuel cost inputs over time for the Carolinas as applied in this study.

The model includes a wide range of technologies that can be deployed. Land-based and offshore wind as well as solar PV[13] are modeled with the geographic resolution previously described, using the cost and resource availability from the resource assessment. The model includes other renewable resources (such as hydro, geothermal, concentrating solar power, and biopower) as well as conventional resources (such as nuclear, coal, and natural gas combined-cycle and combustion turbines). Fossil fuel resources have the option to be built with carbon capture and sequestration with a 90% capture rate. ReEDS also models a generic storage technology that has cost and performance parameters similar to lithium-ion batteries, along with pumped hydro storage.

In addition to traditional thermal or renewable generation technologies, ReEDS can invest in firm renewable capacity via renewable energy combustion turbines (RE-CTs). These RE-CTs represent commercial gas turbines that burn renewable fuels. Given uncertainty in the future availability of alternative zero-carbon fuels such as biogas or hydrogen (Ruth et al. 2020), no specific type of fuel is associated with this type of generating facility. Rather, it is assumed that a generic zero-carbon fuel is available, but at relatively high cost $20 per MBtu, which is inclusive of production, delivery, and storage costs. These fuel costs are consistent with projected estimates for the cost of hydrogen produced from electrolyzers by dedicated wind or solar PV (Mahone et al. 2020), carbon-neutral biogas (Hargreaves and Jones 2020), or ethanol or biodiesel fuel.[14]

These turbines have heat rate, operation-and-maintenance costs, and other performance characteristics that are similar to gas turbines in ReEDS. Capital costs for RE-CTs are 20% higher than traditional gas turbines; this premium is slightly higher than the 10% value reported in Ruth et al. (2020) to account for clutching the RE-CTs. Note that ReEDS does not explicitly model the use of curtailed VRE resources for RE-CT fuel production, nor does it capture transportation network requirements for this zero-carbon fuel.

[13] In addition to utility-scale PV, the model includes options for distribution-side utility-scale PV and distributed (rooftop) PV. Rooftop PV adoption levels are taken from a separate consumer adoption model. For more details, see the ReEDS model documentation (Brown et al. 2020).
[14] Note that the version of ReEDS used in this study does not explicitly capture the electricity demands associated with RE-CT fuel production, nor does it capture transportation network requirements.

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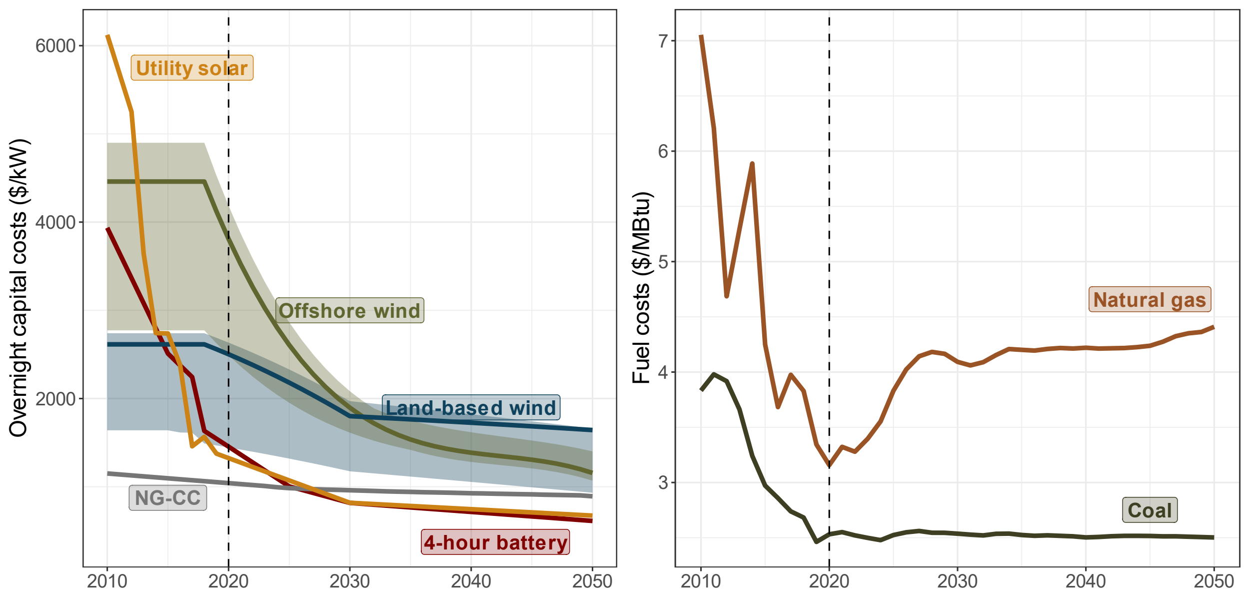

Figure 12. Baseline capital cost (left) and fuel costs (right) assumptions in ReEDS

Capital costs are based on the NREL ATB (2020), and fuel costs are derived from the EIA AEO (2020). For wind resources, the range of values indicates costs across different resource quality regions, with the central line indicating values for the most common resource in the Carolinas.

Duke Energy might be limited in its ability to deploy new natural gas combined-cycle facilities because of constraints in the gas pipeline network. Although a full gas network pipeline representation was outside the scope of this study, we apply a $1.50/MBtu fuel price adder for new natural gas combined-cycle facilities to serve as a proxy for the increased cost of acquiring firm pipeline transport capacity for new facilities. In addition, to capture existing wheeling charges and other costs of electricity trade in the region, we apply a $10/MWh hurdle rate to any electricity transfers between the four Carolina balancing authorities and other balancing authorities.

In modeling the Carolina balancing authorities, ReEDS takes data on the existing generating fleet from the EIA National Energy Modeling System (NEMS) database used in the AEO 2019 (EIA 2019). These data include summer nameplate capacity, location, heat rates, operation-and-maintenance costs, and emissions rates (Brown et al. 2020). Figure 13 presents the 2020 summer nameplate capacity for the Carolinas as used in ReEDS (shown in purple); for reference, a comparison is provided to the capacity of Duke Energy's Carolinas service territory (shown in yellow), based on their 2020 IRP (Duke Energy 2021). Differences in capacity reflect the fact that ReEDS models parts of the Carolinas not included in Duke Energy's territory, including those serviced by Dominion, Santee Cooper, and any municipal power authorities or co-ops. The model also includes information on planned capacity additions, which includes a 1600 MW expansion of the Bad Creek pumped hydro facility in South Carolina, scheduled to be completed by 2035.

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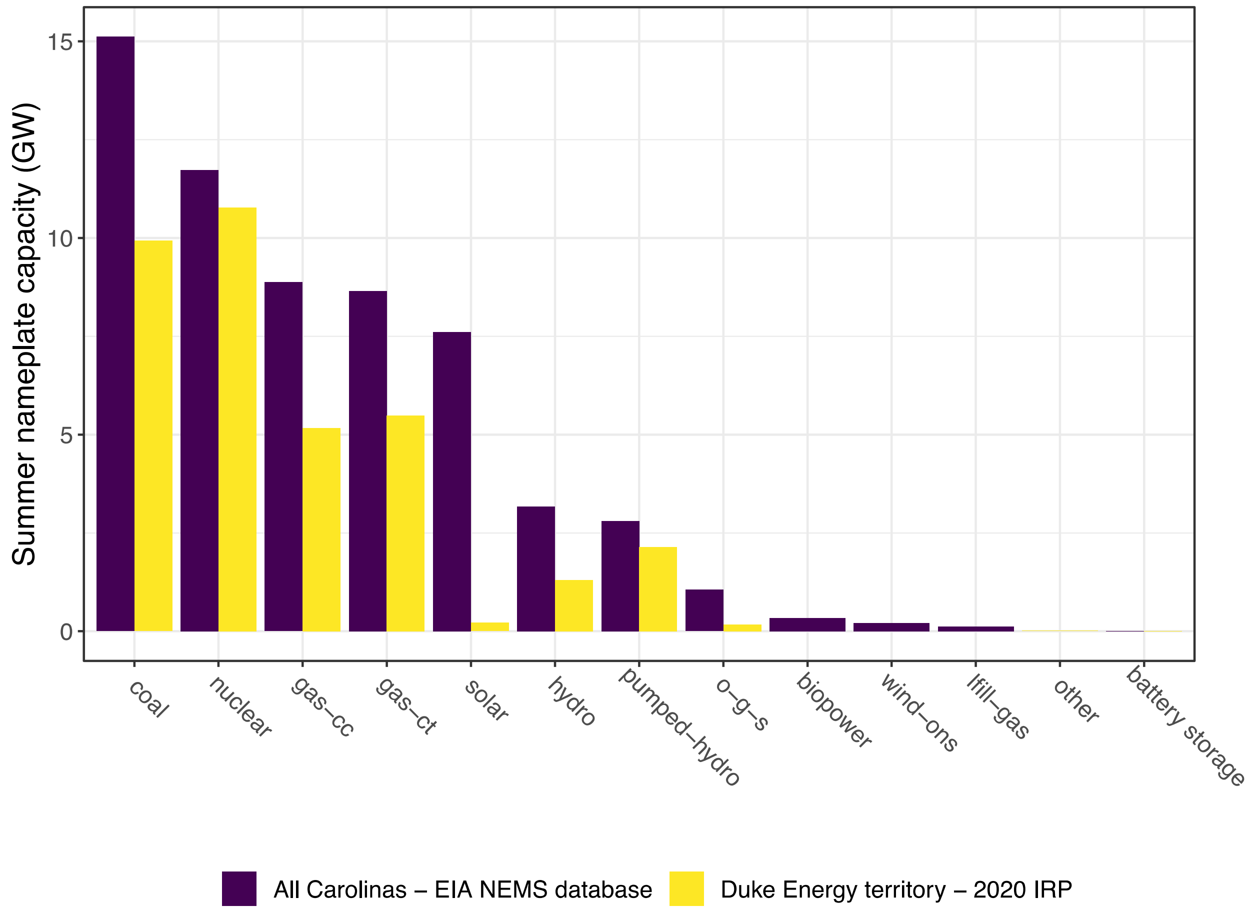

Figure 13. The 2020 installed capacity assumptions for both Carolinas as used in ReEDS for this study

The installed capacity for Duke Energy's footprint is provided for comparison; note that the Carolinas estimate includes capacity from other utilities in the Carolinas, namely, Dominion Energy and Santee Cooper. Values are presented as summer nameplate capacity.

Retirements of capacity in ReEDS are governed primarily by two processes: (1) data on announced retirement dates and (2) technology-specific lifetime limits. For this study, two modifications were made to the plant retirements. First, it was assumed that all nuclear plants in Duke Energy's territory receive license extensions that permit operation up to 80 years and thus are capable of operating through 2050.

Second, the retirement dates for select coal power plants were matched to recent plans for phasing out these units. The assumed retirement dates for Duke Energy's coal units are presented in Table 2. Since this study began, discussions have continued about further accelerating the retirements of several units before 2030, including Roxboro 3 and 4, Mayo, and Cliffside 5. An evaluation of these retirement scenarios is presented in the operational modeling using PLEXOS, and these plants are identified in the table.

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Table 2. Coal Retirement Dates Specified in ReEDS for This Study

Note that this table might not include more recent updates or accelerations to coal retirements planned in the Carolinas; plants with accelerated retirements tested in the accelerated retirement case are identified in the third column.

Boiler Type	Plant Name	Retirement Date in ReEDS	Accelerated Retirement Case
Subcritical	Allen 1	2023	
	Allen 2	2023	
	Allen 3	2023	
	Allen 4	2027	
	Allen 5	2027	
	Roxboro 1	2028	
	Roxboro 2	2028	
	Cliffside 5	2032	2030
	Roxboro 3	2033	2030
	Roxboro 4	2033	2030
	Marshall 1	2034	
	Marshall 2	2034	
	Mayo 1	2035	2030
Supercritical	Marshall 3	2034	
	Marshall 4	2034	
	Belews Creek 1	2038	
	Belews Creek 2	2038	
	Cliffside 6	2048	

2.2.3 Description of Scenarios

The ReEDS analysis focuses on two major scenarios:

1. **Base case**: a reference case with no emissions constraints in the Carolinas
2. **Policy case**: includes two emissions targets for electricity generation in North Carolina: a 70% CO_2 reduction in annual emissions (relative to 2005 levels) starting in 2030, equivalent to an annual target of 23.8 million metric tons (MMT) CO_2; and a zero-carbon electricity system by 2050.

The base case is not intended to be a prediction of the future in the absence of any new policies; rather, it serves as a benchmark from which to evaluate how carbon emissions limits introduced in the policy case impact the evolution of the system. Because most of Duke Energy's generation capacity and load is in North Carolina and because the state of North Carolina has proposed a zero-carbon target for 2050, we focus on an emissions constraint only for North Carolina, not both Carolinas; however, throughout this report, we present results for both Carolinas.

For the policy case, we assume that the CO_2 emissions constraint declines linearly from 2030 to 2050. In addition, we assume that no new fossil-fueled generation can be built in the Carolinas after 2035, which is the last year considered in Duke Energy's most recent IRP.

In the core policy case, although fossil fuel resources *cannot* be used to meet energy requirements by 2050, any remaining, non-retired fossil fuel capacity can be used to meet planning reserve requirements. This assumption implies that fossil fuel capacity could be maintained to supply emergency or backup capacity under periods of system stress. Because the

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treatment of reserves is not explicitly addressed in the North Carolina target, we evaluate an additional case to the core policy scenario in which all fossil-fueled plants in the Carolinas must be retired by 2050—namely, by 2050 fossil fuel cannot provide energy, operating, or planning reserves.

In addition to these main cases, we run a series of sensitivities related to uncertainty in key ReEDS modeling assumptions. These sensitivities can be grouped thematically into one of three categories:

- **Cost sensitivities:** We explore the effect of higher solar PV/storage costs, higher solar PV/storage costs paired with lower than anticipated natural gas costs, and lower land-based wind costs, based on high and low cases from the EIA AEO and the NREL ATB (EIA 2020; NREL 2020).
- **Wind sensitivities:** We test different wind resource assessments based on more limited land-based wind development opportunities and the availability of a more advanced turbine (see Section 2.1 for details).
- **Operational sensitivities:** We evaluate the impact of imposing similar emissions reduction constraints on the rest of the Eastern Interconnection, relaxing the requirement that Duke Energy procure all firm capacity needs from within the Carolinas, and considering high levels of electrification with additional load flexibility based on analysis in the NREL Electrification Futures Study (Murphy et al. 2021).

Table 3 summarizes the combination of scenarios and sensitivities analysis for the investment pathway results in ReEDS.

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Table 3. Details on ReEDS Scenarios and Sensitivities for the Duke Energy Carbon-Free Integration Study

The production cost modeling focuses on specific buildouts from the main base and policy scenarios; for more information on the production cost model scenarios see Section 2.3.1.

	Base (No emissions constraints in NC)	Policy (70% CO_2 reduction in NC by 2030 + net-zero electricity in NC by 2050)
Main cases	Standard modeling assumptions	
	--	All fossil fuels must retire in the Carolinas in 2050.
Cost sensitivities	Low-cost wind High-cost solar PV/storage High-cost solar PV/storage + low-cost natural gas	
Wind availability sensitivities	Limited access (excludes radar line-of-site) State-of-the-art turbine design	
Operational sensitivities	Eastern Interconnection has CO_2 targets (70% in 2030, net zero in 2050) Duke Energy is able to secure firm capacity outside of the Carolinas. High-electrification case	

2.3 Production Cost Modeling

The third analysis component of this study included using production cost modeling to simulate the operation of the ReEDS system buildouts. Although the capacity expansion models primarily focus on questions of which resources are built to meet system requirements and policy constraints, production cost modeling can be used to test those buildouts at more granular temporal resolutions and with greater operational detail. Table 4 presents some typical modeling distinctions between the capacity expansion and production cost models used in this study. In this study, the production cost modeling runs evaluate the performance of the ReEDS buildouts and provide additional insight into opportunities or challenges not apparent from the capacity expansion modeling results.

The production cost modeling phase of this study involves running a unit commitment/economic dispatch of not only Duke Energy's service territories but also the interconnected power system operators in the Eastern Interconnection. The unit commitment/economic dispatch model is a mixed-integer linear program that minimizes the total cost of production. The model is run at hourly resolution and includes detailed constraints on seasonal generator capacity, ramp rates, minimum loading levels, minimum start and shut times, operating reserve requirements, and transmission constraints, among other system parameters. Transmission is solved using DC optimal power flow, a linearized approximation of AC power without the reactive power component. For this study, NREL used PLEXOS, a commercial-grade production cost modeling tool developed by Energy Exemplar.

There are several objectives of the production cost modeling in this study:

- Better understand select operational dynamics of the ReEDS buildouts—such as VRE curtailment and generator ramping—when modeling with additional temporal/spatial resolution.
- Identify challenges not identified through the more aggregate representation in ReEDS, such as transmission congestion and unserved loads.
- Provide refined estimates of the economic costs of operating the system.

Note that this study does not include contingency analysis or the evaluation of voltage or frequency stability using AC power flow simulations. It is intended to inform—but not replace—future transmission and interconnection studies and the IRP process.

Table 4. Comparison Between Capacity Expansion and Operational Modeling

The operational modeling overview includes descriptions of both the zonal and nodal models.

	Capacity Expansion (ReEDS)	Operational Modeling (PLEXOS)	
Model scope/purpose	Find the *least-cost* technology mix to meet the power system requirements over decades.	*Simulate* the detailed operations of the power system using unit commitment and economic dispatch.	
Temporal resolution	18 representative time slices	Chronological hourly dispatch	
Generator parameters	Average parameters assumed by generator type and vintage	Full heat rates, operational constraints (e.g., minimum generation levels, ramp rates) by plant	
Dispatch	Dispatch according to time slices	Hourly unit commitment and economic dispatch	
Spatial resolution	4 modeled balancing areas in the Carolinas	4 modeled balancing areas in the Carolinas (zonal model)	Nodal representation (nodal model)
Transmission	Between modeled balancing areas	Between modeled balancing areas (zonal model)	Full transmission system representation (nodal model)

2.3.1 Overview of Scenarios Analyzed

Two distinct PLEXOS models are employed: a "nodal" model, which includes a full nodal transmission representation for the entire Eastern Interconnection, and a "zonal" model, which matches the zonal representation used in ReEDS. We employ the nodal model to test the more near-term policy cases from ReEDS, namely, where Duke Energy achieves the 70% CO_2 reduction in North Carolina in 2030. In contrast, we employ a zonal model to evaluate operations of the net-zero power system in 2050 because the transmission system is likely to undergo more

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significant changes leading up to 2050. A base case representing 2024 operations is used to benchmark the results for both the nodal and zonal cases. Both models are simulated at an hourly resolution for 1 year (8,760 hours).

Because of the large computational requirement of the production cost models in this study, NREL identified a subset of the ReEDS buildouts to test the operational performance in PLEXOS. Table 5 presents the set of scenarios tested with production cost modeling. For the nodal model, we then primarily focus on the 2030 policy case, with additional sensitivities on the coal retirement schedule. We also test the 2036 ReEDS buildout with load and resource profiles from 2018, which captures an extended cold period during the winter.

Table 5. ReEDS Cases Tested with Either Nodal or Zonal Production Cost Modeling

Model Type	Model Name	ReEDS Buildout Year	Policy Constraint?	Weather Year
Nodal model	Duke 2024	2024	N	2012
	Duke 2030	2030	Y	2012
	Duke 2030 coal retirements	2030 + accelerated coal retirements[a]	Y	2012
	Duke 2036 extended cold snap	2036	Y	2018
Zonal model	Carolinas 2024	2024	N	2012
	Carolinas 2050	2050	Y	2012

[a] See Table 2 for details on which coal plants have accelerated retirements in this scenario.

The following two sections provide additional details on the assumptions of the nodal and zonal PLEXOS models.

2.3.2 Description of Nodal PLEXOS Database

The nodal PLEXOS database provides the full representation of all nodes and transmission lines in the Eastern Interconnection. The base model was developed from a PLEXOS database built as part of NREL's North American Renewable Integration Study (Brinkman et al. 2021). NREL worked closely with Duke Energy to validate and update the base nodal database with information specific to Duke Energy's service territory, including adding details on the winter and summer capacity limits for thermal units.

Figure 14 shows the geographic layout of the base nodal model developed from the North American Renewable Integration Study. The database consists of 78,463 buses (2,944 buses for Duke Energy's service territory), 71,328 lines (3,176 lines for Duke Energy), and 27,901 transformers (890 transformer for Duke Energy) (Brinkman et al. 2021).

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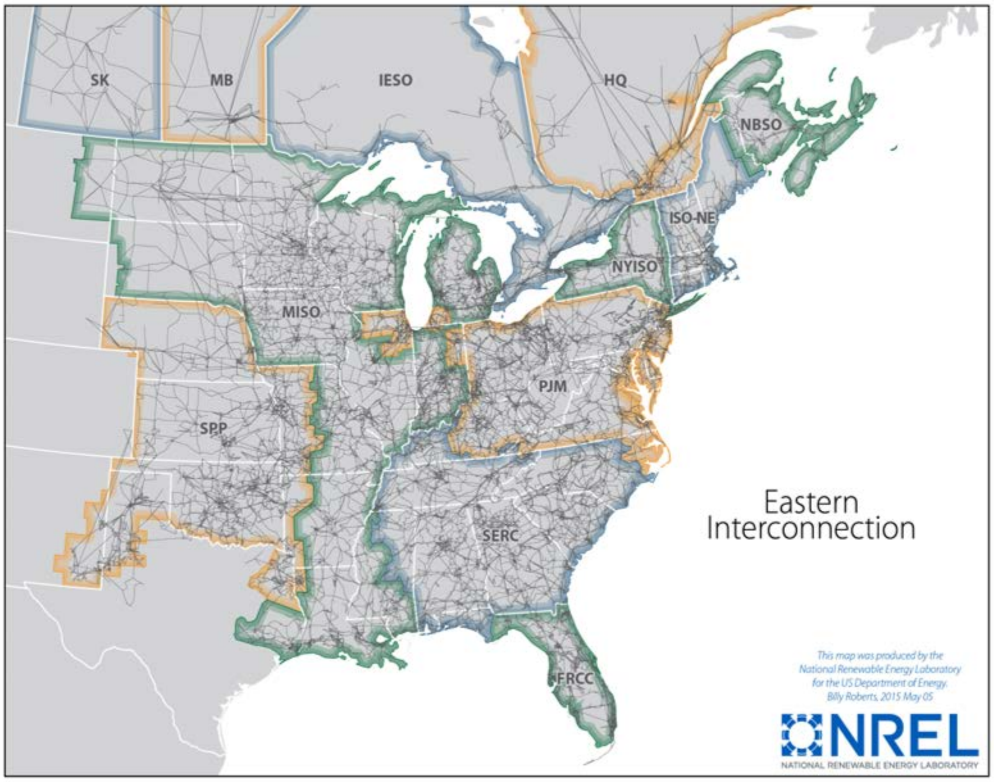

Figure 14. Map depicting the nodal PLEXOS model representing the entire Eastern Interconnection, including all nodes and transmission lines

We run a single, hourly resolution model that represents a modified day-ahead dispatch with perfect load and resource forecasts. The optimization is solved in steps of a single day, with an additional day "look-ahead" window for each step. Although perfect forecasts of load, wind, and solar PV are used for the dispatch, the model uses historical forecast errors to determine the operating reserve requirements in each period, and it schedules reserve provision by generators to meet those requirements. The development of the reserve requirements for the nodal model was done in consultation with Duke Energy. To simulate friction in electricity trade and to match the assumptions used in ReEDS, a hurdle rate of $10/MWh was applied to any power transferred between Duke Energy and neighboring regions.

To update the 2024 database with the ReEDS buildout for Duke Energy's service territory in the policy cases, we add new installed capacity—primarily utility-scale and distributed solar PV, land-based wind, and battery storage, but also some natural gas capacity—and retired any coal units with retirement dates occurring before the relevant scenario. Figure 15 illustrates the timeline for new capacity and retiring capacity in each scenario.

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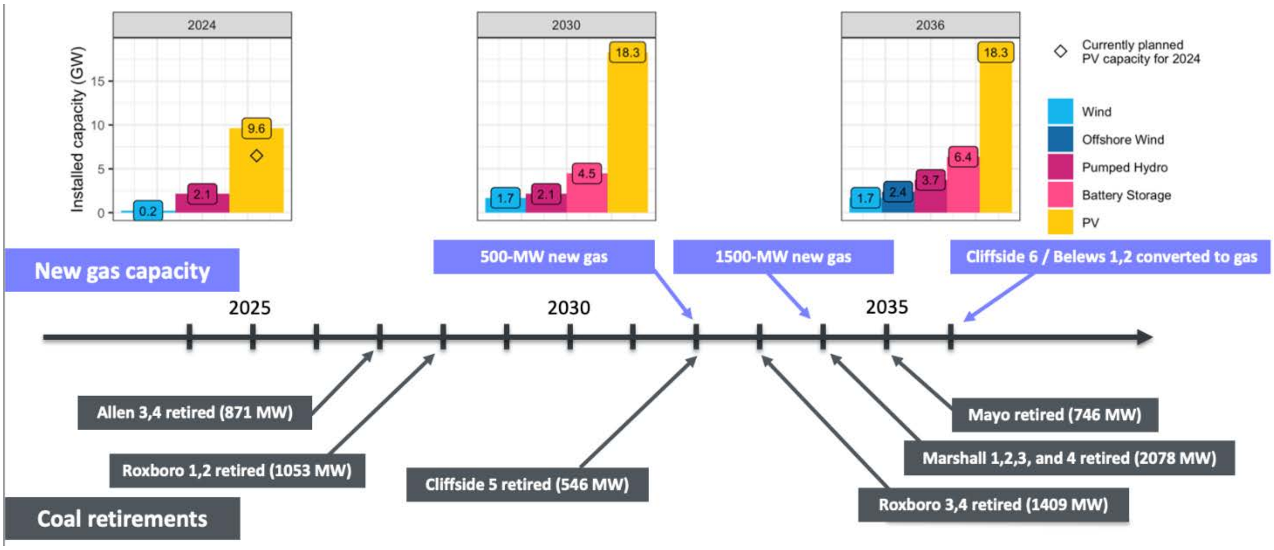

Figure 15. Timeline depicting the change in clean generation capacity PV as well as new gas generation capacity and coal retirements across the 2024, 2030, and 2036 nodal PLEXOS models

To site new utility-scale wind and solar PV plants, we first identify the installed capacity targets for each technology for the Carolinas based on the ReEDS policy case. For land-based wind, the capacity targets are applied directly from each ReEDS balancing area; for offshore wind, NREL worked with Duke Energy to identify potential nodes for interconnecting those new resources.

For solar PV, we first develop a target for the entire Carolinas based on the ReEDS trajectory, and then we allocate builds from that target to the service territories in the region. For the 2030 case, we assume that 75% of the new solar PV by 2030 (approximately 9 GW) is placed on Duke Energy's system, and the remaining 25% (approximately 3 GW) is assigned to non-Duke Energy areas of South Carolina. Additional solar PV buildout from 2030 to 2036 is then assigned to the non-Duke Energy areas of South Carolina. The 2036 buildout also includes new solar PV built in Dominion Energy's territory.

From those area-based capacity targets, we then draw on data from the reV model used in the resource assessment (see Section 2.1 for details) to identify the sites with the lowest estimated LCOE, based on wind and solar PV resource and distance from the nearest interconnection point. Interconnection nodes are identified based on the shortest straight-line distance to the nearest node, excluding nodes exceeding 500 kV. The cheapest sites are selected as built until the capacity targets from ReEDS are met. Additional filters are used to constrain which sites are built. For example, sites with long spur lines (longer than 30 km) are removed, with the next least-cost site being taken. Nodes connected to 115-kV lines or below are assumed to be able to accept a maximum of up to 20 MW of new solar PV, whereas higher-voltage lines can accommodate up to 150 MW. NREL worked closely with Duke Energy to verify the nodal site placement for wind and solar PV. Figure 16 shows the placement of the new wind and solar PV resources in the model.

For distributed PV resources, new capacity in ReEDS is taken from the NREL dGen™ model, which simulates consumer adoption of rooftop PV based on solar PV resource, utility rate structures, and adoption behavior. The new distributed PV capacity is then allocated across

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nodes in the Carolinas in accordance with load participation factors. Unlike utility-scale solar PV and wind, distributed PV cannot be curtailed in the optimization.

Finally, the 2030 and 2036 nodal models also include new energy storage capacity builds, which include both 2-hour- and 4-hour-duration batteries. To site new storage, we first assume that 65% of the new battery storage is placed at retired or soon-to-be-retired coal power plants so that these units can provide voltage support after the retirements. The remainder is assumed to be paired with new, utility-scale solar PV. The resulting ratio of storage power capacity to solar PV capacity is approximately 14%, which falls within the estimated range of optimal storage-to-solar PV power capacity from recent work evaluating increased solar PV integration in North Carolina (Virguez, Wang, and Patiño-Echeverri 2021). Figure 17 illustrates the location of new storage capacity for the 2030 nodal model.

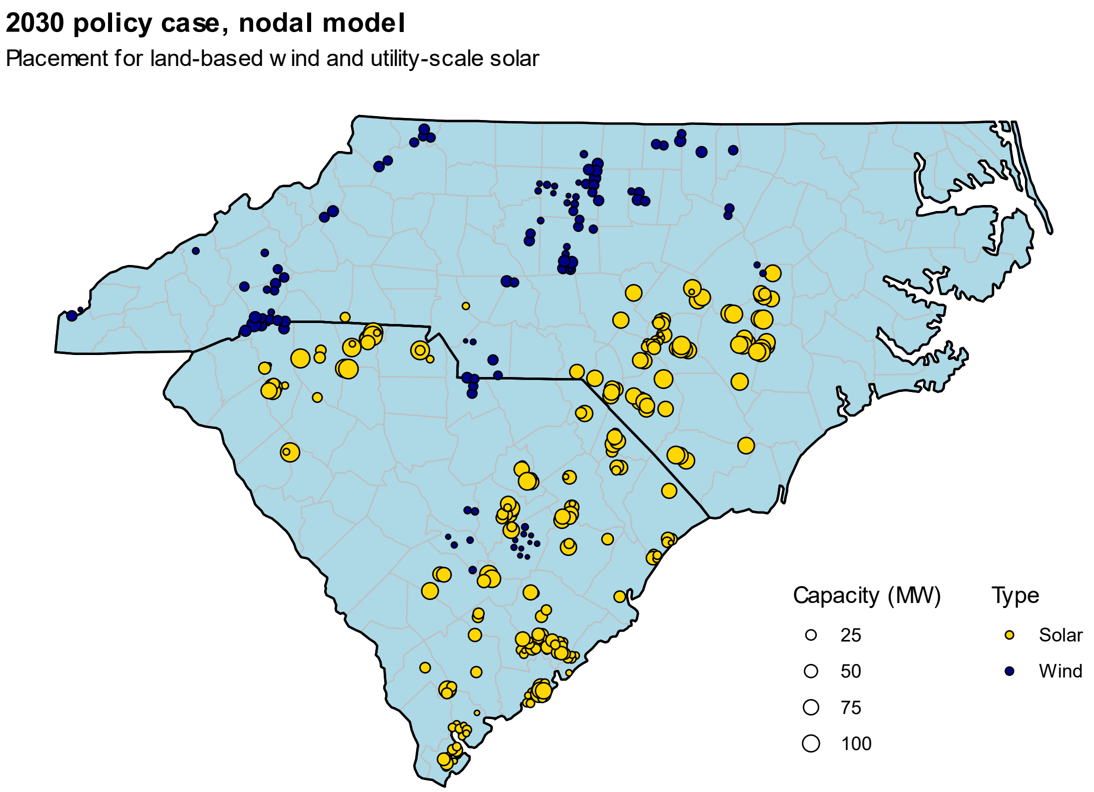

Figure 16. Map showing the placement of new utility-scale solar PV and wind resources to build the 2030 nodal PLEXOS model

New wind and solar PV capacity targets are taken from the 2030 ReEDS policy case buildout.

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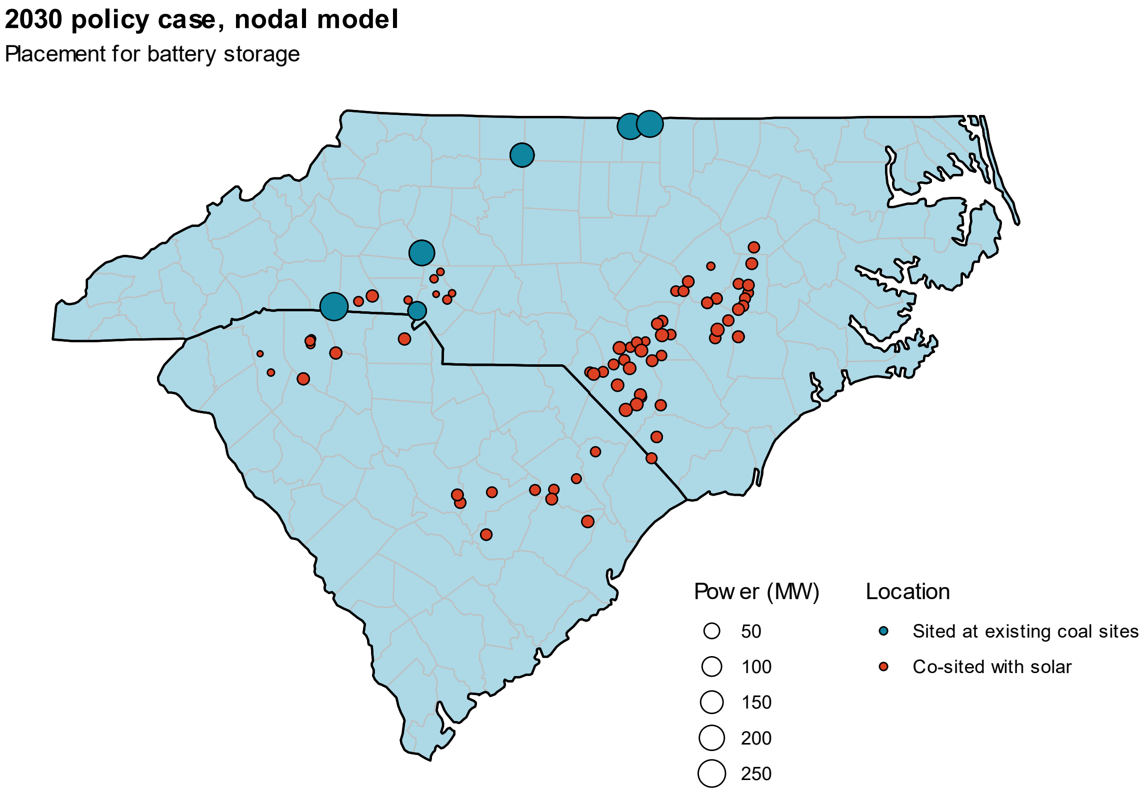

Figure 17. Map showing the placement of new battery in the 2030 nodal PLEXOS model

Storage is categorized by its placement at retired or soon-to-be-retired coal power plants or as colocated with solar PV.

Three of the four nodal PLEXOS runs are evaluated using the same hourly load and weather data from 2012 to inform the investment decisions in the capacity expansion modeling, described in Section 2.2.2. The exception is the 2036 buildout tested with the extended cold snap, which uses 2018 weather and load; in this case, we use load data provided by Duke Energy and supplemented by data from Federal Energy Regulatory Commission Form 714 for the neighboring regions. Wind and solar for the 2018 weather profile case are taken from separate reV runs based on NSRDB and WIND Toolkit data.

2.3.3 Description of Zonal PLEXOS Runs

In addition to the nodal PLEXOS model for 2030, we run a zonal PLEXOS model for the 2050 net-zero emissions electricity sector build. We employ a zonal model for this case because the ReEDS buildout supporting zero-carbon emissions is likely to require substantial additional transmission grid upgrades beyond the current network topology. Because a full suite of optimal transmission network expansion studies is beyond the scope of this current project, we focus on a simplified, zonal model that focuses on the operational characteristics of the zero-carbon system.

To develop the zonal 2050 model, we use a ReEDS-to-PLEXOS translation tool developed at NREL that generates a PLEXOS database from a ReEDS solution. The tool matches ReEDS installed capacity, balancing area representation, operating reserve representation, projected fuel prices, and interzone transmission buildout, but it provides additional temporal and spatial

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modeling detail for production cost modeling. For example, installed capacity in each ReEDS balancing area is broken down into individual generators based on typical generator size, and generators are assigned ramp rates, minimum stable levels, and other parameters based on characteristics of each technology class. The translator uses the same input wind, solar PV, and load profile time-series data as ReEDS, but now with full hourly resolution for the production cost model. Additional details on the ReEDS-to-PLEXOS linkage can be found in the ReEDS model documentation (Brown et al. 2020) and in Cowiestoll and Frazier (2022).

Figure 18 illustrates the spatial resolution of the zonal PLEXOS model. As in ReEDS, load must be served within each balancing area, with the ability to transmit power via transmission (see Figure 9 for an illustration of the zonal transmission network). Reserve requirements are held at the regional level, meaning that reserves can be shared across modeled balancing areas within a region but cannot be traded across regions; in this instance, the Carolinas are modeled as one reserve region (VACAR).

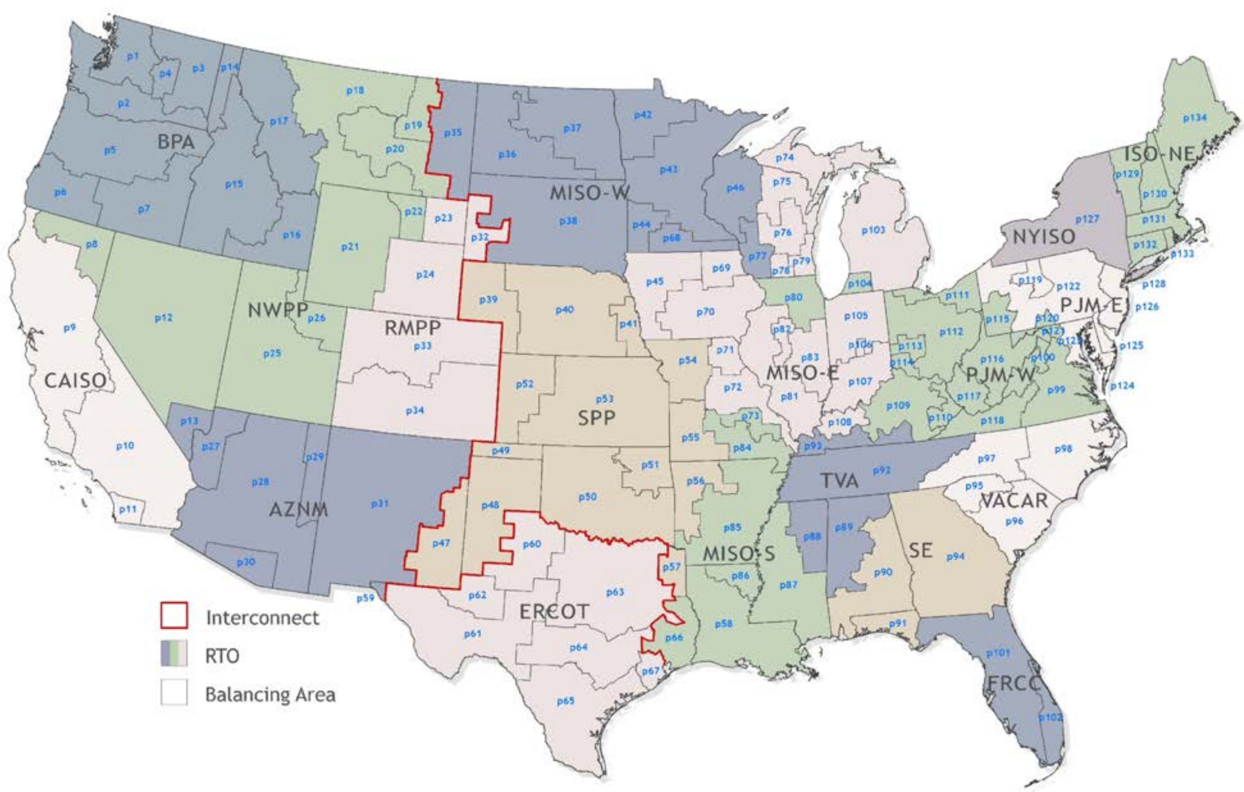

Figure 18. Depiction of the geographic resolution used in the zonal PLEXOS model

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3 Investment Pathway Results

In this section, we present the results from the ReEDS analysis on investment pathways for the Carolinas. Sections 3.1and 3.2 present the capacity buildouts, Section 3.3 estimates emissions and system costs for the main cases, and Section 3.4 summarizes findings from the sensitivity analysis.

3.1 Capacity Buildouts

Figure 19 presents the installed generating capacity from ReEDS for the Carolinas for the main scenarios: base, policy, and policy with the requirement of no fossil in the Carolinas in 2050 (see Section 2.2.3 for details on these scenarios). Results are shown for 2020 to reflect a benchmark against the current system; 2030 to reflect the system after the intermediate, 70% target in the policy case; and 2050 to reflect the zero-carbon emissions system. Table 6 provides the installed capacity numbers for select technologies in the Carolinas.

In the base case and without any carbon emissions policy, the Carolinas adds slightly more than 20 GW of new installed capacity between 2020 and 2030. Most of this new capacity comprises solar PV, but new wind and storage are added as well. The policy cases are similar to the base case, with slight increases in total installed capacity (~6 GW), again primarily from solar PV.

The results show that in all cases, the Carolinas rely on increased capacity from solar PV, land-based wind and offshore wind, and battery storage to meet its electricity needs. The 2030 emissions constraint is met through a mix of existing nuclear and new land-based wind and solar PV capacity, with the policy constraint primarily encouraging slightly more solar PV development than the reference case. The similarity between the base and policy cases indicates that under the ReEDS cost assumptions, the base case gets close to achieving the 2030 carbon emissions policy target. This is driven by the low cost renewable energy technologies—in particular, solar PV—which are already the least-cost technologies for new capacity even without supporting policy and which are anticipated to continue to decline in cost.

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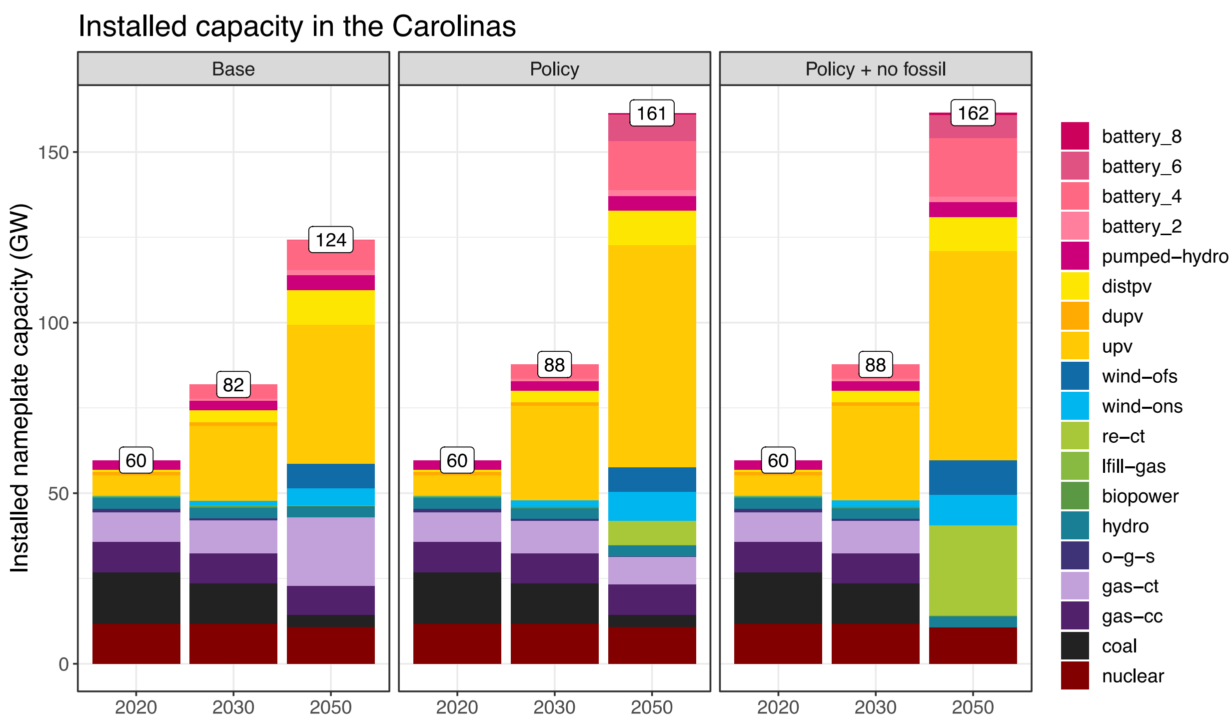

Figure 19. Installed capacity results by technology for the Carolinas for the main cases (base, policy, and policy with requirement for no fossil in 2050)

Table 6. Installed Capacity (GW) for Select Technologies by Year and Scenario

Year	Scenario	Solar PV	Land-Based Wind	Offshore Wind	Natural Gas	RE-CT	Batteries	Thermal Capacity Retirements[a] (Cumulative)
2020	Base	7.6	0.21		18		0.01	0.7
	Policy	7.6	0.21		18		0.01	0.7
	Policy + no fossil	7.6	0.21		18		0.01	0.7
2030	Base	26	1.5		18		4.8	4.7
	Policy	32	1.9		18		4.8	4.7
	Policy + no fossil	32	1.9		18		4.8	4.7
2050	Base	51	5.1	7.2	29		10	19
	Policy	75	8.5	7.2	17	7	24	19
	Policy + no fossil	71	8.9	10		27	26	40

[a] Includes all fossil thermal technologies (coal, natural gas combined-cycle or combustion turbine, and oil/gas steam turbines), nuclear, and biopower-based generation.

Looking to 2050, the base case adds an additional 40 GW of installed capacity. New additions relative to 2030 include solar PV (25 GW), natural gas (11 GW), offshore wind (7 GW), land-based wind (4 GW), and battery storage (6 GW). To comply with the 2050 zero-carbon target in the policy cases, the model builds almost 40 GW of additional installed capacity relative to the

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base case. The additional capacity is supplied by a mix of resources, including solar PV (another 25 GW of additional capacity beyond the base case), land-based wind (3 GW of additional capacity), and battery storage (14 GW of additional capacity). Note that the model also includes an additional 1.6 GW of pumped hydro storage based on the planned expansion at Bad Creek. In the policy case, 11 GW of natural gas are retired in the baseline retirements in the reference case, and the policy + no-fossil case forces all coal and natural gas units to retire.

Figure 20 shows the cumulative new capacity builds in the Carolinas through 2050. The 2030 emissions target not only results in somewhat accelerated solar PV deployment but also slightly reduces the amount of new natural gas capacity build by the model. In all scenarios, land-based wind builds begin in the 2020s, whereas offshore wind builds start in the following decade. The linear emissions reduction requirement encourages RE-CT investments starting in the 2040s, with substantial additional investments in this technology in by 2050 if all fossil-fueled generation in the Carolinas is required to retire.

Figure 21 depicts the average annual build rate of the cumulative new builds starting in 2020; the plot illustrates spikes in the build rate to accommodate the 2030 and 2050 targets in the policy cases. In particular, the 2050 jump reflects the need for more capacity to reduce the last tons of emissions from the system. Although ReEDS pushes many of these builds to 2048–2050, the model does not include growth constraints that would account for supply chain limitations, construction constraints, or other factors constraining the speed at which deployment could occur. Accounting for these considerations would likely incentivize earlier capacity investments to reduce bottlenecks and logistics constraints.

From 2020 to 2050, the average annual new capacity of each scenario is 3.2 GW/year for the base scenario and 4.5 GW/year and 5 GW/year for the policy and policy + no-fossil scenarios, respectively. This includes deploying approximately 60–70 GW of utility solar PV in the Carolinas, equivalent to approximately 2.2–2.7 GW of new PV capacity added annually from 2023 to 2050. This annual deployment rate is four to five times larger than Duke Energy’s annual average solar PV capacity additions in the Carolinas since 2014 (0.5 GW/year) and two to three times larger than the estimate for the solar PV interconnection limit in Duke Energy’s 2020 IRP (0.9 GW/year) (Duke Energy 2021).

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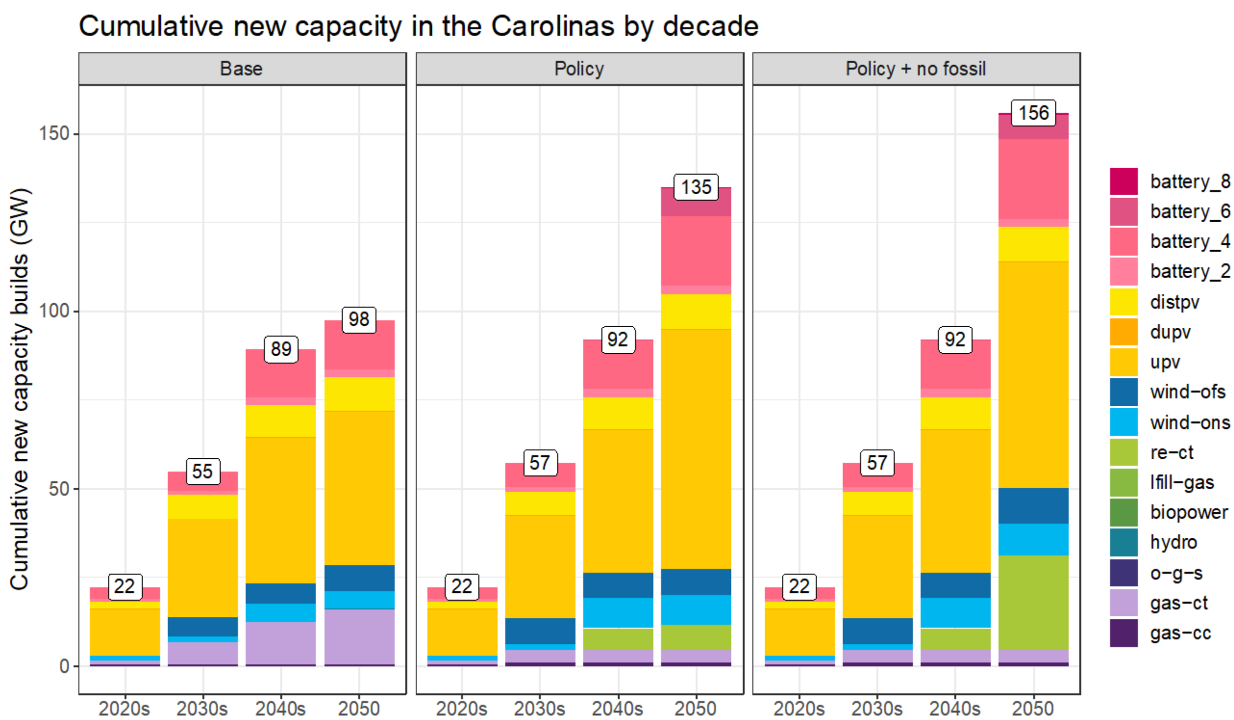

Figure 20. Cumulative new capacity builds by decade for the Carolinas

Note that 2050 includes only that year because that was the last year of analysis.

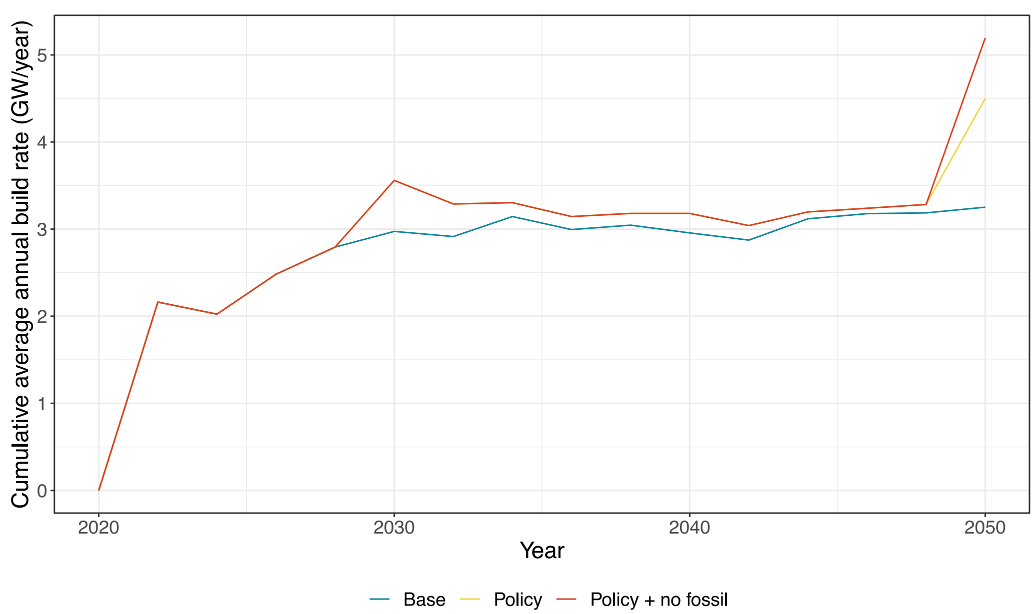

Figure 21. Average annual build rate for new capacity by scenario

Calculated using the cumulative new capacity relative to 2020 divided by the years elapsed since 2020.

In both policy scenarios, the model relies on RE-CTs to supply firm capacity needs. These RE-CTs represent combustion turbines that are designed to use zero-carbon fuels, but the services they are providing could be met with a variety of zero-carbon, low-capital-cost technologies. The

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key characteristics of this technology are that it is capable of providing firm capacity service, it is available to operate at critical time periods when the availability of wind and solar PV output is low or when shorter-duration storage resources are depleted, and that it is economic to operate at relatively low capacity factors on an annual basis. Requiring all fossil fuels to retire increases the amount of RE-CTs built, primarily to meet planning reserve requirements and to reduce reliance on imports.

The no-fossil requirement also increases the amount of offshore wind deployed by the model. Although the increase is small relative to the base and policy cases—3 GW more than the 7 GW installed in the other cases—this increase reflects the advantages of the offshore wind profile relative to solar PV and land-based wind. Figure 22 partially reflects this advantage, demonstrating that offshore wind profiles tend to have higher capacity factors, are more consistent than land-based wind, and are available at night, when there is no solar PV generation. In some instances offshore wind also provides higher output than land-based wind during the winter. The figure also highlights how both wind types and solar PV are relatively complementary, indicating the value of the diverse set of resources deployed by ReEDS for reducing carbon emissions while meeting planning and operational requirements.

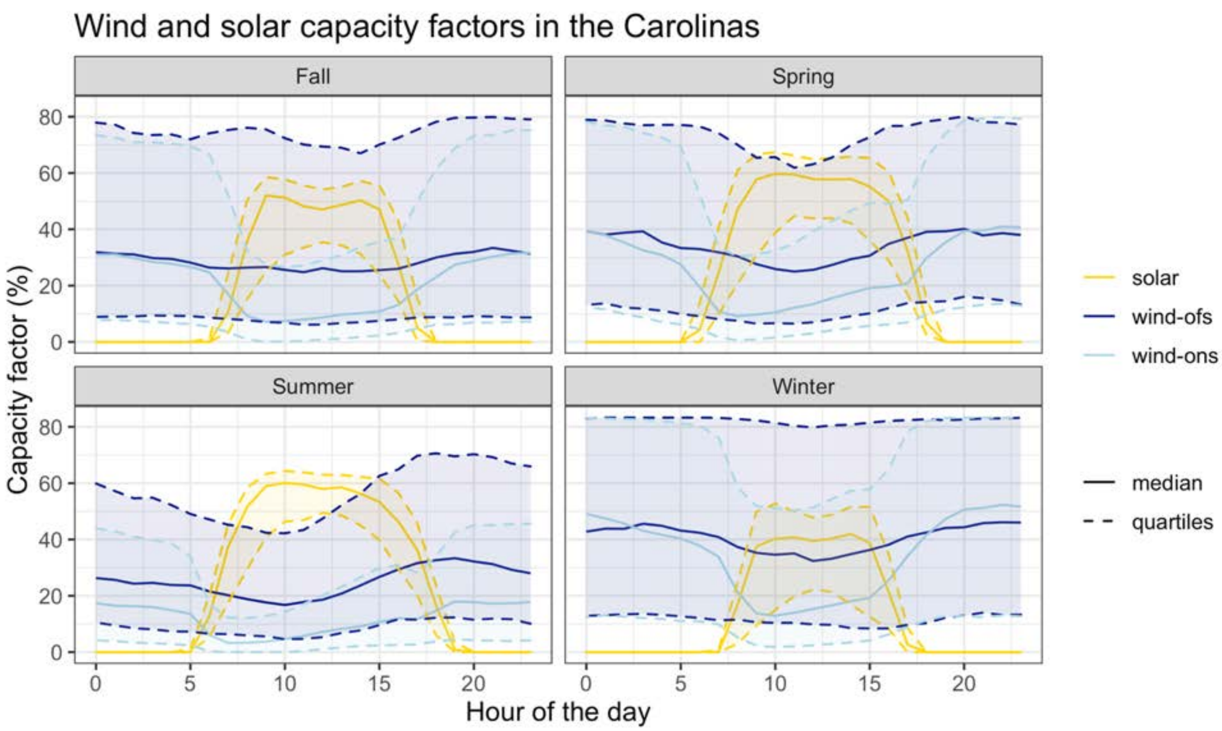

Figure 22. Solar PV, offshore wind, and land-based wind profiles for the Carolinas by season

The solid lines represent the median capacity factor values across all sites identified in the resource assessment, and the dashed lines indicate the quartiles of the data (upper and lower 25%).

Figure 23 illustrates the cumulative changes to firm capacity in the Carolinas, or the amount of capacity that contributes to meeting the system's planning reserve margin. Wind and solar PV resources are assigned seasonal capacity credits based on hourly generation profiles and load data, as discussed in Section 2.2.1. The figure highlights the differences in the resources used to meet the system's needs in summer and winter. During the summer months, peak load tends to

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occur in the late afternoon or early evening, meaning that solar PV, in addition to the non-VRE and storage resources, can still contribute to meeting this requirement. In contrast, the winter peak in the Carolinas occurs in the early morning, when there is typically little to no available solar PV. During this time, additional firm capacity is provided by land-based and offshore wind. In both seasons, the system primarily relies on a combination of battery storage and RE-CTs to provide firm capacity to replace that formerly provided by coal and natural gas units.

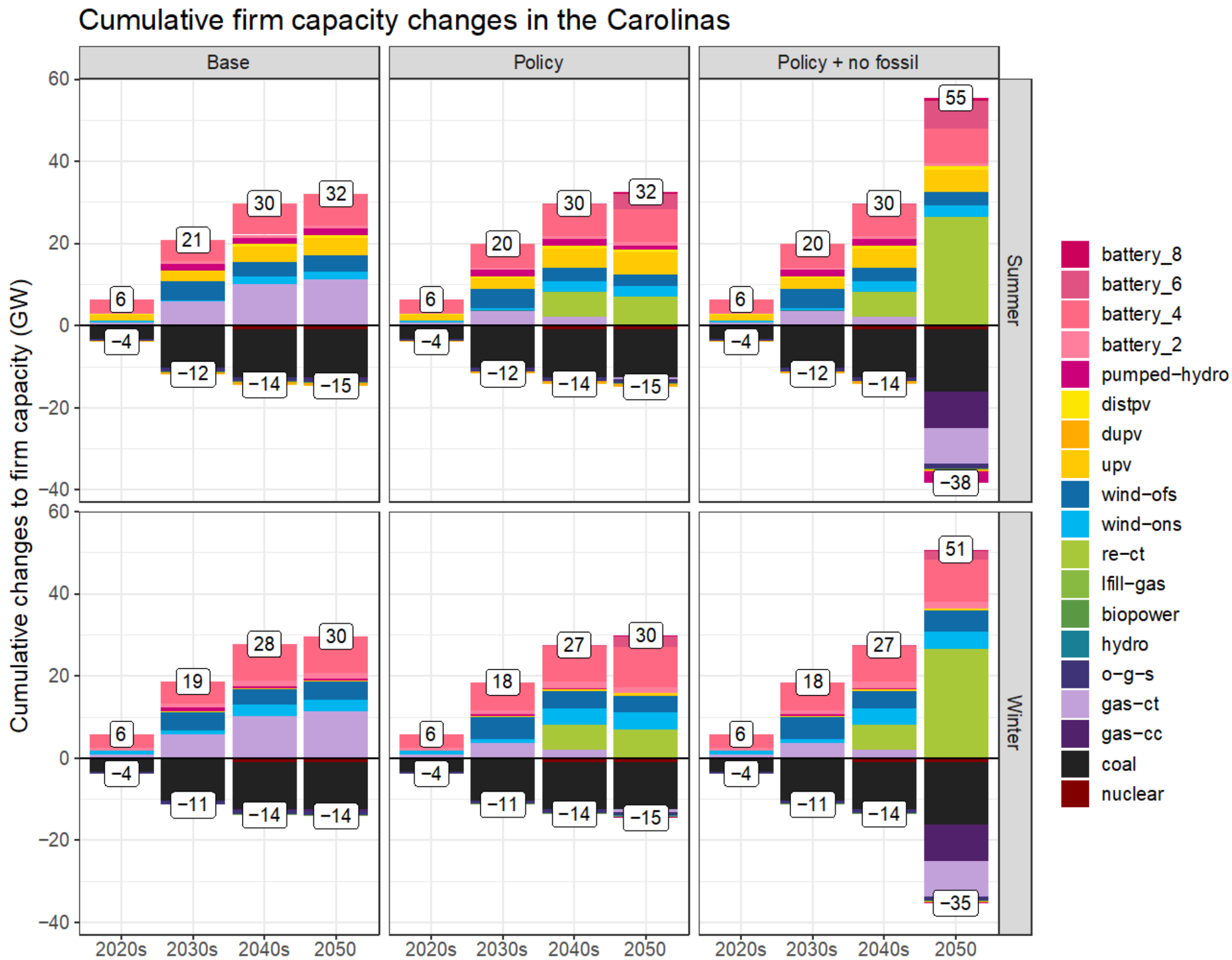

Figure 23. Cumulative firm capacity changes, including retirements (negative values) and new capacity builds (positive values)

The firm capacity of VRE and storage is determined by ReEDS calculations of capacity credit (see methods in Section 2.2.1) and is presented by season (summer, winter). Differences to firm capacity are measured relative to installed capacity in 2020 and are summarized by decade, with values accumulating across each decade.

3.2 Transmission Investments

Changes to the installed generating capacity mix for meeting both the 70% and net-zero targets are supported by increased investments in transmission capacity to transfer power within the Carolinas and to support increased interchanges with Duke Energy's neighbors. Figure 24 depicts the cumulative new investments in transmission capacity between the ReEDS balancing areas in 2030 and 2030 under the base and policy scenarios. In 2030, the policy cases result in

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2.8 GW of additional transmission capacity, whereas the 2050 case yields nearly 12 GW of expanded capacity. Importantly, the base case also results in significant new transmission in both 2030 (1.6 GW) and 2050 (7.2 GW), reflecting the value of this asset for the system regardless of the policy trajectory.

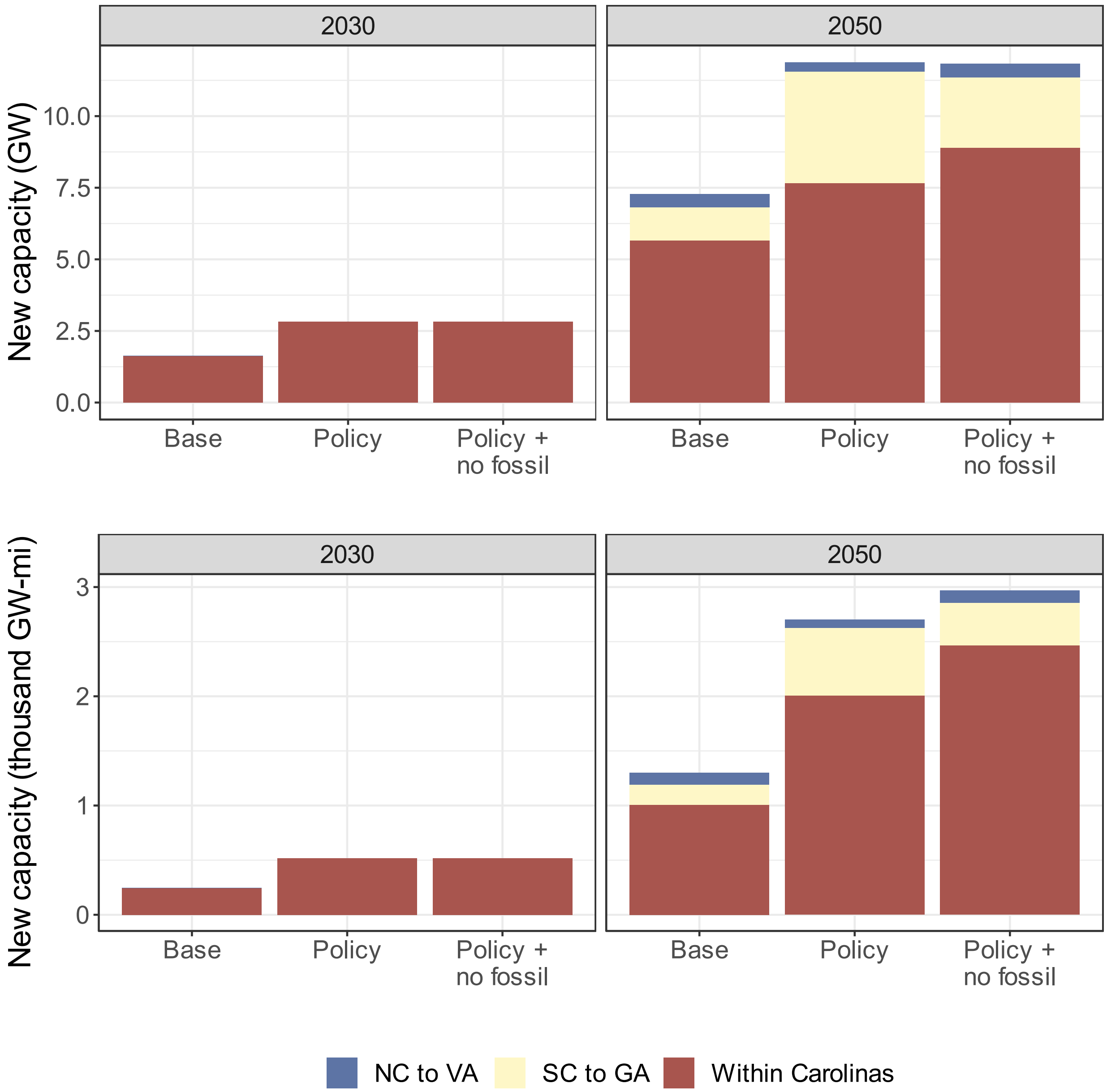

Figure 24. Cumulative new transmission investments (GW and GW-mi) between the ReEDS balancing areas in 2030 and 2050 for the three core scenarios

ReEDS also represents existing transmission to Tennessee, but no new transmission is built on that route by the model.

Figure 25 depicts the location of the interface transmission investments by the ReEDS model. By 2030, all cases result in increased transmission capacity between the ReEDS balancing areas covering western South Carolina and western North Carolina, eastern North Carolina and

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Virginia, and eastern and western North Carolina. Though the policy cases result in additional transmission relative to the base, the similarities in the buildouts highlight the value of these routes across scenarios. By 2050, substantial additional capacity is added, connecting all four Carolina balancing areas, along with expanded ties between the Carolinas and their neighbors to the north (namely, Dominion Energy in Virginia) and south (primarily Southern Company in Georgia).

Because ReEDS models only the interfaces between balancing areas, these transmission capacity estimates omit investments that would be needed within a balancing area to support increased transfers of energy. Accordingly, actual transmission investments will likely be higher than the estimates provided here. The value of increased transmission as Duke Energy integrates more wind, solar PV, and other clean power resources to meet its carbon reduction goals is further reflected by the increase in power transfers from the operational modeling, described further in sections 4.1.3 and 4.2.2. This study also did not explore investments in high-voltage DC transmission lines or the option to invest in a larger macrogrid connecting the Southeast to other regions.

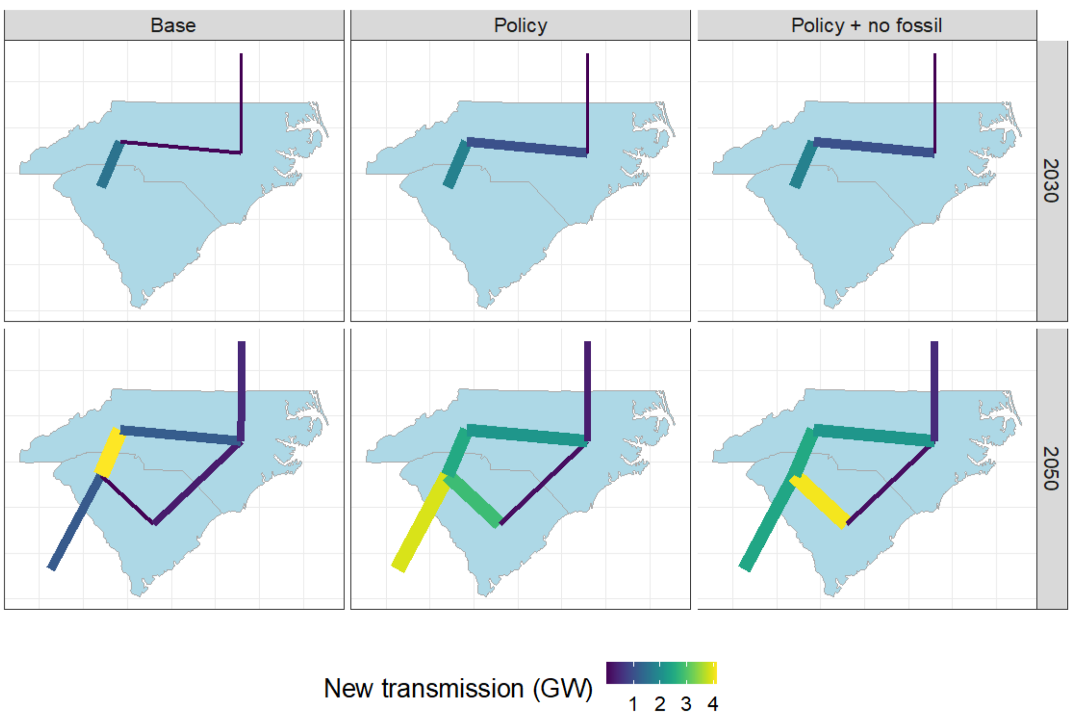

Figure 25. Map of new transmission investments (GW) between the ReEDS balancing areas in 2030 and 2050 for the three core scenarios

In addition to location, the timing of the transmission investments is important to consider. Figure 26 highlights the timing of the investments as determined by ReEDS in the cost-optimal pathway for each scenario, with results shown for every other year. By 2030, the capacity expansion simulations show results in cumulative transmission costs of $3.5 billion in the base case and approximately $6.5 billion in the policy scenarios. Although the policy target results in additional expenditures in transmission in 2030, this investment offsets some additional

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transmission investments that the base scenario undertakes in later years, and the gap between the base and policy cases decreases from \$3 billion to \$2 billion by 2040.

The difference is more substantial when modeled out to 2050, with \$11 billion in the base case and approximately \$21 billion in the policy cases. This widening gap reflects, in part, the increasing costs of approaching a 100% carbon-free system. Although ReEDS yields substantial transmission buildouts in 2030 and 2050 to meet the prescribed policy targets, in practice, these builds would need to be spread out over time to account for siting, permitting and planning, construction, and interconnection constraints.

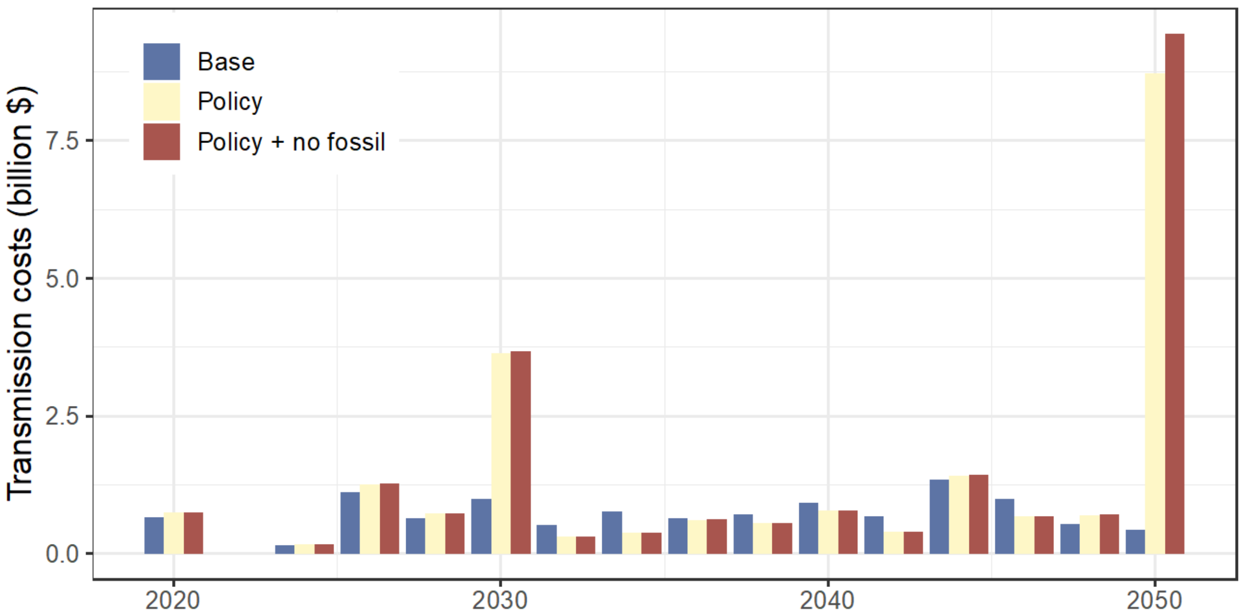

Figure 26. Summary of total transmission investment costs (2018 \$U.S. billion) by scenario. Note that results are shown only biennially because ReEDS was modeled only every other year.

3.3 Emissions and System Cost

Total CO_2 emissions by year for both Carolinas and only North Carolina are shown for the main scenarios in Figure 27. CO_2 emissions decrease over time in the base case, but the North Carolina emissions policies accelerate these reductions to comply with the 2030 target and to ensure that the state reaches zero-carbon emissions in 2050. The assumption of linear emissions reductions from 2030 to 2050 is a binding constraint for the first 10 years after 2030, after which emissions reductions slightly accelerate. The policy case leaves approximately 13 MMT CO_2 of annual emissions in South Carolina, with those emissions being eliminated in the scenario that requires all fossil fuels in the Carolinas to retire.

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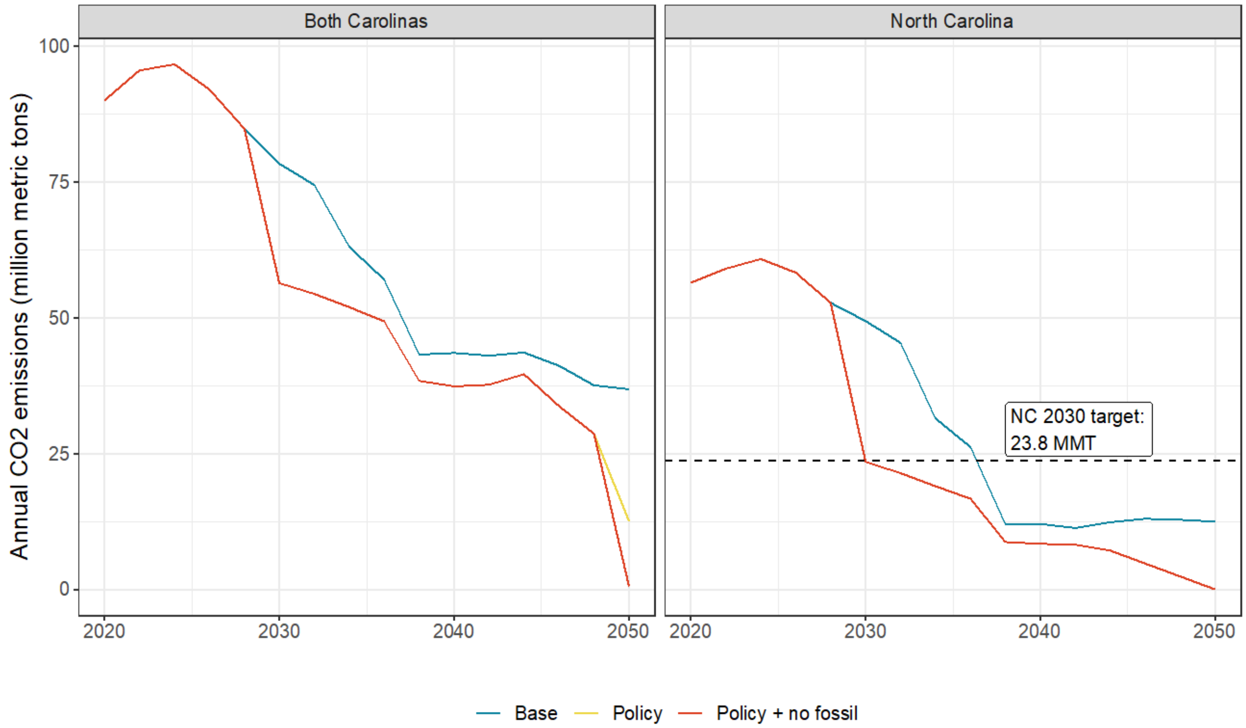

Figure 27. Total CO_2 emissions emitted in both Carolinas (left) and North Carolina (right) in each main ReEDS scenario

Figure 28 summarizes the net present value of the cumulative bulk system costs for the Carolinas through 2050. These costs include all bulk system capital expenditures (investment in generation, transmission, and storage), operational costs from dispatch (including fuel costs, variable operation-and-maintenance costs, and fixed operation-and-maintenance costs), and costs associated with purchased/imported energy (based on the cost of power in the exporting region plus a $10/MWh hurdle rate). The totals shown are net of the value of any tax credits received—either through a production tax credit or the investment tax credit. Importantly, however, the reported costs exclude the costs of servicing any debt on any investments made prior to 2020; the costs of energy-efficiency and demand response programs; and the costs of distribution system investments, operations, and maintenance—all costs that Duke Energy will face, but they are outside the scope of this analysis. Future costs are discounted to present dollars assuming a 5% discount rate.

The policy case results in total system costs of $170 billion, an additional $8 billion relative to the base case. The policy with no fossil fuel requirement amounts to $175 billion. Undiscounted, the total policy costs exceeding the base case are $45 billion and $85 billion, respectively.

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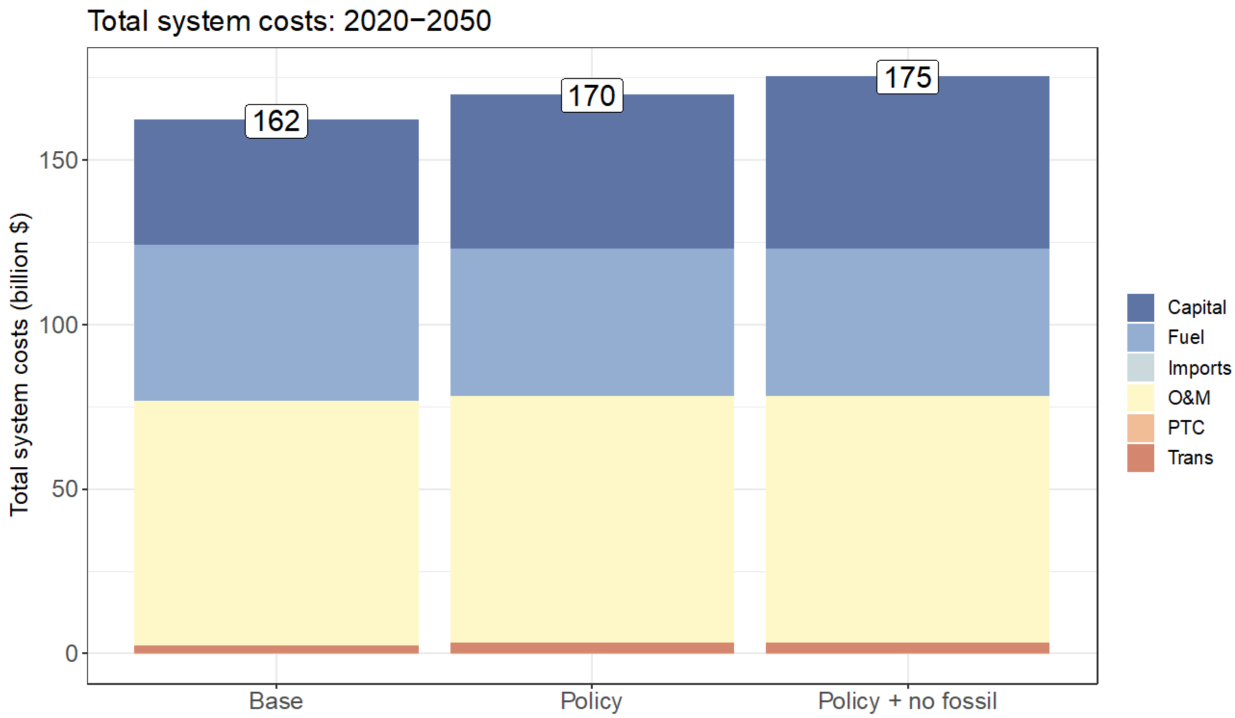

Figure 28. Total discounted system costs for the Carolinas by scenario for 2020–2050 (2018 $U.S.)

Note that this includes the full capital expenditures of any investments occurring through 2050. Future costs are discounted to present values assuming a 5% discount rate.

Undiscounted, annualized expenditures are broken down by category in Figure 29. Note that the annualized expenditures assumed that capital costs are annualized over a 20-year lifetime using technology-specific capital recovery factors but that the full lifetime investments made after 2030 for technologies with 20-year lifetimes are not shown because those would extend beyond 2050. The figure shows diminishing fuel costs over time as fossil-fueled generation is replaced by zero- or low-variable-cost resources, with capital payments and operation-and-maintenance costs taking larger shares.

Power system expenditures increase over time in all scenarios (including the base case), with an additional spike in costs as the system invests in additional capacity and transmission to achieve zero-carbon emissions in 2050. This spike reflects the increasing incremental cost of removing the last bit of CO_2 from the system. Figure 30 further explores this dynamic by plotting the cumulative emissions savings and cumulative policy costs (relative to the base) from 2030 to 2050. From 2030 to 2048, the system reduces CO_2 emissions by 186 MMT at a cost of $3.7 billion relative to the base scenario; in contrast, reducing the subsequent 33 MMT in cumulative emissions costs an additional $2.2 billion (not including annualized capital costs after 2050).

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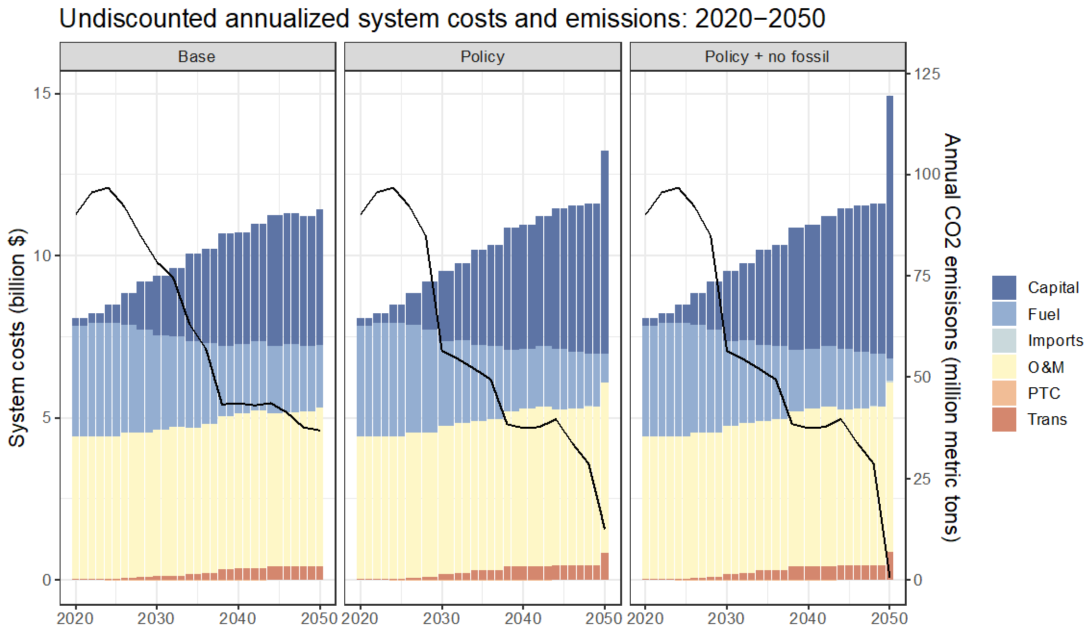

Figure 29. Annualized undiscounted system costs for the Carolinas by scenario for 2020–2050 (2018 $U.S.)

Capital expenditures are annualized over a 20-year lifetime using a capital recovery factor that ranges from 6.5%–7%, depending on the technology. The black line indicates total CO_2 emissions in the Carolinas.

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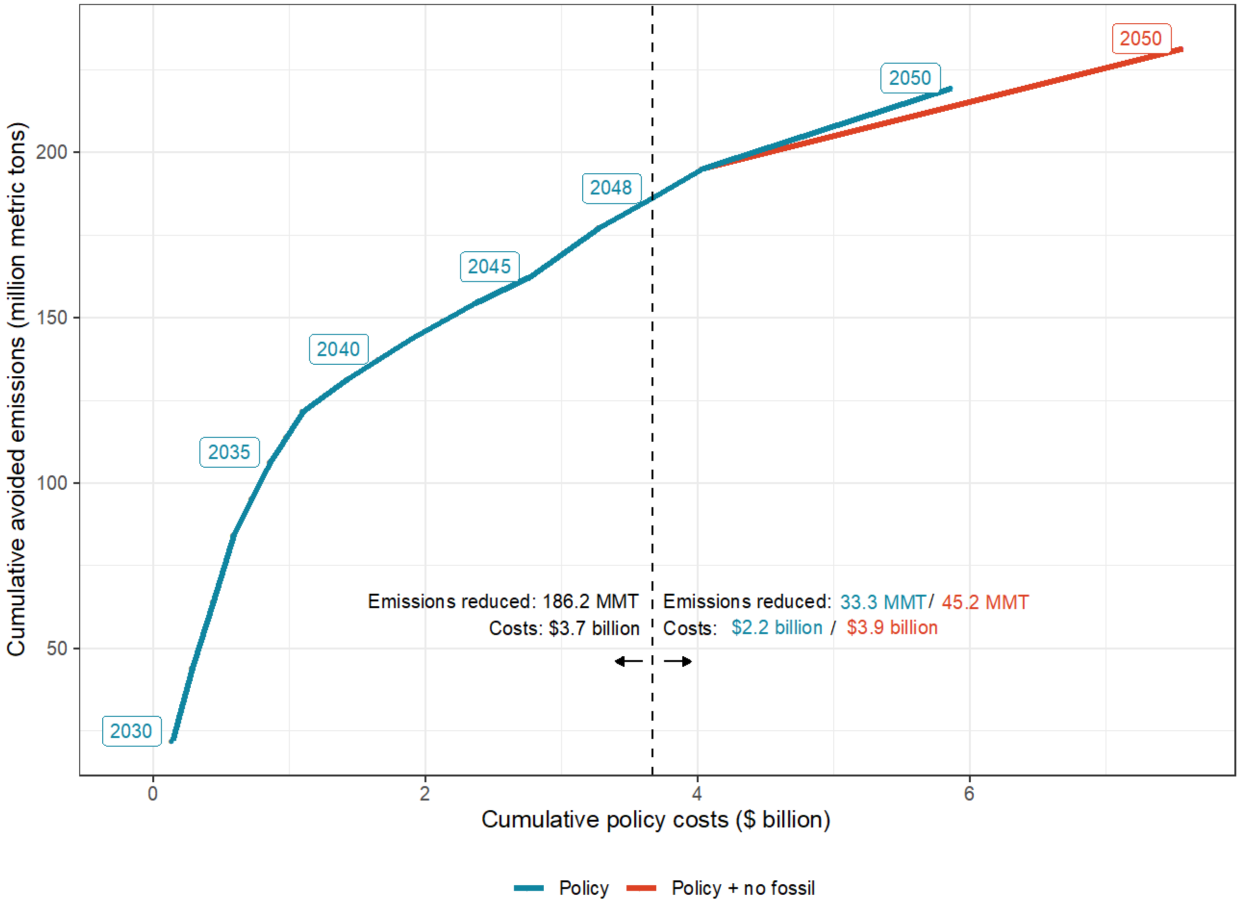

Figure 30. Cumulative policy cost (2018 $U.S. billion relative to the base case, x-axis) and cumulative avoided emissions (MMT CO_2, y-axis) for the Carolinas

Policy costs and avoided emissions are calculated relative to the base case. Each point represents 2-year increments between 2030 and 2050. Note that this figure does not include annualized capital costs after 2050.

Figure 31 provides estimates of the cumulative cost of mitigation ($/ton CO_2) in the Carolinas in the policy and policy + no-fossil scenarios, with avoided emissions and policy costs calculated as difference in these scenarios relative to the base case. The year 2030 incurs a relatively small cost of $7/ton for complying with the 2030 policy targets in North Carolina. In contrast, the cumulative cost of abatement for achieving the 2050 zero-carbon electricity target ranges from $27–$33/ton. Although the cumulative abatement cost is relatively low, the *incremental* cost of abatement increases quickly for reducing the last 5%–10% of emissions. For example, the average incremental cost of carbon mitigation in the Carolinas increases from approximately $40/metric ton in the years before 2050 to nearly $75/ton for the policy case and $97/ton for the no-fossil case in 2050, when the zero-carbon requirement is enforced.

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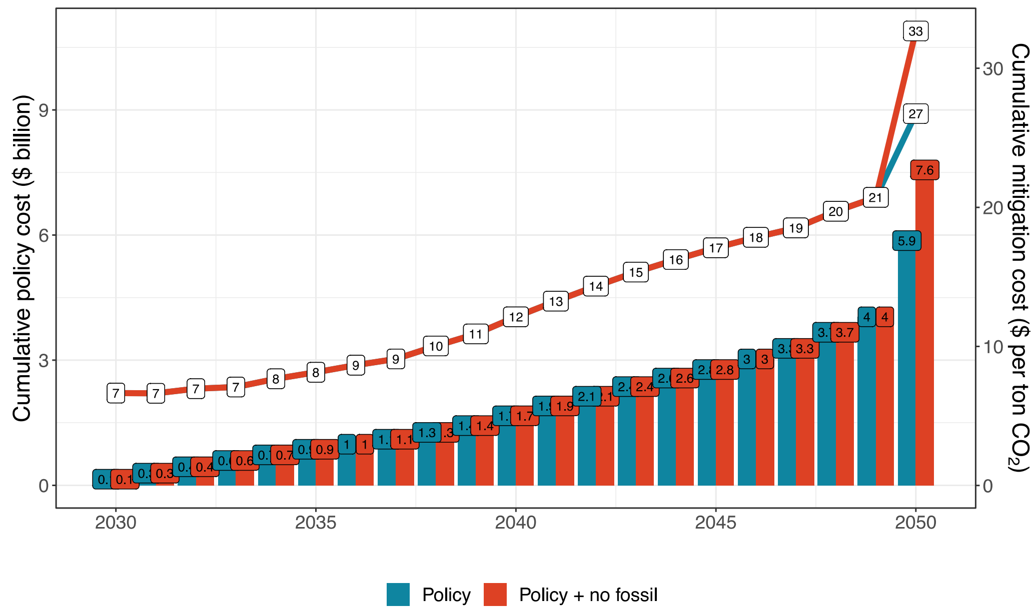

Figure 31. Cumulative policy cost (2018 $U.S. billion relative to the base case, left axis/bars) and cost of mitigation ($/ton CO_2 avoided, right axis/lines) for the policy and policy + no-fossil in 2050 cases

3.4 Sensitivities

3.4.1 Cost-Based Sensitivities

Figure 32 summarizes the capacity buildout for the base case and policy scenarios across the three different cost sensitivities: (1) high-cost solar PV and storage, (2) high-cost solar PV and storage coupled with low-cost natural gas, and (3) low-cost land-based wind. The subsequent figure (Figure 33) depicts the differences in installed capacities for each cost sensitivity relative to the baseline cost case.

Intuitively, the higher-cost trajectories for solar PV and storage reduce the installed capacity of these resources, although large shares of both are still deployed in both the base and policy scenarios. Although in the base case higher-cost solar and storage shift more capacity to land-based wind and natural gas, in the policy case, these scenarios incentivize more investments in offshore wind. The low cost for land-based wind in that sensitivity results in significant additional land-based wind resource (20–25 GW) relative to the baseline cost assumptions.

Figure 34 depicts the annual generation from solar PV as a share of total generation in the Carolinas for each cost case. In the policy case, the share of solar PV ranges from 35%–50% of total generation across the sensitivities. This suggests two key findings. The first is that solar PV is likely to play a large role in the generation of the decarbonized Carolinas across a range of cost pathways. The second is that the differences in solar PV shares across cost sensitivities imply benefit to hedging to different outcomes by investing in a diverse set of resources—including land-based and offshore wind and renewable fuels—that can complement solar PV and storage.

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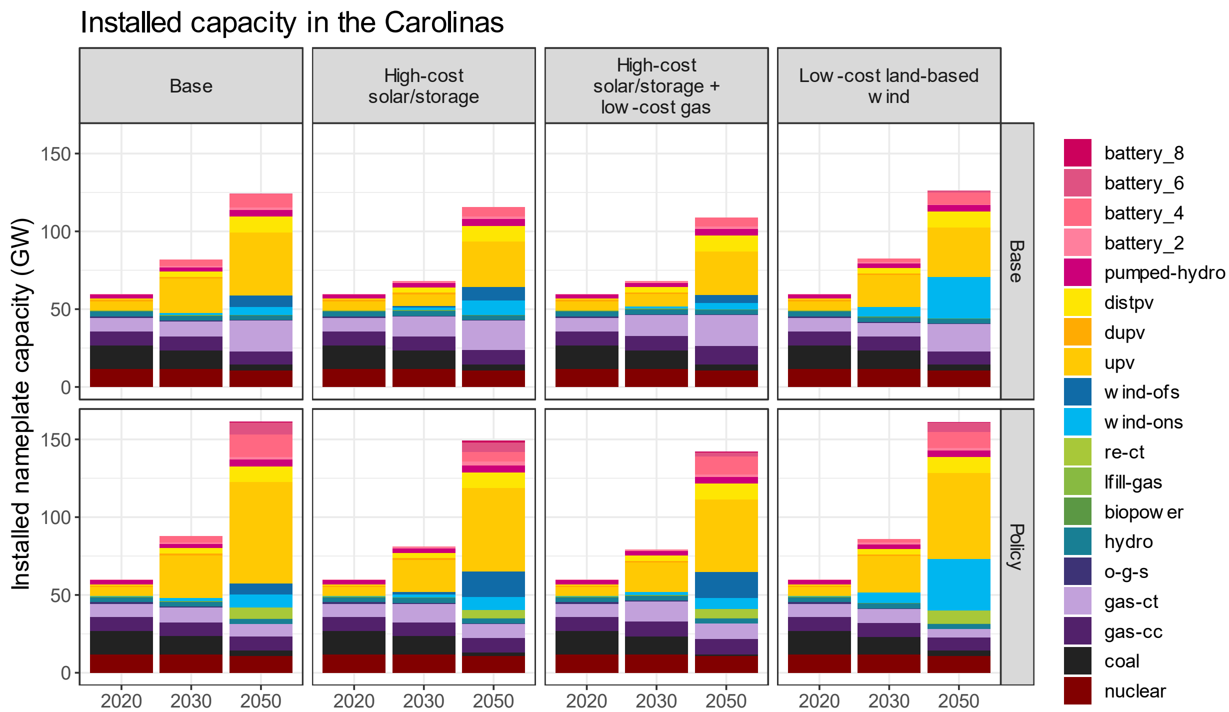

Figure 32. Total installed capacity for the baseline assumptions and cost sensitivities

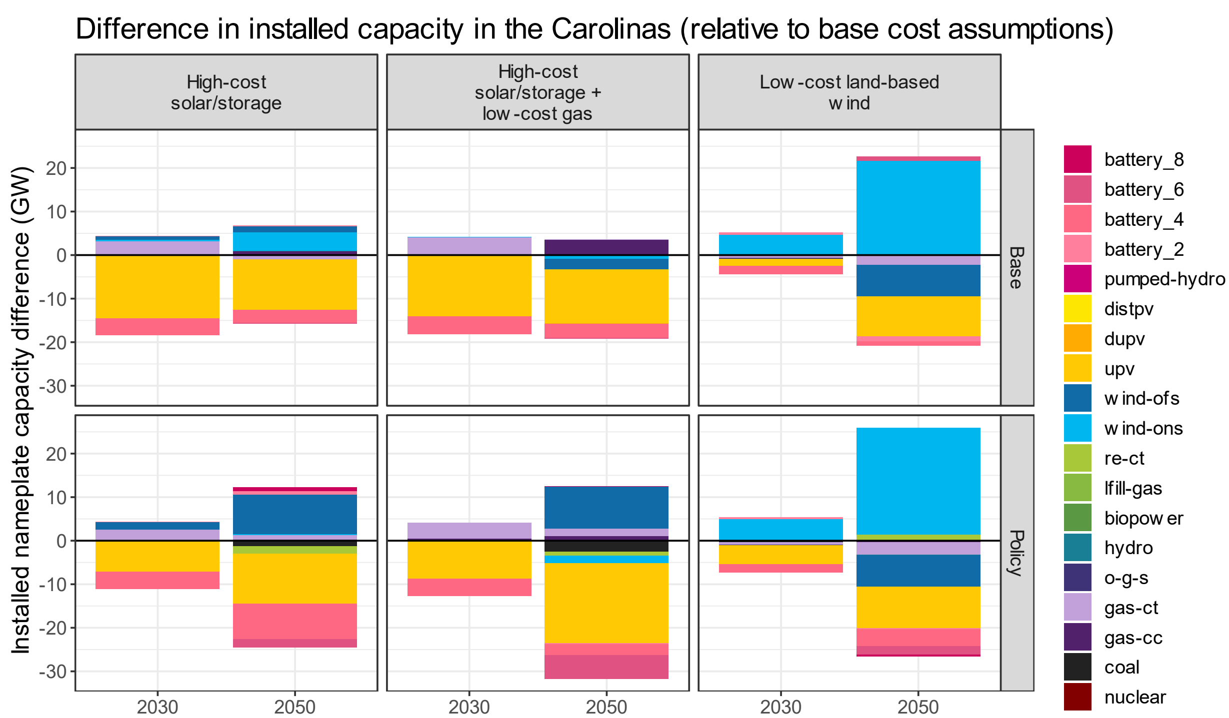

Figure 33. Differences in installed capacity for the cost sensitivities (relative to the baseline cost assumptions) in both the base case and policy emissions cases for the Carolinas

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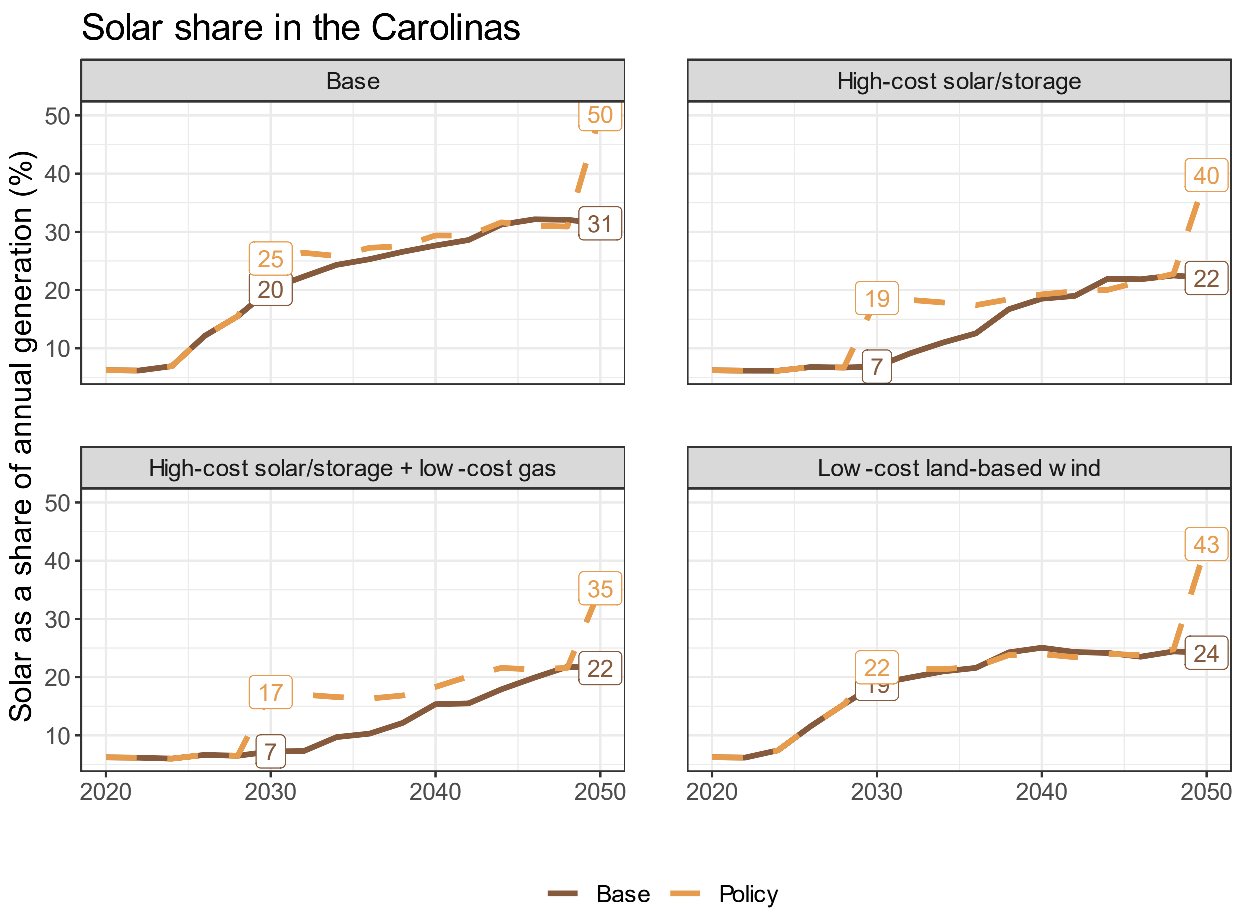

Figure 34. Annual generation from solar PV in the Carolinas (percentage of total generation) for the cost sensitivities

3.4.2 Wind Technology and Availability

This section explores the sensitivities to different assumptions related to wind, namely, a case with limited ability to develop land-based wind projects and a case with more state-of-the art wind turbines (see the end of Section 2.1 for details on the assumptions of these sensitivities). Figure 35 presents the total capacity for each sensitivity case, and Figure 36 provides the differences in installed capacities relative to the baseline assumptions for the base case and the policy scenarios, respectively. In the limited access case, hurdles to deploying land-based wind are compensated for with increased deployments of offshore wind resources, along with additional solar PV, storage, and RE-CT capacity.

Similarly, the advanced turbine case results in higher deployment of offshore wind, with approximately 10 GW more capacity than the base case. This is driven by the availability of larger offshore wind turbines: The base case assumes a 6-GW turbine with a hub height of 100 m and a rotor diameter of 155 m^2, whereas the advanced case assumes a 15-GW turbine with a hub height of 150 m and a rotor diameter of 240 m^2. The result is substantially higher capacity factors (see Figure A-1 in Appendix A), increasing the value of the offshore resource from the perspectives of both energy and planning reserve. In the case of the advanced turbine, the additional 10 MW of offshore capacity replaces nearly 20 GW of combined solar PV, storage, and peaking capacity resources, reflecting the value of this technology in adding diversity to the system.

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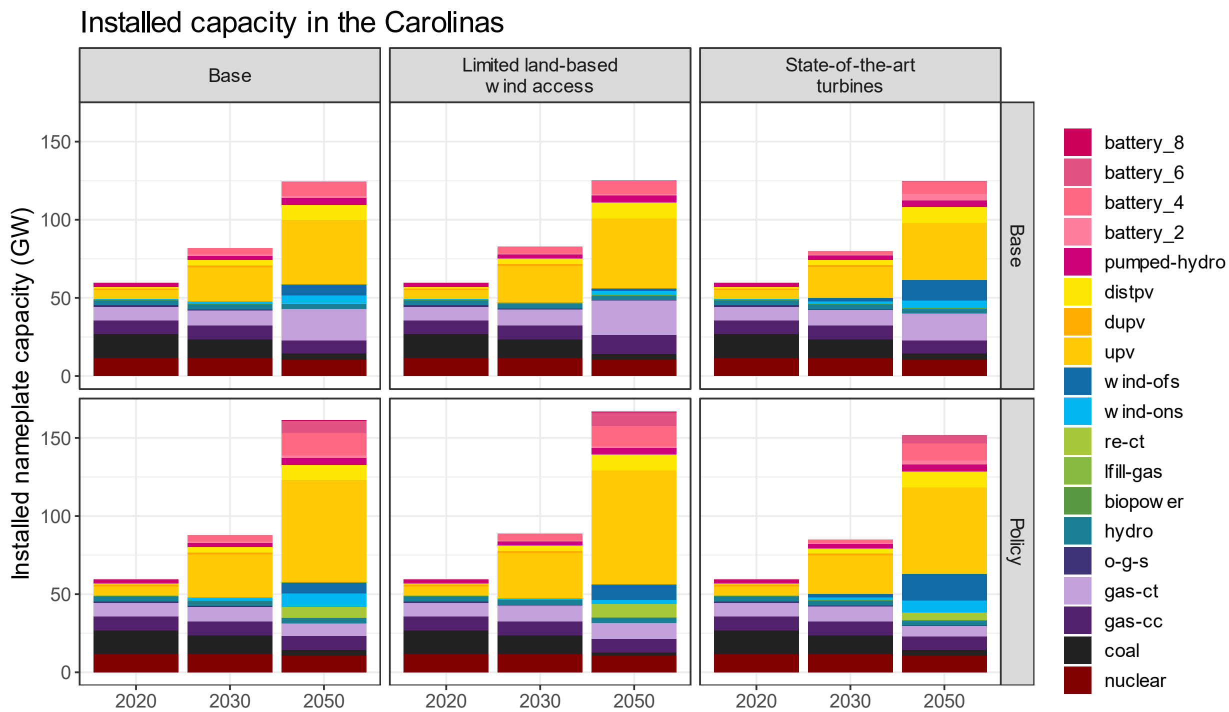

Figure 35. Total installed capacity for the baseline assumptions and wind sensitivities

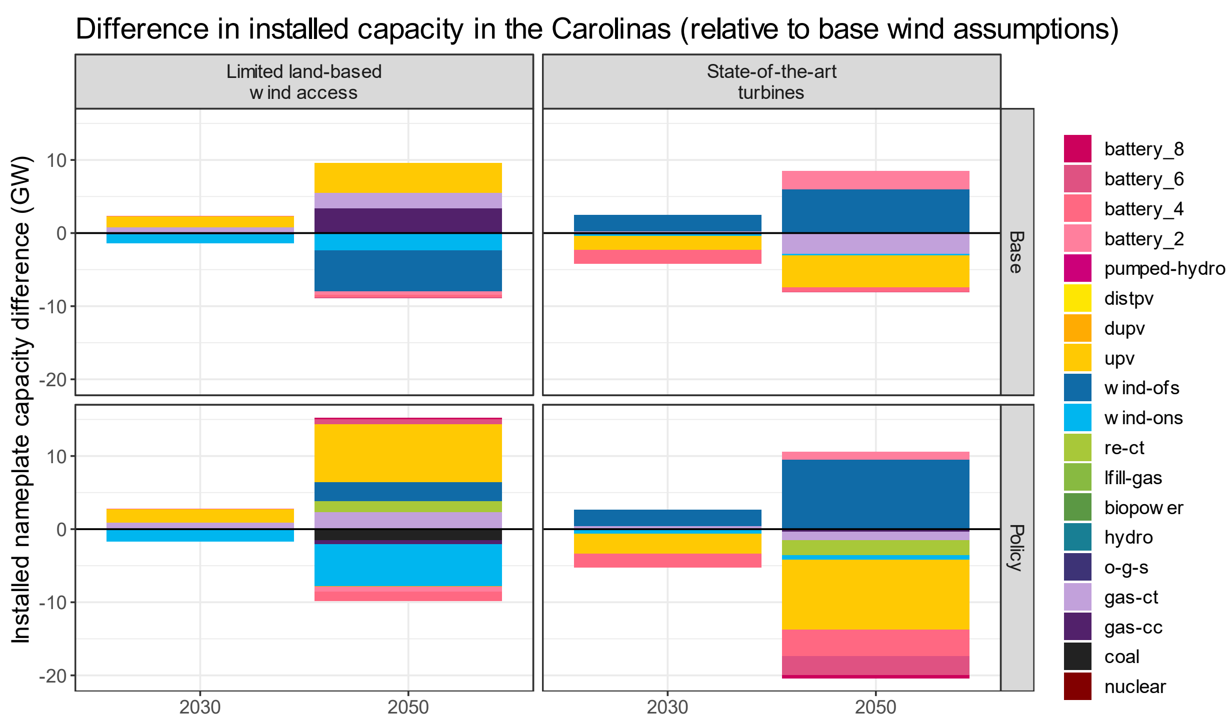

Figure 36. Difference in installed capacity for the wind sensitivities (relative to the baseline wind assumptions) in both the base case and the policy emissions cases for the Carolinas

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3.4.3 Operational Sensitivities

This study analyzed a select number of operational sensitivities related to (1) the ability of Duke Energy to rely on its neighbors for firm capacity planning; (2) whether Duke Energy's neighbors in the Eastern Interconnection adopt a zero-carbon electric generation mix by 2050; and (3) whether the Carolinas and its neighbors pursue "high-electrification" pathways that include electric vehicle adoption, electrification of heating, new energy-efficiency measures, and changes to load flexibility.

As in the previous sensitivity analyses, Figure 37 provides the total capacity by scenario, and Figure 38 shows the difference in capacity from the baseline assumptions. In the case where Duke Energy can export and import firm capacity from its neighbors, the model reduces investments in peaking resources (e.g., RE-CTs) that are physically located in the Carolinas, instead opting for more offshore wind, solar PV, and storage. In this scenario, the system optimizes builds across a larger region than only the Carolinas, using more VRE to export power to neighbors but relying on outside sources for capacity during peak hours. Notably, this approach would require close coordination and analysis to ensure that the region is not exposed to correlated failures across service territories.

Having the entire Eastern Interconnection pursue net zero for the power sector results in increased energy storage capacity. This is primarily driven by doubling the 4-hour battery storage capacity relative to the policy case with no Eastern Interconnection emissions target, although the model also increases the deployment of 6- and 8-hour storage. This sensitivity also yields increased PV and offshore wind; however, the increased storage capacity installed in the Carolinas also partially alleviates some need for firm peaking capacity resources, such as RE-CTs. The larger deployment of longer-duration energy storage resources in this sensitivity reflects the increased value of these resources as more of the surrounding regions integrate zero-carbon resources, which, in turn, reduces the ability for Duke Energy to manage excess renewable generation solely through exports.

Under the high-electrification scenario, installed capacity in 2050 is substantially higher in the policy case (almost 210 GW) relative to the policy case with base assumptions (161 GW). The capacity mix is similar to the other policy cases, with additional capacity to supply load from electric vehicles and electrified space heating coming from solar PV, 4-hour battery storage, offshore wind, and RE-CTs.

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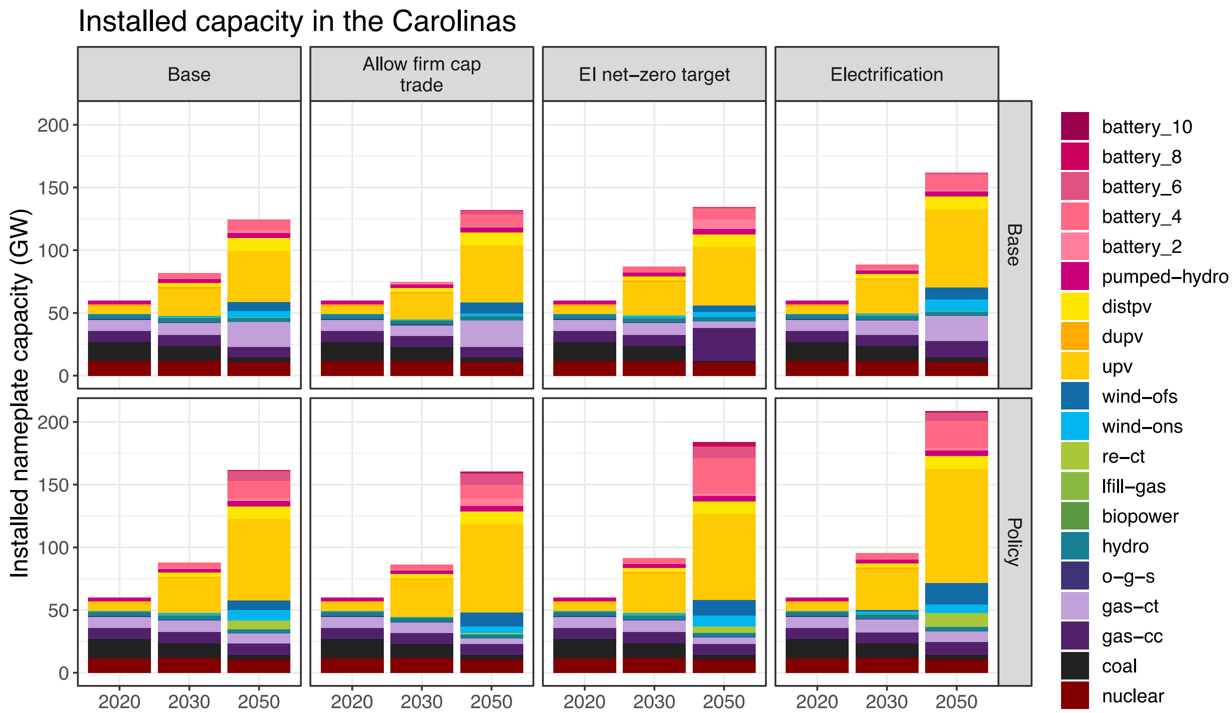

Figure 37. Total installed capacity for the baseline assumptions and operational sensitivities

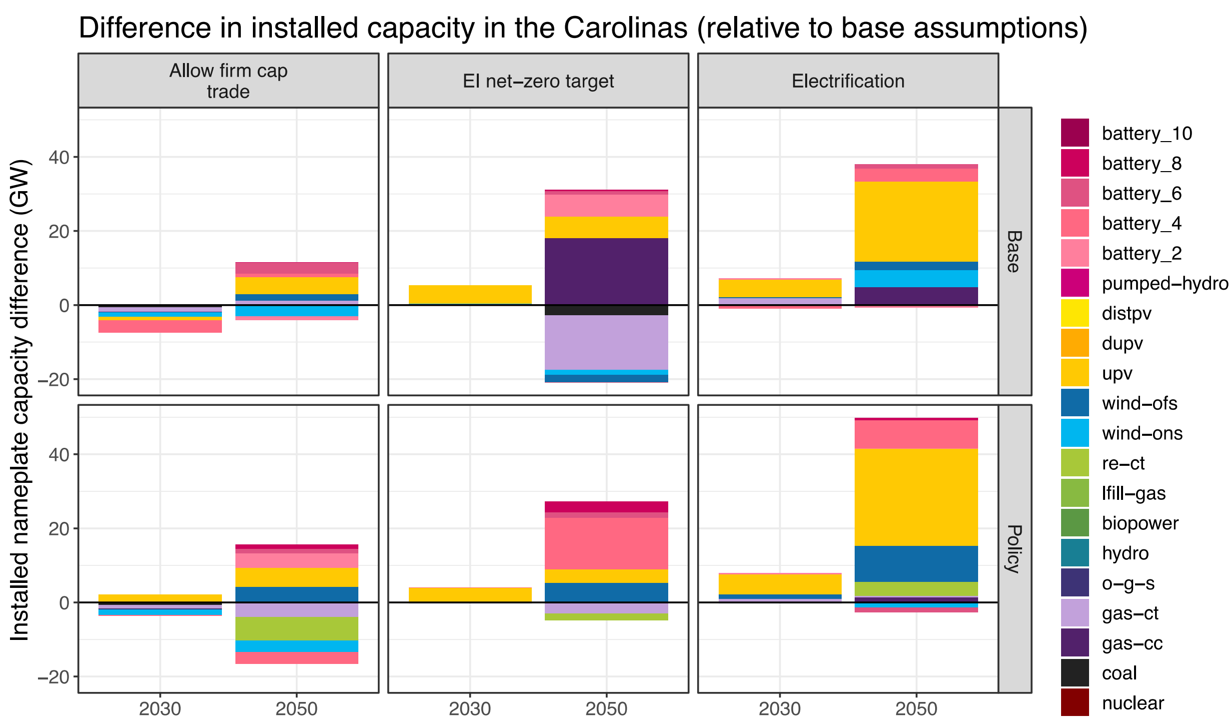

Figure 38. Difference in installed capacity for the operational sensitivities (relative to the baseline assumptions) in both the base case and the policy emissions cases for the Carolinas

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3.4.4 Summary of Costs Across Sensitivities

Figure 39 summarizes the net present value of cumulative costs through 2050 (see Figure 28 and surrounding text for the results from the main cases). The cost sensitivities have intuitive effects on system costs: Higher-cost solar PV and storage increases the cost of the policy scenarios, whereas low-cost wind reduces cost. Cumulative system costs are within 3% of the total cost of the carbon emissions policy scenario under the baseline assumptions for each policy sensitivity, except for the Eastern Interconnection zero-emissions and high-electrification sensitivities, which have higher costs. Comparing each policy sensitivity to its base counterpart, the cumulative net present value of the incremental costs of the emissions policy ($8 billion in the base case) falls between $6–$13 billion across the range of sensitivities.

The costs of CO_2 mitigation across each sensitivity are presented in Figure 40. In some cases, the results might seem counterintuitive; for instance, the low-cost wind and advanced turbine scenarios have higher costs of mitigations than the base assumptions. This is because the low-cost wind trajectory results in substantially more wind being adopted in the base case of that sensitivity. This reduces emissions in the base case of that sensitivity, meaning that the costs of the full decarbonization are spread out over fewer tons of avoided CO_2. Generally, the cost of mitigation ranges from $6–$10/ton in 2030 and from $20–$35/ton in 2050, with a few sensitivities providing outlying values. Similarly, the electrification sensitivity has higher cumulative system costs but lower costs of mitigation primarily because the base electrification case emits more CO_2 as a result of increased load, thus increasing the reductions in the associated policy case.

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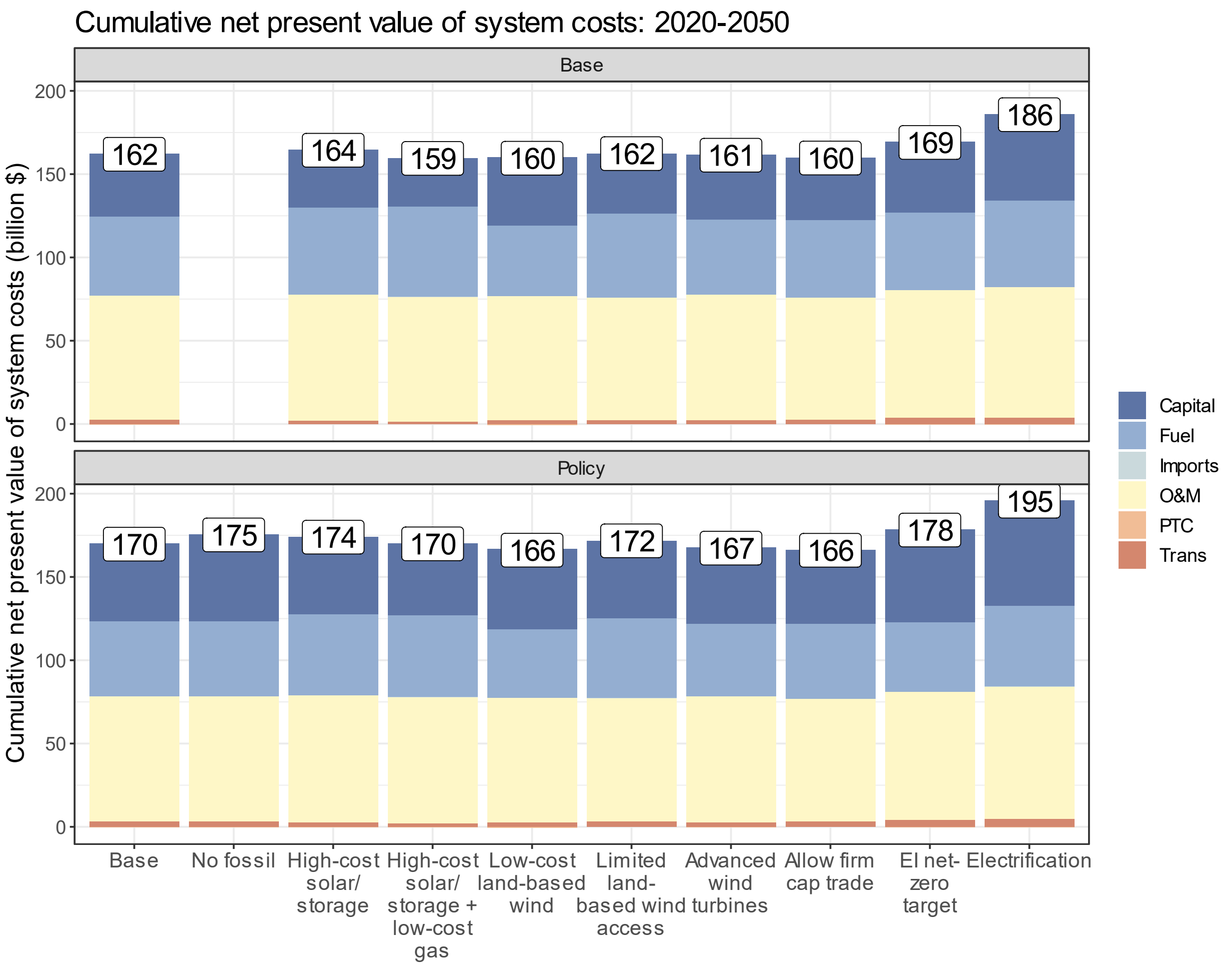

Figure 39. Total discounted system costs for the Carolinas by scenario and sensitivity for 2020–2050 (2018 $U.S.)

Note that this includes the full capital expenditures of any investments occurring through 2050. Future costs are discounted using a 5% discount rate. Note that costs are higher for the electrification sensitivity, but that case also serves more total MWh of demand.

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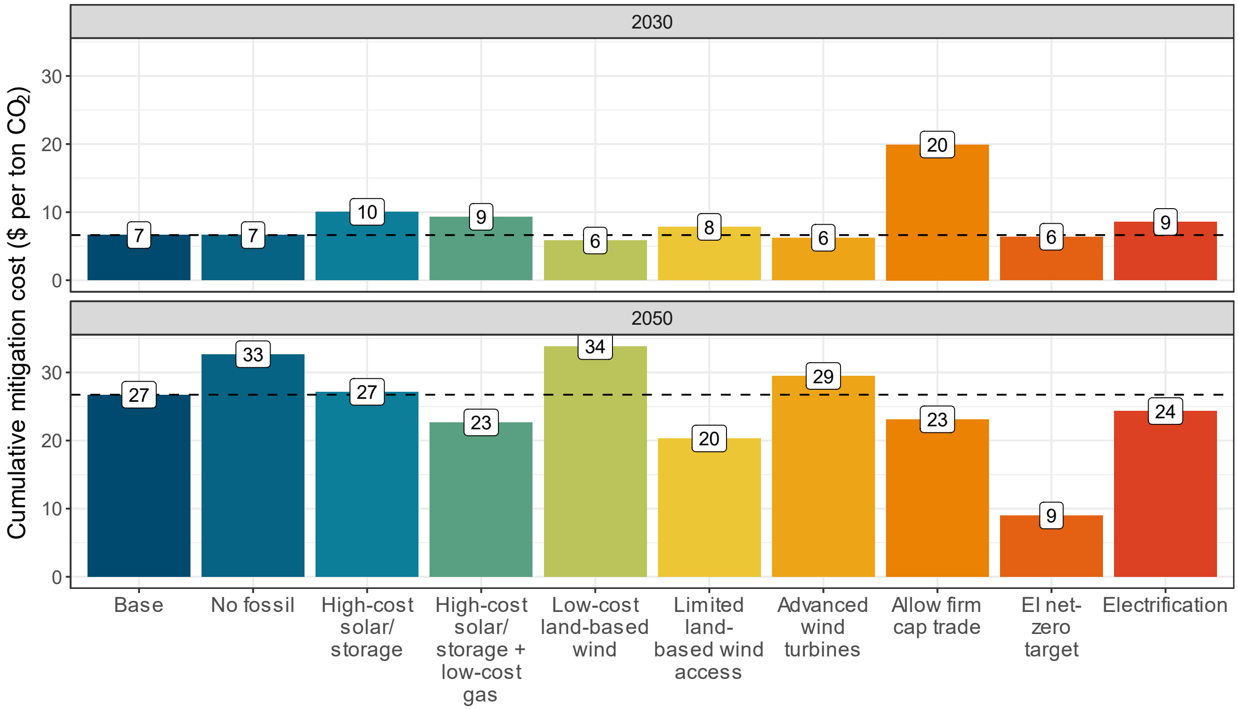

Figure 40. Cumulative cost of mitigation ($/ton CO_2 avoided) in 2030 and 2050 for the policy scenario of each sensitivity case compared to the corresponding base case for each sensitivity

The cost of mitigation is calculated using the difference in emissions and the costs of the policy case relative to the base case for each sensitivity. Cumulative emissions/cost differences are assessed starting in 2030. Note that the estimated costs of mitigation are for the power sector only; additional emissions reductions in other sectors in the electrification scenario are not considered.

Another aspect from which to evaluate the sensitivity runs is the investment in transmission infrastructure. Although ReEDS does not model transmission within balancing areas, it does capture the interchange between balancing areas, and it allows investments in new transmission capacity between Duke Energy and its neighbors. Figure 41 illustrates the total new transmission capacity built through 2050 between balancing authorities within the Carolinas or between the Carolinas and its neighbors to the south (Georgia) or north (Virginia).

Across the various sensitivities, the policy cases require more transmission investments to accommodate increased levels of renewable and storage capacity. Investments in transmission between the Carolina balancing authorities reflect the need for enhanced capabilities to transmit power from solar PV, wind, and storage—which is not necessarily geographically aligned with traditional generation—to load centers. A summary of the total investment cost in new transmission is provided in Table 7.

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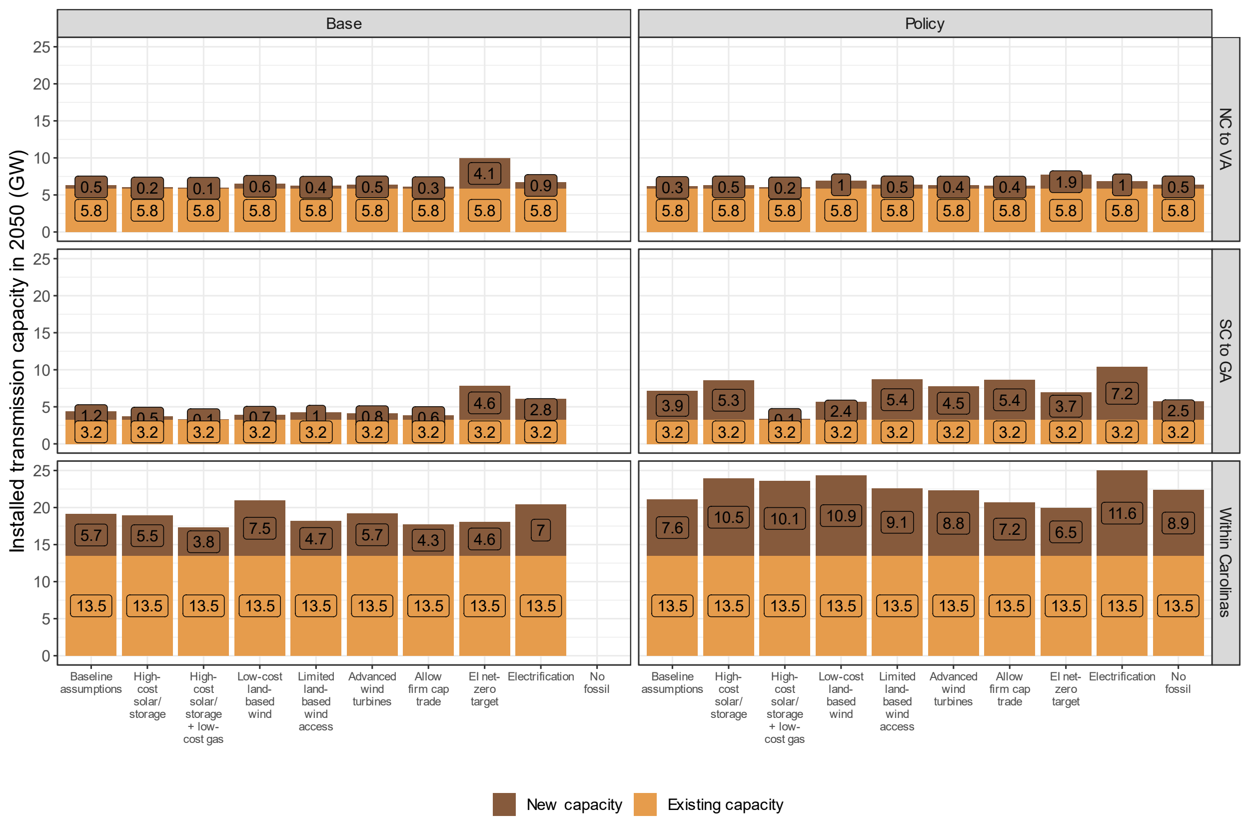

Figure 41. Installed transmission capacity (GW) in 2050 for various sensitivities in the base case and policy emissions scenarios

Existing capacity values reflect existing transmission in 2020, whereas new capacity indicates additional transmission capacity investments from 2020 to 2050.

Table 7. Total Investment Cost of New Transmission through 2050 (2018 $U.S. billion)

Sensitivity	Net Present Value Using 5% Discount Rate		Undiscounted Total	
	Base	Policy	Base	Policy
Baseline assumptions	$3.28	$5.12	$11.21	$21.14
High-cost solar PV/storage	$2.54	$5.45	$8.86	$25.63
High-cost solar PV/storage + low-cost gas	$1.75	$4.09	$6.08	$18.93
Low-cost land-based wind	$2.45	$4.27	$7.17	$18.56
Limited wind access	$2.95	$6.82	$10.52	$33.17
Advanced wind turbines	$2.94	$5.11	$9.86	$23.36
Allow firm cap trade	$3.37	$5.76	$11.86	$25.60
Eastern Interconnection net-zero target	$5.27	$5.65	$20.25	$20.92
Electrification	$4.74	$7.85	$16.25	$33.57
No fossil	--	$5.25		$21.96

4 Operational Modeling Results

As noted in Section 2.3, we test select ReEDS cases for operational performance with production cost modeling in PLEXOS. This section provides an overview of the results of both sets of cases tested:

- A model with full nodal and transmission representation, used to test a 2024 base case, the 2030 policy case, a 2030 case with accelerated coal retirements, and a 2036 case with alternate load and resource profiles
- A model with zonal representation, used to test a 2024 reference case and the 2050 policy cases (including the scenario in which all fossil fuel in the Carolinas must retire).

Details on the methods used in the production cost modeling are provided in Section 2.3. The following sections present the results of the production cost modeling, starting with the nodal model analysis of 2030, and following with the zonal model analysis of 2050.

Note that the 2024 base case is not intended to represent a future projection but rather to serve as a benchmark from which to compare the policy cases. In each case, we evaluate the operations of these systems based on metrics such as annual generation and dispatch during critical time periods, energy interchange with neighboring regions, and VRE curtailment.

4.1 Nodal Model

The nodal model represents each balancing area separately, so the results in this section are reported for Duke Energy (not the Carolinas as a whole). Figure 42 provides a summary of the installed capacity in Duke Energy's service territory for each nodal case examined.

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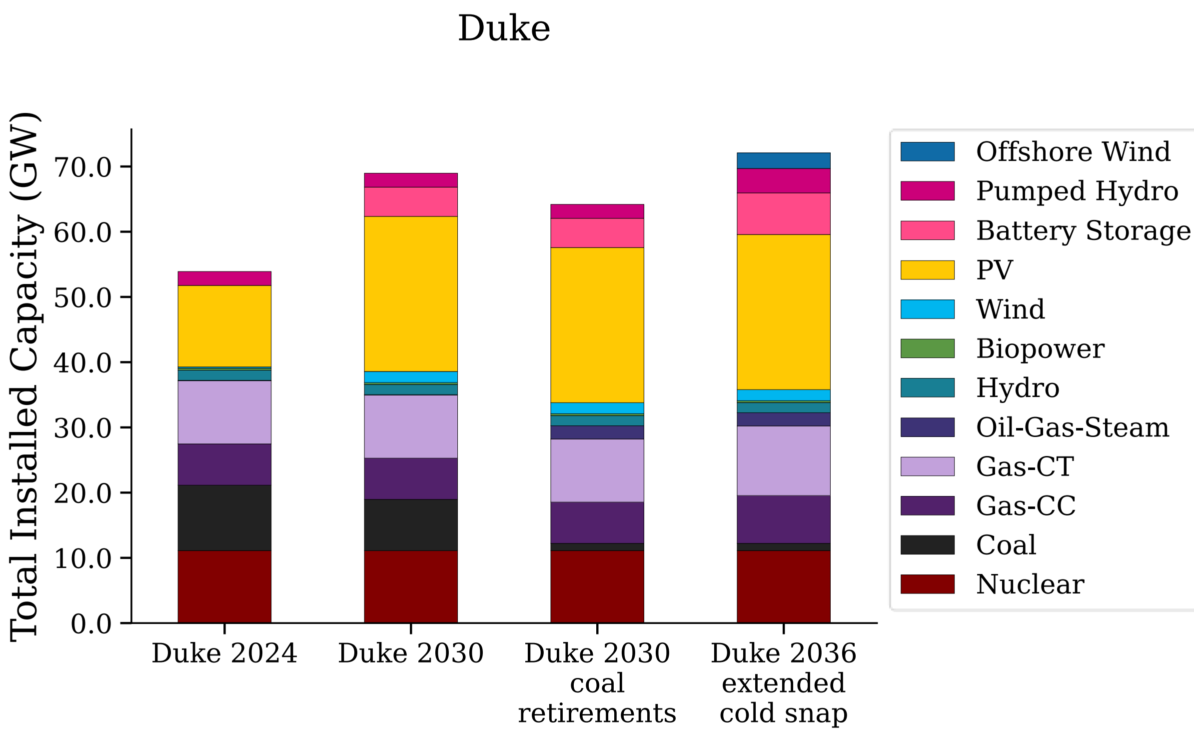

Figure 42. Total installed generation capacity in Duke Energy's territory in each case used in the nodal production cost modeling

Here, *battery storage* refers to the battery storage of various (2-, 4-, and 8-hour) durations. [15]

4.1.1 Annual Generation and Dispatch

Figure 43 provides the annual generation, total load and load from storage charging, and curtailment for each scenario analyzed. Comparing the 2024 base case with the policy cases, we see generally declining coal dispatch because of retirements and low utilization. Reductions in coal output are compensated with increased generation from solar PV, which moves from 12% to 18%–21% of annual generation. Wind also plays a role, supplying as much as 7% of annual generation in the 2036 policy case. Nuclear remains a large source of emissions-free generation; note that all nuclear plants were configured in the production cost model to maximize output aside from scheduled outages. Declining coal generation is also partially offset with increased dispatch from natural gas.

Table 8 summarizes the share of total annual generation from each generation category. From 2024 to 2030, the share of carbon-free generation increases from 68% to 76%, with VRE resources (primarily solar PV) accounting for 24% of the total annual generation. Solar PV output declines slightly in 2036 because of lower resource availability in the winter and lower load in the summer—when solar PV is most available—both of which drive more curtailment. These declines are partially offset by the contribution from offshore wind, although additional gas generation is also used.

[15] Many of the plots for the operational modeling results were made using Marmot, an open-source tool developed for visualizing grid operations (Levie et al. 2021). Marmot is available at https://github.com/NREL/Marmot.

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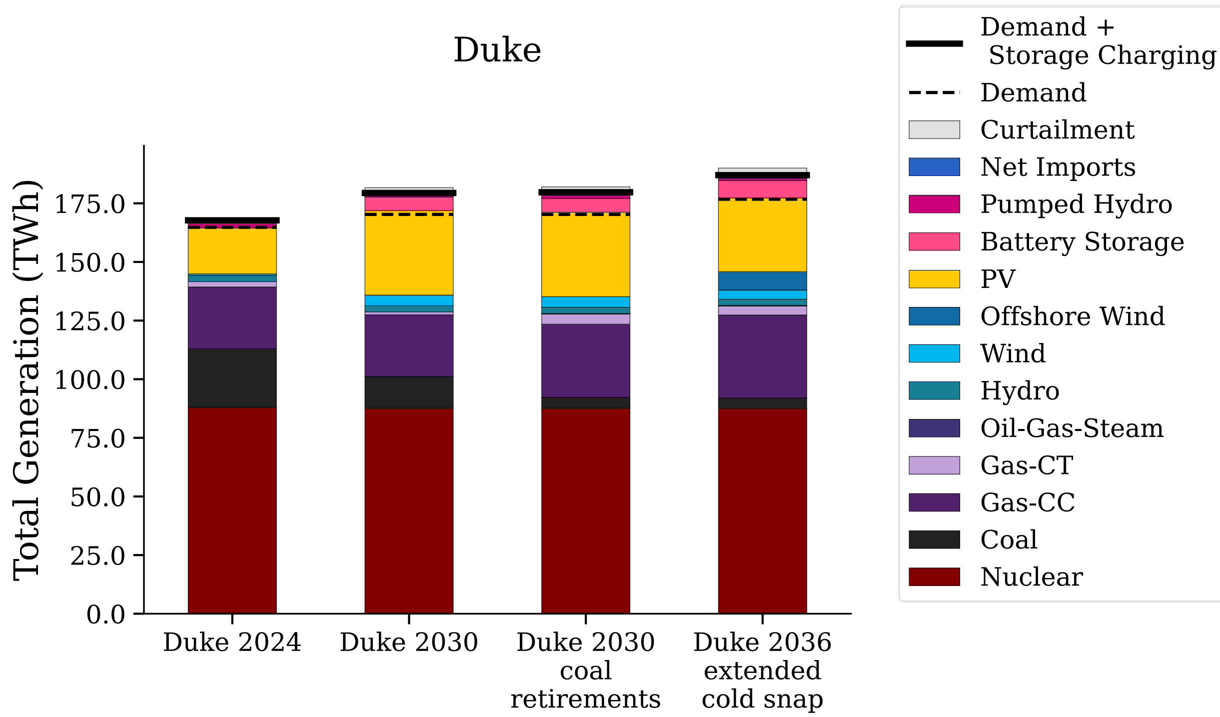

Figure 43. Annual generation by generator type for the nodal production cost modeling runs

Table 8. Annual Generation by Year (Percentage of Total Generation Mix) in Duke Energy's Balancing Authorities

	2024	2030	2030 Coal Retirements	2036 Extended Cold Snap
Nuclear	54%	51%	51%	49%
Coal	15%	8%	3%	2%
Gas-CC	16%	15%	18%	20%
Gas-CT	1%	1%	3%	2%
Hydro	2%	2%	2%	1%
Land-based wind	0%	3%	3%	2%
Offshore wind	0%	0%	0%	4%
Solar PV	12%	21%	21%	18%
Total carbon-free	67%	76%	76%	75%

Duke Energy's service territory in the Carolinas is dual-peaking, meaning that it experiences peak load periods in both summer and winter. Accordingly, it is important to explore how the system operates in both periods. Figure 44 and Figure 45 illustrate the hourly dispatch of the generating resources during the summer and winter peak periods, respectively. For plots of hourly dispatch for the entire year of analysis, see Appendix B.

In the summer period, 2030 and 2036 illustrate a shift away from using coal and relying more heavily on solar PV, storage, and natural gas to help meet peak load. Storage and gas become particularly important in the evening hours, when solar PV output declines. Storage devices primarily charge during the morning hours. Both land-based and offshore wind also help contribute to meeting evening and overnight load.

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Looking at the winter period, note the distinction between the 2012 and 2018 weather cases: Although both have relatively high peak loads, in 2012, this peak is relatively short; whereas in 2018, the period of high demand extends for several days. In the 2018 weather case, the system heavily relies on generation from natural gas to meet the sustained levels of high load coupled with relatively low levels of solar PV output. The system also uses storage—which primarily charges during the day and discharges overnight—and imports to help balance supply and demand. Although the solar PV output is low during several of these days, the wind output is relatively consistent, pointing to the role this resource plays in helping to meet peak net load requirements.

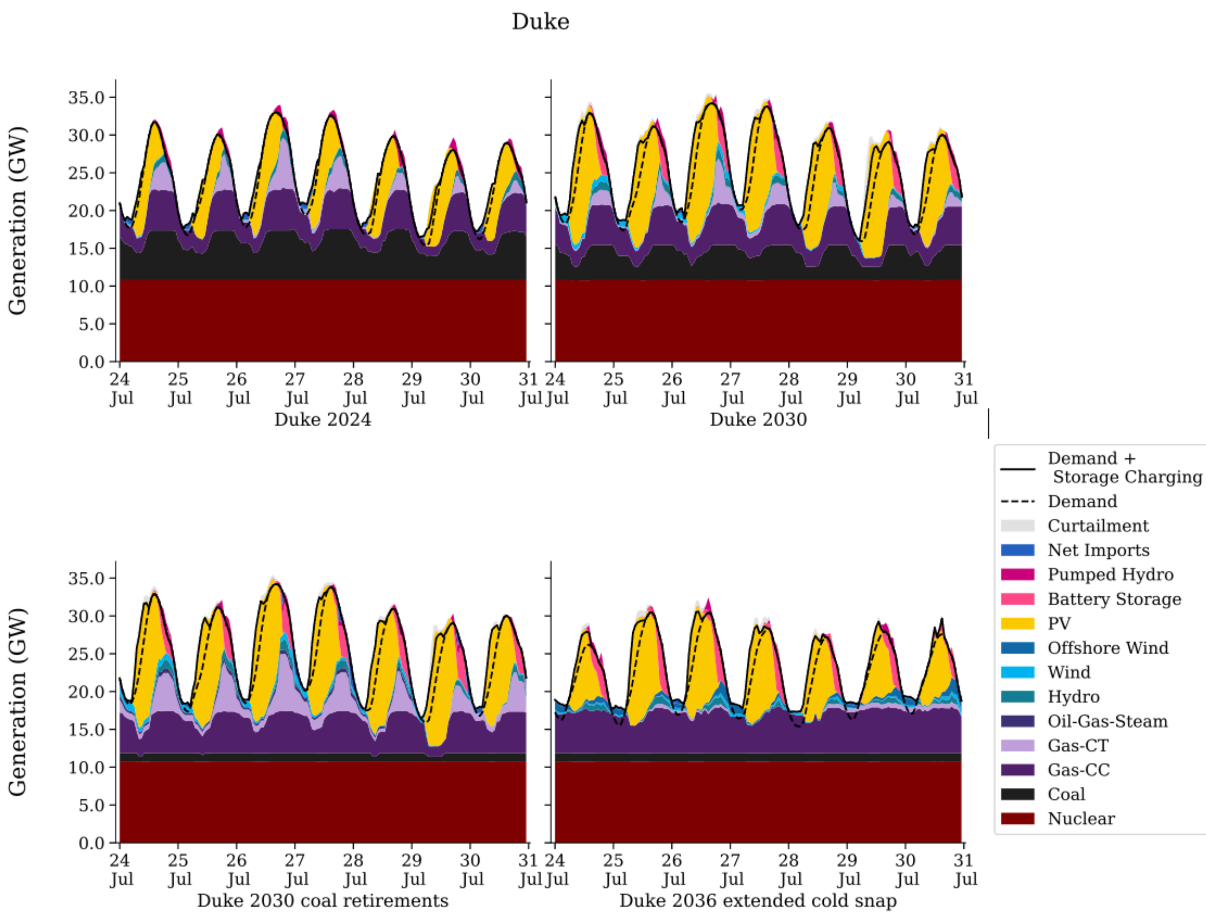

Figure 44. System dispatch during the summer peak for each nodal case

See Appendix B for dispatch results for the entire year of analysis.

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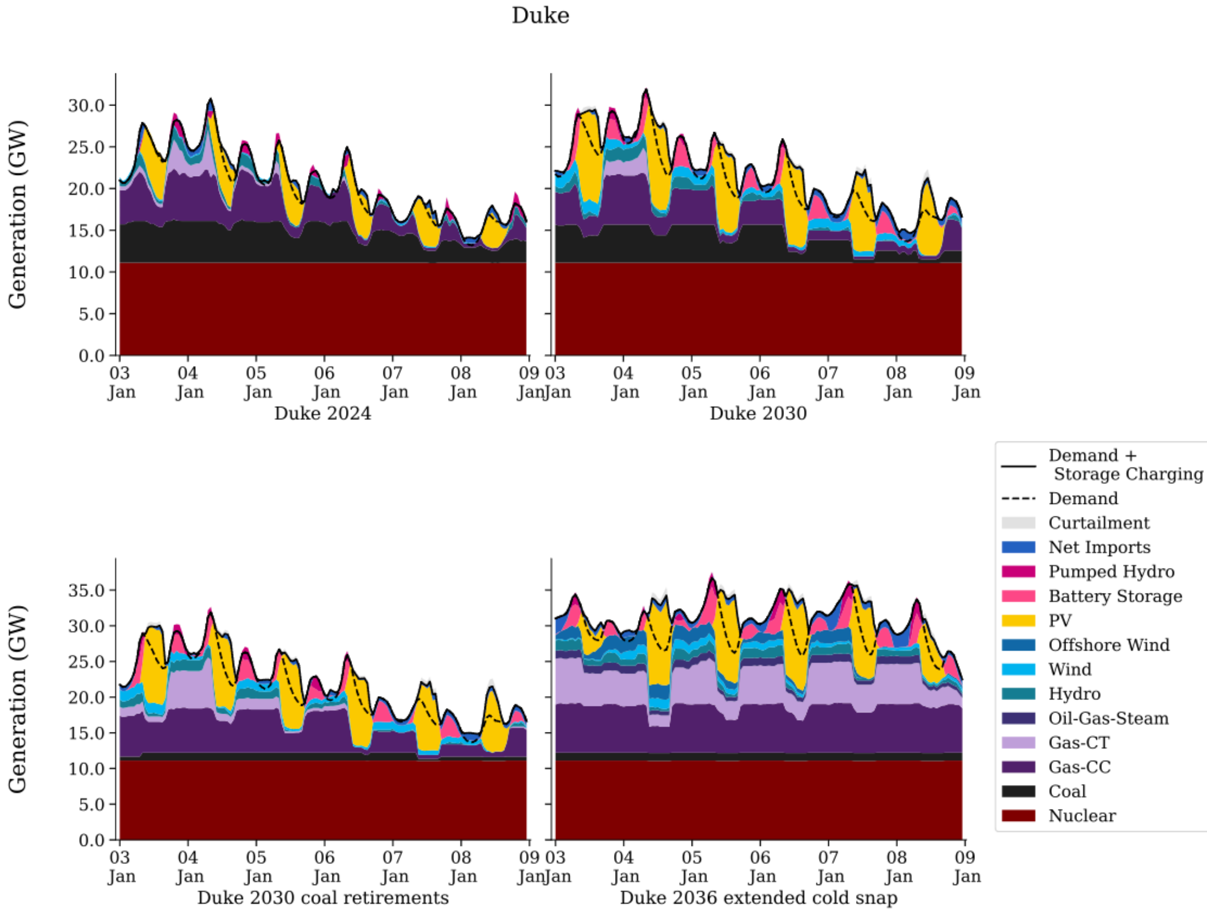

Figure 45. System dispatch during a winter peak for each nodal case

Note that the second row has a different y-axis scale. See Appendix B for dispatch results for the entire year of analysis.

The reliance on natural gas to help meet peak load requirements presupposes the availability of natural gas delivery via pipeline, which could be challenging to secure during the winter, when there are competing demands for natural gas. Figure 46 illustrates the total daily natural gas offtakes at Duke Energy's gas generating units. In the base case system, the total daily gas offtakes peak in the summer at approximately 1.2 billion cubic feet (BCF)/day. In the 2030 scenario with accelerated coal retirements, this peak shifts to the winter and increases to 1.7 BCF/day. The 2036 case is even more pronounced because the extended cold period leads to a peak gas demand of 2.7 BCF/day and extended demand during the coldest days in the winter.

This increasing peak reflects a challenge of relying on using natural gas to meet these peak requirements, particularly if there are pipeline constraints or high costs to securing firm pipeline capacity. Although the capacity expansion modeling includes cost adders to new natural gas plants to represent the cost of firm pipeline capacity to support new plants, this pattern of operations could suggest the need to offset gas use with other dispatchable resources, such as hydrogen or RE-CTs.

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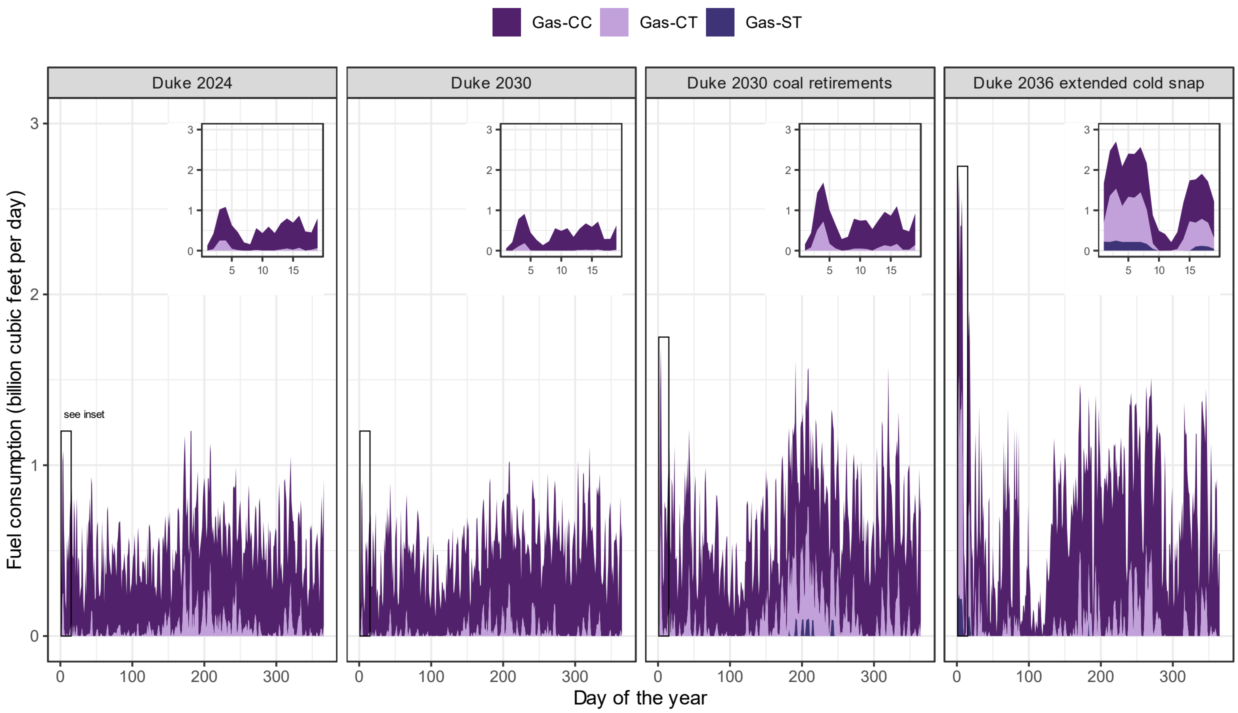

Figure 46. Total daily natural gas offtakes at Gas-CC, Gas-CT, and gas-steam turbines

The insets illustrate the daily gas demand in the first 2 weeks of January.

4.1.2 Energy Interchange

Figure 47 shows a time series of the net energy interchange between Duke Energy's service territory and neighboring regions, including Southern Company, PJM, and other balancing areas in South Carolina. Overall, the net interchange between Duke Energy and its neighbors doubles from the base case to the policy case. Much of this shift is driven by net exports, which reflect the value of exporting solar PV power when available; however, the extent to which neighboring systems adopt carbon reduction targets and integrate larger amounts of solar PV could reduce opportunities to use exports to balance solar PV in this way. Note also that although total imports remain similar across the base and policy cases, there is a general temporal shift toward having fewer hours of higher levels of imports. In addition, the weather year plays a strong role; in the accelerated coal retirement case with the 2012 profiles, the system uses imports more in the summer, whereas in the 2018 case, imports are more concentrated in the winter months.

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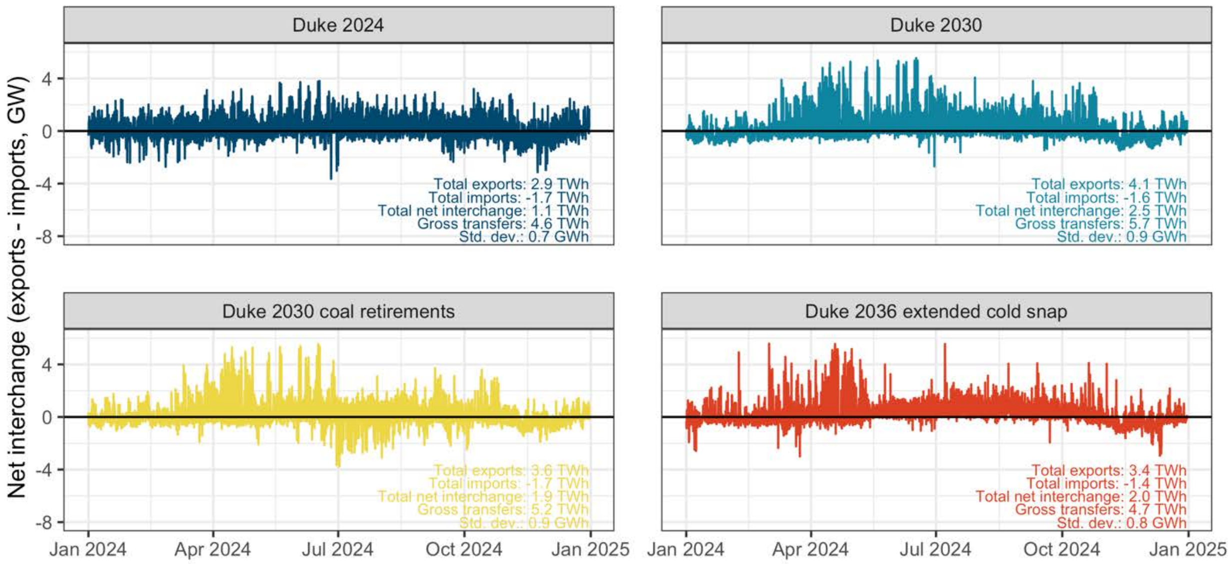

Figure 47. Total annual net interchange from Duke Energy to neighboring regions for the nodal cases

Positive values indicate exports from Duke Energy to neighbors, whereas negative hours indicate imports.

4.1.3 Variable Renewable Energy Curtailment

In discussing curtailment, note that curtailment can—and often does—provide economic value to the system. This analysis finds that the buildouts that achieve the policy targets and integrate higher levels of zero-carbon resources result in higher levels of curtailment. The capacity expansion model could have invested in additional storage to reduce some of this curtailment, but doing so was not the least-cost pathway identified by the model.

Figure 48 shows VRE total curtailment—both absolute level and as a percentage of available generation—across the nodal cases. As expected, the curtailment of VRE resources increases with higher levels of VRE contribution; for reference, the total VRE contribution is 12% in the base case (2024) and 24% in the policy cases (2030, 2030 + accelerated coal retirements, and 2036). Curtailment is primarily dominated by solar PV, but there is some curtailment from wind resources as well.

Finally, it is informative to explore the temporal pattern of curtailment, which we present using a curtailment duration curve in Figure 49. Moving from the base case to the policy case results in a doubling of curtailment in the peak curtailment hour—from 5 GW to approximately 8 GW 10 GW. In the 2036 policy case, the system experiences nearly 1,000 hours where instaneous hourly curtailment is 1 GW or greater.

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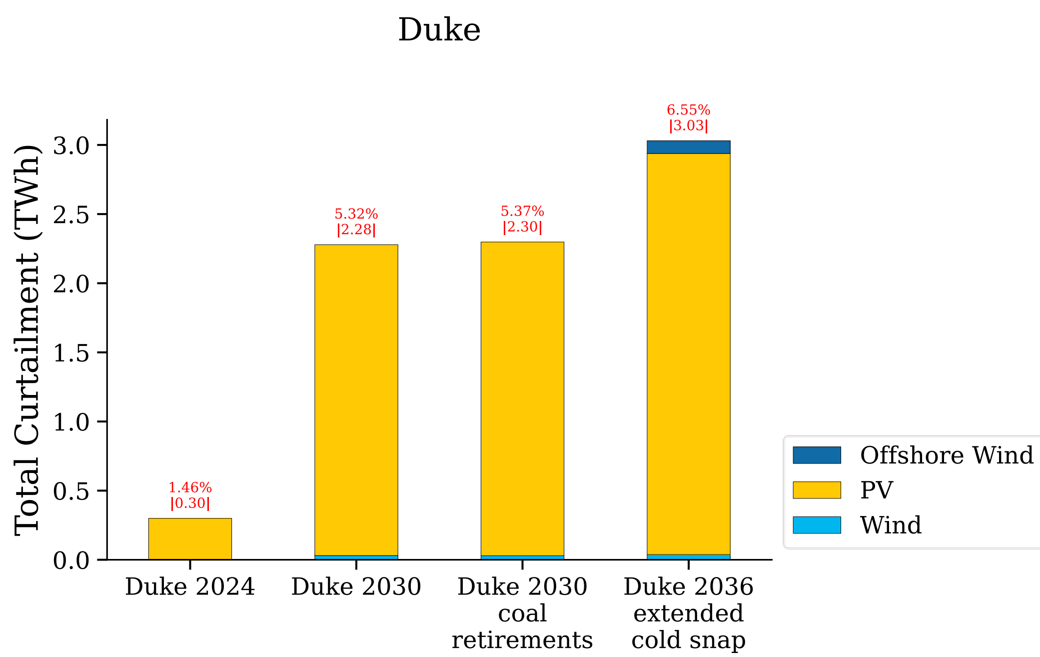

Figure 48. VRE total curtailment for the 2024 base case and 2030 case

The percentage values indicate the curtailment rate as a share of the available output, whereas the numbers between the bars reflect the magnitude in TWh.

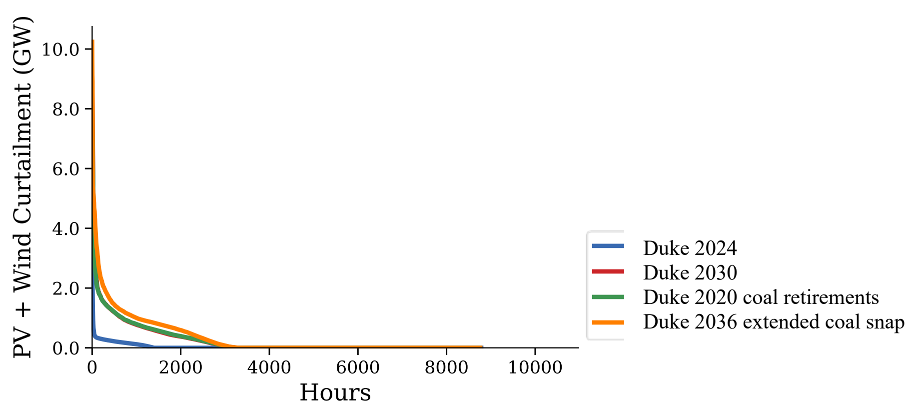

Figure 49. VRE curtailment duration curves for the nodal cases

4.1.4 Carbon Dioxide Emissions

Figure 50 and Table 9 describe the total annual CO_2 equivalent emissions in North Carolina in the base and policy cases based on operations in the production cost model. This includes direct emissions from Duke Energy power plants, emissions attributed to imported power,[16] and the CO_2 equivalent associated with methane leakage from natural gas use in the power sector. In all

[16] To attribute carbon emissions to imports, we compute the average emissions factor (total emissions per unit of generation) for every hour in the exporting region and multiply by the quantity of imports in that hour. We then sum across hours and exporting regions to calculate the total emissions attributable to imports.

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policy cases, North Carolina emissions fall below the policy target when considering direct emissions (i.e., excluding methane leakage).

Emissions reductions are largely driven by coal retirements and are partially offset by increased emissions from natural gas plants. Accounting for the emissions intensity of imported power becomes an important component, particularly in the 2030 policy case, where the emissions attributed to imports takes total emissions close to the target level.

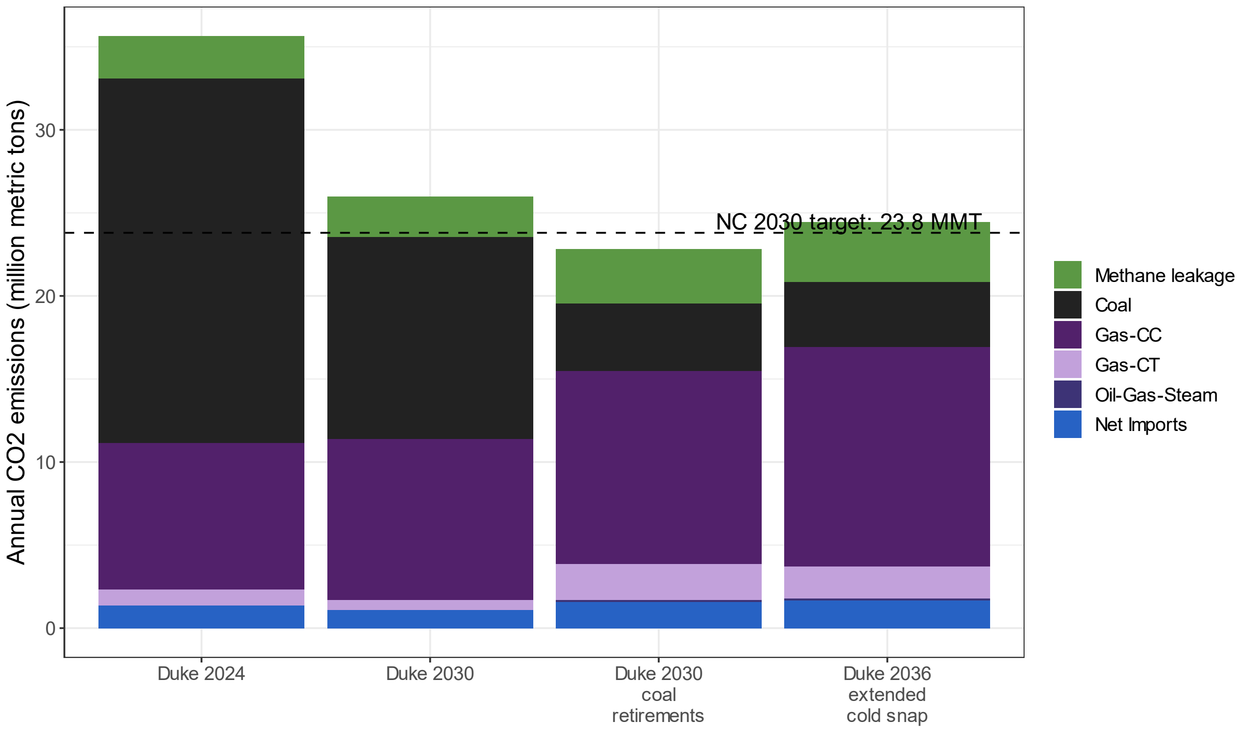

Figure 50. Total North Carolina CO_2 emissions in the base case and policy case, as estimated by the nodal production cost modeling

Emissions from power imported to North Carolina are accounted for using the carbon intensity of the exporting region on an hourly basis. The horizontal lines reflect the North Carolina emissions target of 23.8 MMT for 2030, a 70% reduction relative to 2005 levels. Note that this target and baseline might differ from values proposed by Duke Energy in the forthcoming Duke Carbon Plan.

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Table 9. Estimated Direct Annual Emissions (MMT CO_2) by Generating Technology

Emissions from imports are accounted for by computing the average emissions intensity in every hour of regions exporting to Duke Energy. The last row indicates the estimated change in emissions (%) relative to 2005 levels.

	Duke 2024	Duke 2030	Duke 2030 Coal Retirements	Duke 2036 Extended Coal Snap
Coal	21.9	12.2	4.1	3.9
Gas-CC	8.8	9.7	11.6	13.2
Gas-CT	1.0	0.6	2.2	1.9
Imports	1.36	1.08	1.57	1.66
Total	*33.1*	*23.6*	*19.6*	*20.8*
Decrease relative to 2005	*58%*	*70%*	*75%*	*72%*

Although natural gas combustion emits less CO_2 than coal, the methane in natural gas is also a potent greenhouse gas. Accounting for the climate impacts of fugitive, or "leaked," methane emissions thus becomes more important if the system incorporates more natural gas in the wake of coal retirements. Using a methane leakage rate estimate of 2.3% (Alvarez et al. 2018) and a 100-year global warming potential for methane (Pachauri and Meyer 2014), the CO_2 equivalent of fugitive methane emissions from natural gas consumption for power generation in Duke Energy's service territory ranges from 1.7–2.5 MMT.

For comparison, the North Carolina Department of Environmental Quality projects 1.5 MMT CO_2 equivalent in 2030 from all gas transmission and distribution systems; however, this estimate does not capture changes to natural gas use from meeting the 2030 policy target as modeled in this study, and it also employs a lower leakage rate of 1.4% (North Carolina Department of Environmental Quality 2022). As currently written, the North Carolina emissions targets focus on direct and indirect emissions and would not include upstream emissions from methane leakage.

4.1.5 Operational Costs

Generating costs—also referred to as operating costs—represent the costs associated with electricity production and thus do not include capital or investment costs. Figure 51 and Figure 52 depict the estimated total operational costs from the production cost modeling runs, broken out by cost type and by generator technology, respectively. Fuel costs represent the bulk of the operating costs in all cases, and although the increased integration of resources that do not consume any fuel reduces these costs in general, the heavy reliance on natural gas in the winter months for the 2018 weather case increases costs in that scenario. As Duke Energy continues to integrate additional low-marginal-cost resources, it can expect operating costs to continue to decline, although these costs savings should be considered in conjunction with higher capital and investment costs (discussed further in Section 4.2.5).

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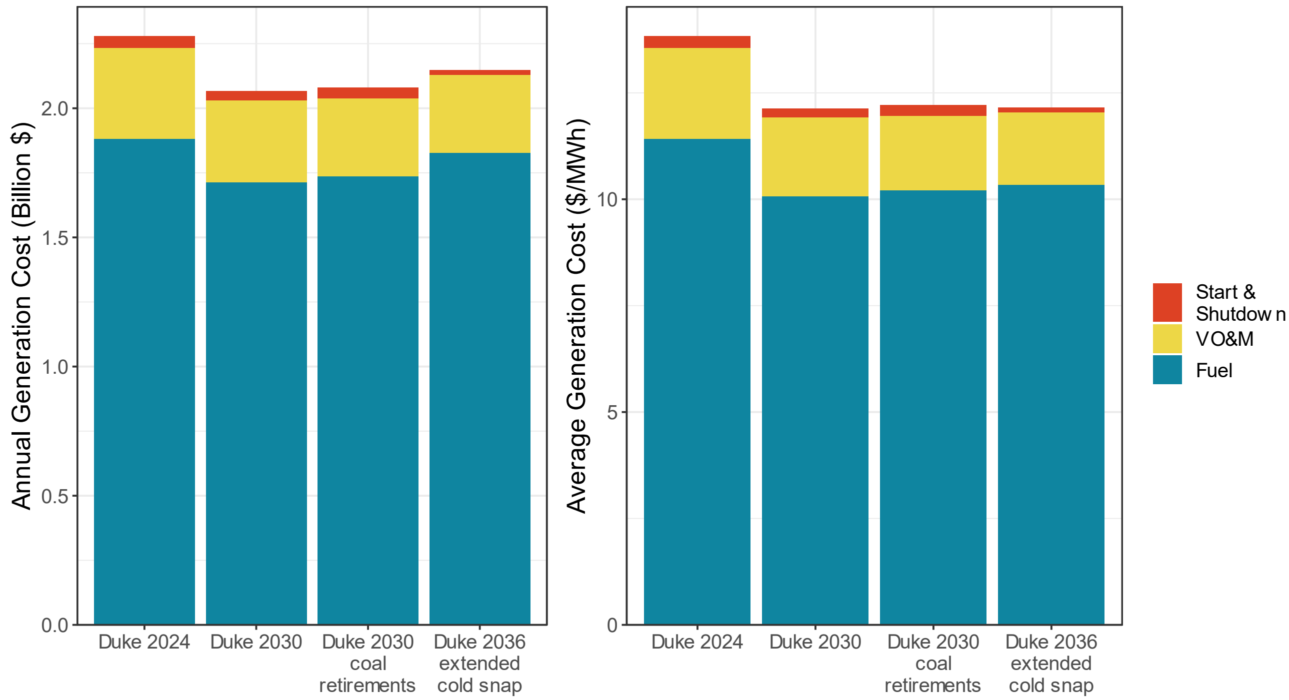

Figure 51. Annual generation costs for the nodal production cost modeling cases broken out by cost type

Generation costs are shown as totals ($U.S. billion, left panel) and normalized by load served ($/MWh, right panel).

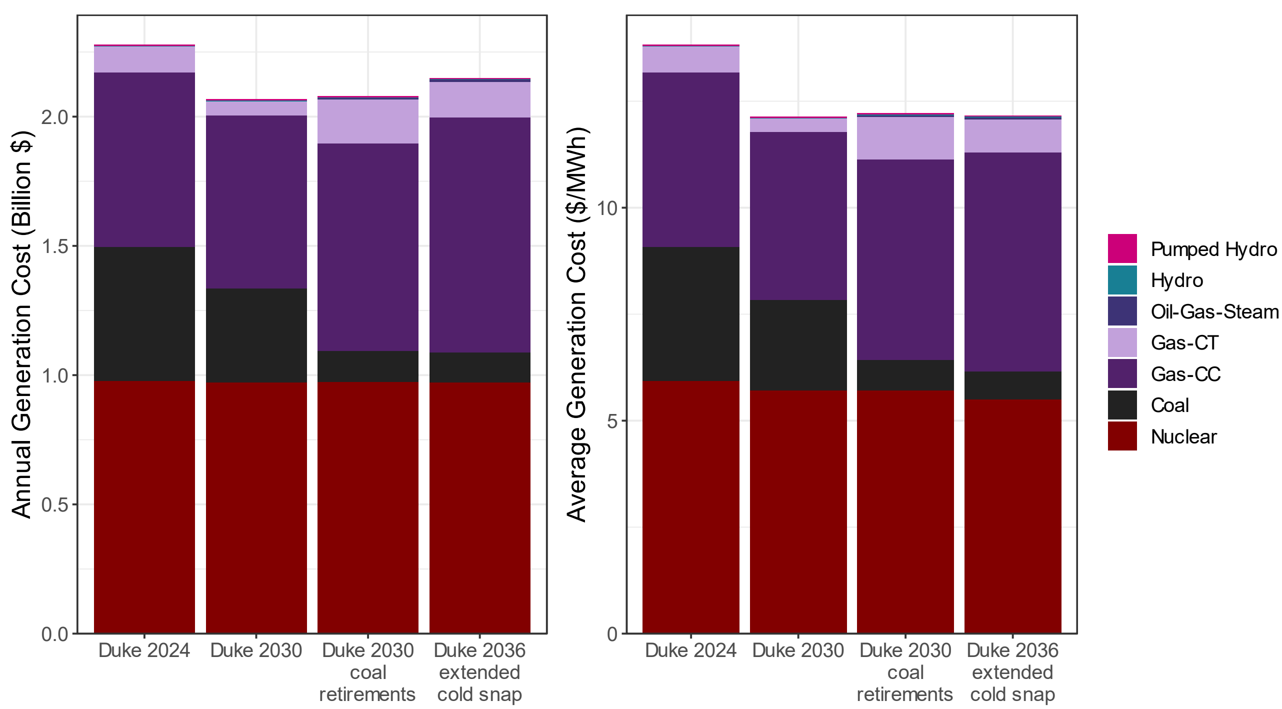

Figure 52. Annual generation costs for the nodal production cost modeling cases broken out by technology type

Generation costs are shown as totals ($U.S. billion, left panel) and normalized by load served ($/MWh, right panel). Note that these costs are not inclusive of investment costs.

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4.1.6 Operating Reserves

Operating reserves are pivotal for system operators to adequately respond to forecast errors and unplanned outages. The production cost modeling simulations in this study consider the co-optimized dispatch of generating units to provide both energy and operating reserves.

The operational model includes regulation reserves (to account for second-to-second and minute-to-minute changes in net load), flexibility reserves (to provide ramping needs related to variability and uncertainty in VRE resources), and contingency reserves (to respond to a major unit or transmission outage). The regulation reserve is estimated by using a 5-minute time step of load, solar PV, and wind profiles; 95% of the forecast error; and 1% load contribution. The flexibility reserve is calculated with a 60-minute time step of solar PV and wind profiles and an 80% confidence interval. The contingency reserve assumes 3% of the load with no consideration of wind or solar PV. Details of the methodology used can be found in our previous integration studies (Lew et al. 2013; Ibanez et al. 2012).

Figure 53 shows the total reserve provision by generator type throughout the year, and Figure 54 depicts a sample time series of reserve provision during the winter period. The total reserve requirement increases in the policy cases as load increases and as more renewable resources are integrated, in particular, solar PV. Much of this new reserve requirement is served by new battery storage, and storage also supplies additional reserves previously supplied by fossil thermal resources. The peak reserve requirement increases from approximately 4 GW to 6 GW in the winter period, and it shifts to the morning period when load increases but solar PV availability is uncertain.

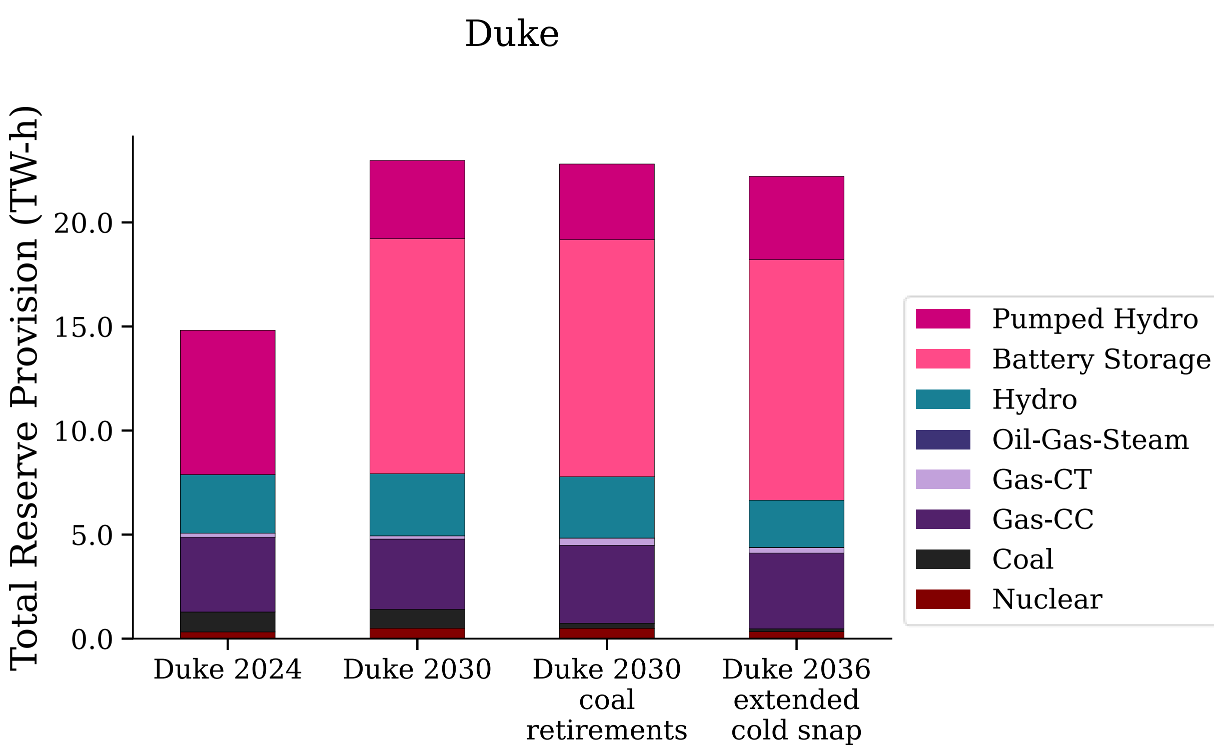

Figure 53. Total reserve provision in Duke Energy's service territory by generator type

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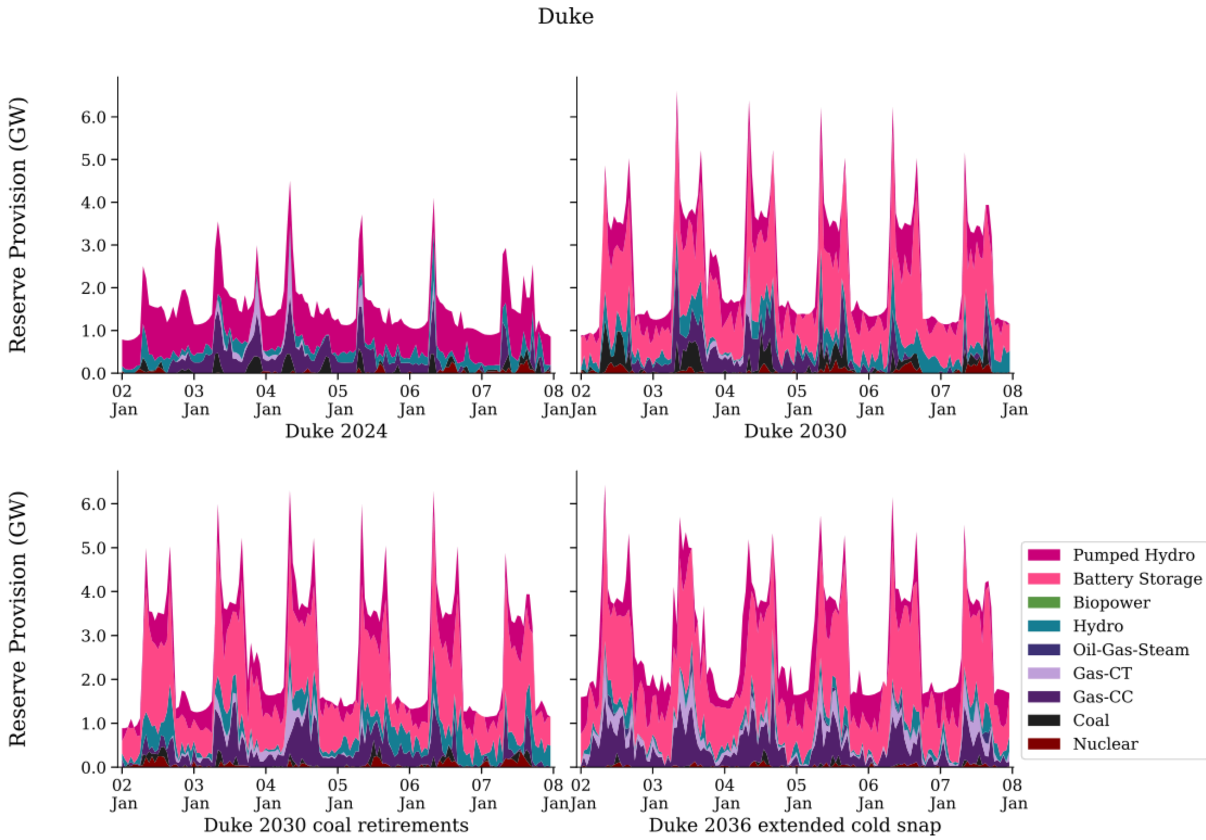

Figure 54. Reserve provision time series by generator type for Duke Energy's service territory

The time series shown is during the winter period of the highest reserve requirement.

4.2 Zonal Model

Because the ReEDS balancing areas do not neatly align with Duke Energy's territory, the zonal model primarily focuses on results for the Carolinas as a whole, with some discussion of results at the state or balancing area level where appropriate. Figure 55 provides the total installed generation capacity in the Carolinas in each of the three scenarios analyzed in the zonal production cost model: a 2024 base case that is used as a benchmark, the 2050 policy case, and the 2050 policy case in which all fossil fuel capacity in the Carolinas must be retired. These cases correspond to the core base and policy cases built by ReEDS in the first part of the analysis.

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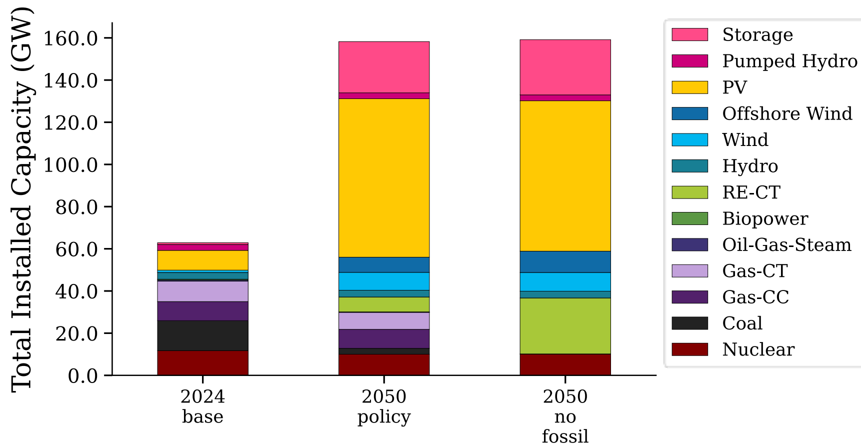

Figure 55. Total installed generation capacity in the Carolinas in each case used in the zonal production cost modeling

Here, *storage* refers to battery storage of various (2-, 4-, and 8-hour) durations.

4.2.1 Annual Generation and Dispatch

Figure 56 illustrates the total annual generation in the three zonal model cases. Higher annual generation in the 2050 cases reflects both growth in demand over time as well as increases in load driven by the need to charge storage devices. The policy cases result in large increases in generation coming from solar PV and wind to offset the reduced output from retiring coal and natural gas facilities. Although some coal remains outside of Duke Energy's system in the 2050 policy case in which fossil fuels are allowed to contribute to reserves, this coal is replaced by RE-CTs with the no-fossil fuel restriction.

Table 9 breaks down the contribution of each resource to total generation. Existing nuclear plants supply 26%–28% of the total energy requirement. Approximately 46% of the total annual generation in the Carolinas in the 2050 policy cases is provided by solar PV, with another 17%–23% provided by wind resources. It is notable that despite the relatively large amount of RE-CT capacity installed in the policy scenarios—7 GW in the policy case and slightly less than 27 GW in the policy case with no fossil fuels in the Carolinas in 2050—relatively little energy is supplied from these units, which provide only 0.3% of the total annual generation in the policy + no fossil scenario. This highlights the fact that these units are primarily needed to provide peaking power over a small number of hours and to meet firm planning reserve requirements.

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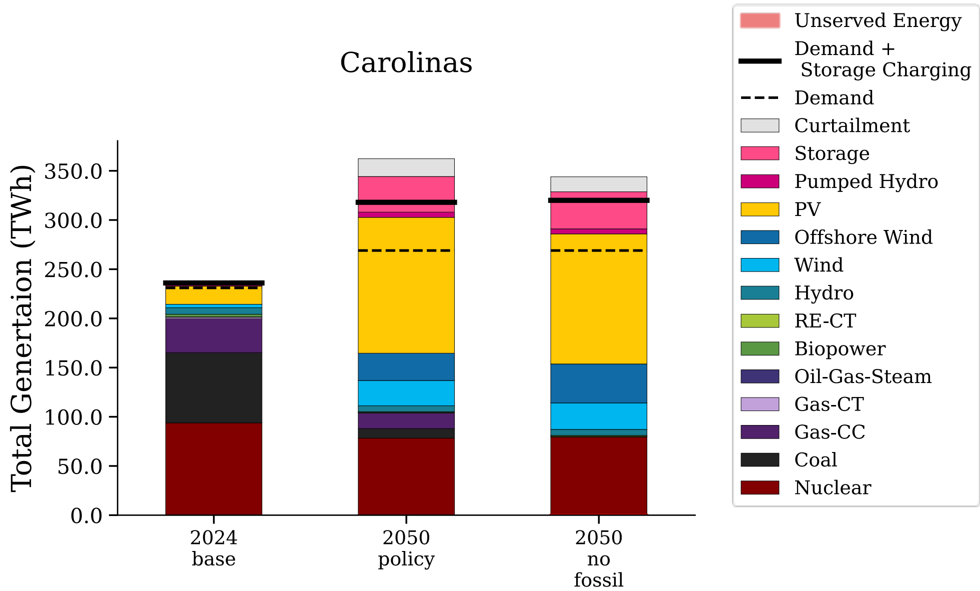

Figure 56. Total annual generation capacity in the Carolinas in each case used in the zonal production cost modeling

Table 10. Annual Generation by Year (Percentage of Total Generation Mix) in the Carolinas

Solar PV includes generation from utility-scale PV as well as distributed PV sources. Other categories include oil and gas-steam units, landfill gas facilities, and biomass. Note that the results are shown for both Carolinas; the Policy 2050 scenario gets to 100% carbon-free resources in North Carolina but does not eliminate all fossil resources in South Carolina.

	Base 2024	Policy 2050	Policy 2050 No Fossil
Nuclear	40%	26%	28%
Coal	31%	3%	-
Gas-CC	15%	5%	-
Gas-CT	1%	-	-
Land-based wind	2%	8%	9%
Offshore wind	-	9%	14%
Solar PV	8%	46%	46%
Hydro	3%	2%	2%
RE-CT	-	-	0.3%
Other	1%	0.2%	0.3%
Total carbon-free	53%	91%	100%

In addition to total annual generation, examining dispatch patterns during specific time periods can provide insight into system behavior. Figure 57 provides dispatch patterns for two critical periods: the hours surrounding the summer peaks and winter peaks; to see dispatch for all hours of the year, refer to the plots in Appendix B. In the summer, generation shifts from primarily a mix of nuclear, coal, and natural gas to nuclear, solar PV, and wind. During the day, excess solar PV generation is used to charge storage devices, which subsequently provide generation in the evening. In the 2050 policy case, overnight load is met with a combination of storage, wind, and some fossil fuel resources based in South Carolina outside of Duke Energy's footprint. In the 2050 policy case with fossil fuel retirements, this remaining fossil fuel generation is replaced by increased wind and storage as well as imports.

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The overall generation profile is similar during the winter period, but reduced solar PV output leads to increased reliance on imported power as well as generation from RE-CTs. Although sufficient RE-CT capacity is built such that the Carolinas would not need to rely on imports during the winter period, the high cost of these resources—which have fuel costs of $20/MBtu, or approximately $190/MWh after accounting for the heat rate of the RE-CTs—means that operational costs can be reduced through imports. If all imports were replaced by generation from RE-CTs, system costs would increase by close to $400 million annually in the policy case and close to $1.3 billion in the no-fossil fuel policy case.

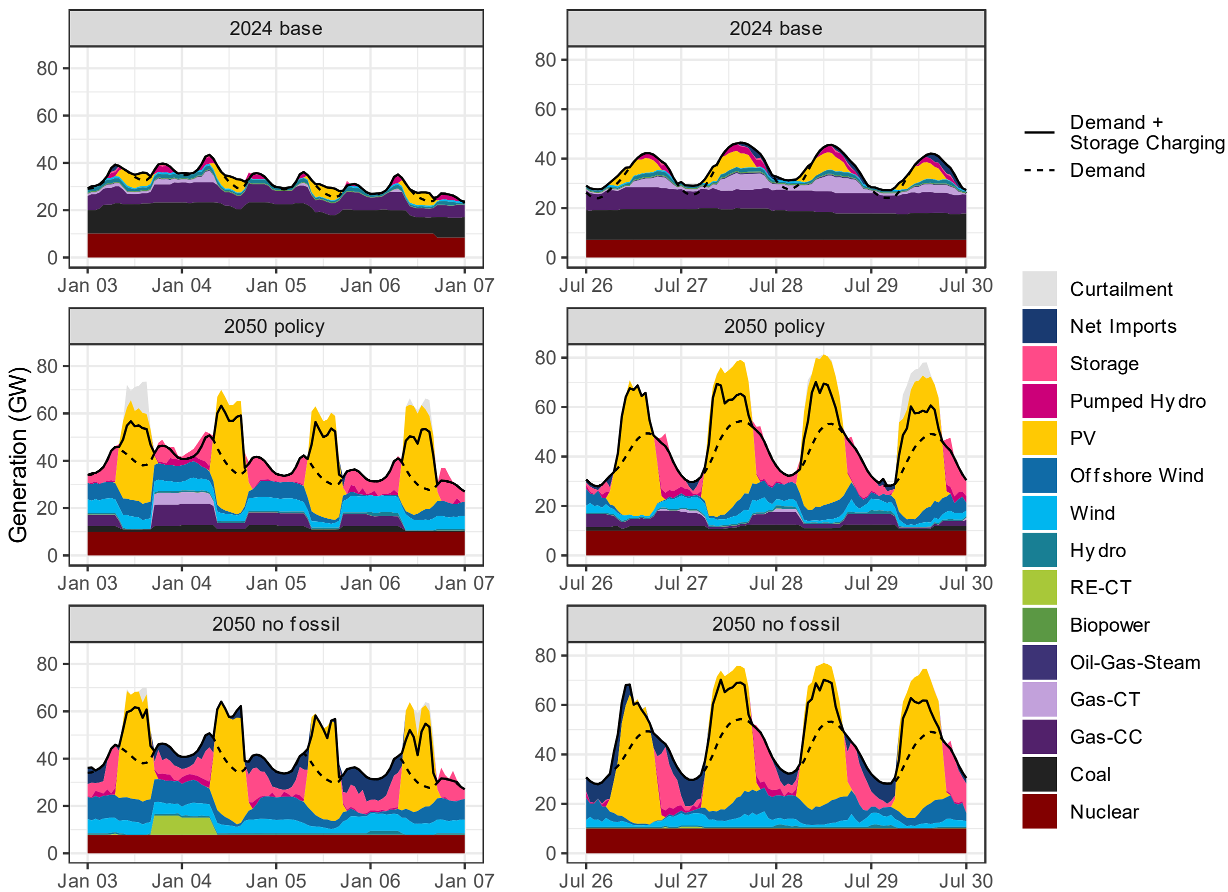

Figure 57. Generation dispatch for the 4 days surrounding the hour of net load peak in the winter (left) and summer (right)

For hourly dispatch results from the entire year, see the figures supplied in Appendix B.

Notably, the infrequent use of the RE-CTs in the no-fossil fuel policy scenario suggests that these firm capacity units could be supplied with fuel from a relatively modestly sized fuel storage. Figure 58 provides the daily fuel consumption of the RE-CT units; the longest contiguous fuel requirement is approximately 3 million MBtu, suggesting that a storage facility of that size would provide sufficient capability to operate those units during times of peak system demand. For context, a proposed liquified natural gas facility by Piedmont Gas in Robeson County, North Carolina, is expected to have a storage capacity of 1 million MBtu (Piedmont Natural Gas 2021). Note that this analysis estimates the minimum size of fuel storage necessary

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to sustain each peak and thus implicitly assumes that there is sufficient ability to replenish the storage in between uses. If fuel must be stored seasonally because of constraints on generation or transmission, then the required storage size would be larger.

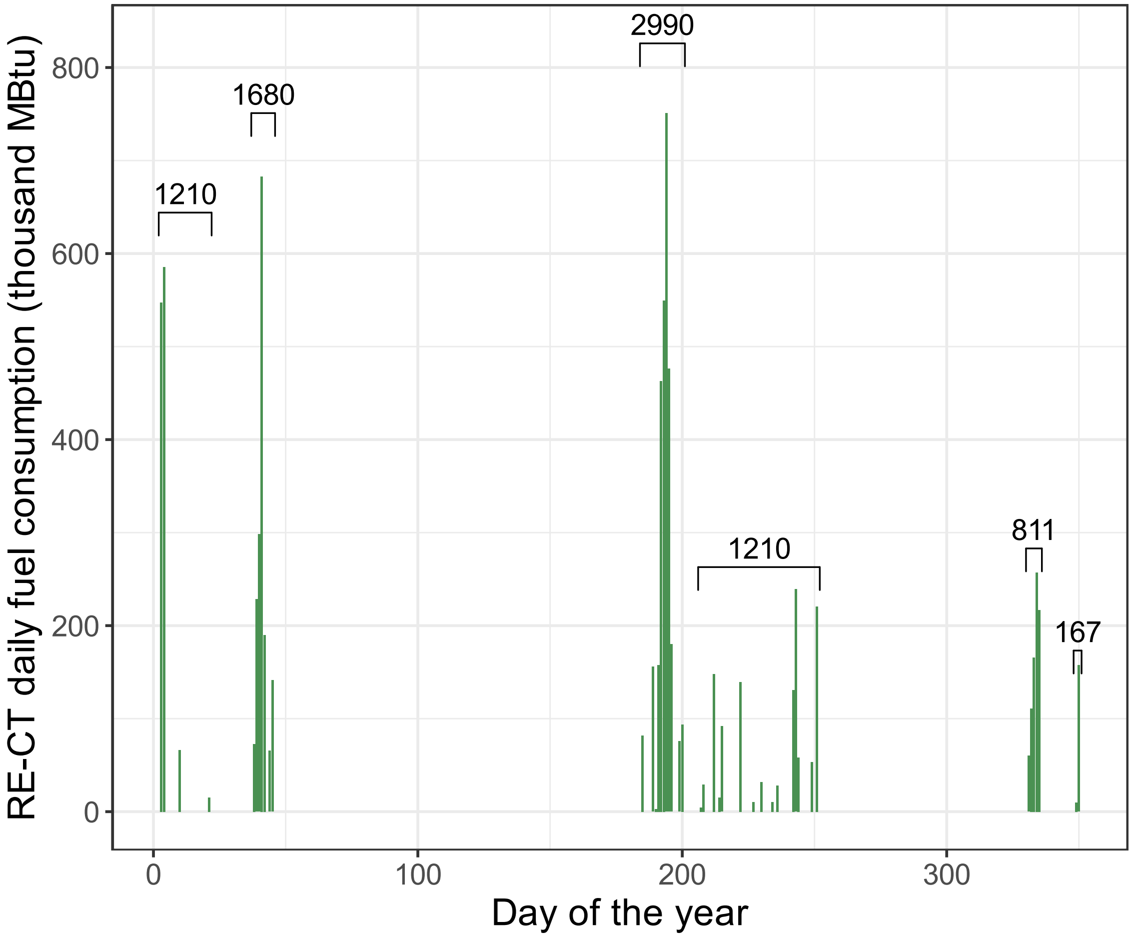

Figure 58. Total daily fuel consumption of the RE-CTs by day of the year (thousand MBtu per day)

Brackets indicate the total fuel consumption during important contiguous periods, suggesting the maximum size of renewable fuel or hydrogen storage that would be required to maintain these units.

4.2.2 Energy Interchange

As the Carolinas move toward a zero-carbon system, the higher levels of VRE sources on the system result in increased transfers of power with their neighbors. Figure 59 illustrates the net power flow between the Carolinas and the surrounding states. The figure illustrates a dramatic increase in the magnitude of the power flow between regions as well as the frequency of the power exchanged between regions. Two useful metrics in this space are net power exports (the total amount of power exports less imports) and gross power flow (the total amount of power transferred in either direction).

The power exchange between Georgia and South Carolina increases from almost nothing in the 2024 reference case (0 TWh net/0.2 TWh gross) to 10 TWh of net exports from South Carolina to Georgia in the 2050 policy case (13 TWh gross). Much of this exporting of solar PV from

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western South Carolina to Georgia occurs during times of excess generation. In the event that all fossil fuel in the Carolinas is retired, the net power exchange on this corridor is greatly reduced (0.2 TWh), although the gross exchange of power increases again (21 TWh). Similar increases are seen in the interface with Virginia, with net exports/gross exchanges increasing from -0.3 TWh net exports/0.6 TWh gross in the 2024 reference to 6–12 TWh net exports/14–19 TWh gross. The fact that gross power exceeds the net exchange in these cases indicates the value of the interface connections for helping to balance variability in VRE resources as the region moves toward higher shares of carbon-free generation.

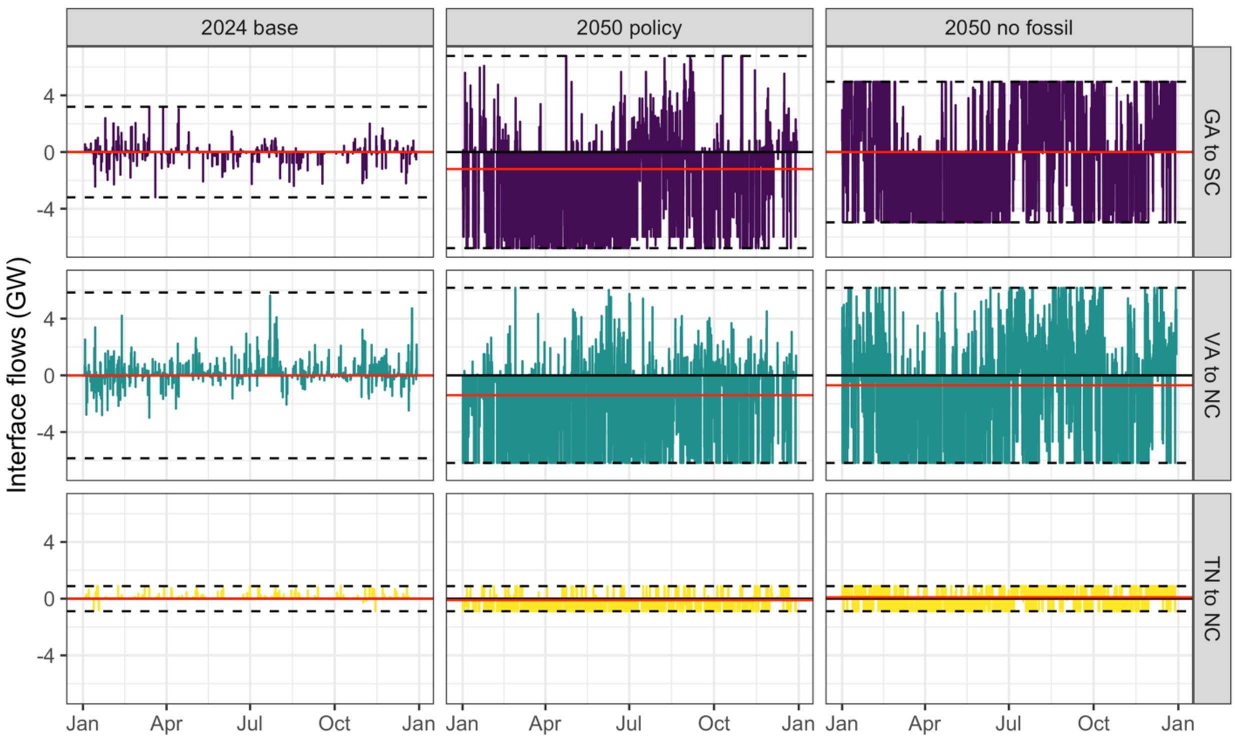

Figure 59. Net power flow (GW) between the Carolinas and its neighbors. Flows have been aggregated to the state level.

Positive flows indicate imports to the Carolinas (i.e., positive values on the "GA to SC" corridor indicate imports from Georgia to South Carolina). The red lines indicate mean flow value.

4.2.3 Variable Renewable Energy Curtailment

Figure 60 summarizes the total VRE resource curtailment from the zonal model. Curtailment—primarily from solar PV—increases dramatically in 2050, with approximately 18 TWh of curtailment (representing 8.6% of the available resource) in the policy case and 15 TWh in the policy + no-fossil fuel case (7.1%). Lower curtailment levels in the no-fossil fuel case likely reflect the additional storage capacity installed on the system to manage a system without any fossil fuel capacity backup.

Note that the 2024 curtailment estimates in the zonal model are zero, whereas curtailment in the 2024 nodal model was 0.3 TWh. This difference reflects the fact that curtailment can also be a result of transmission bottlenecks, which are more accurately captured in the nodal model. This suggests that the zonal model curtailment might be underestimated, although curtailment in high

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VRE systems is likely to be driven more by temporal mismatches in the load and resource availability than by transmission constraints (Frew et al. 2021).

As noted in the nodal model section results, increased curtailment reflects the outcome associated with the buildout chosen by the capacity expansion as the least-cost pathway to zero-carbon emissions. Additional investments in storage or transmission might help reduce some curtailment, but doing so would require additional investment costs.

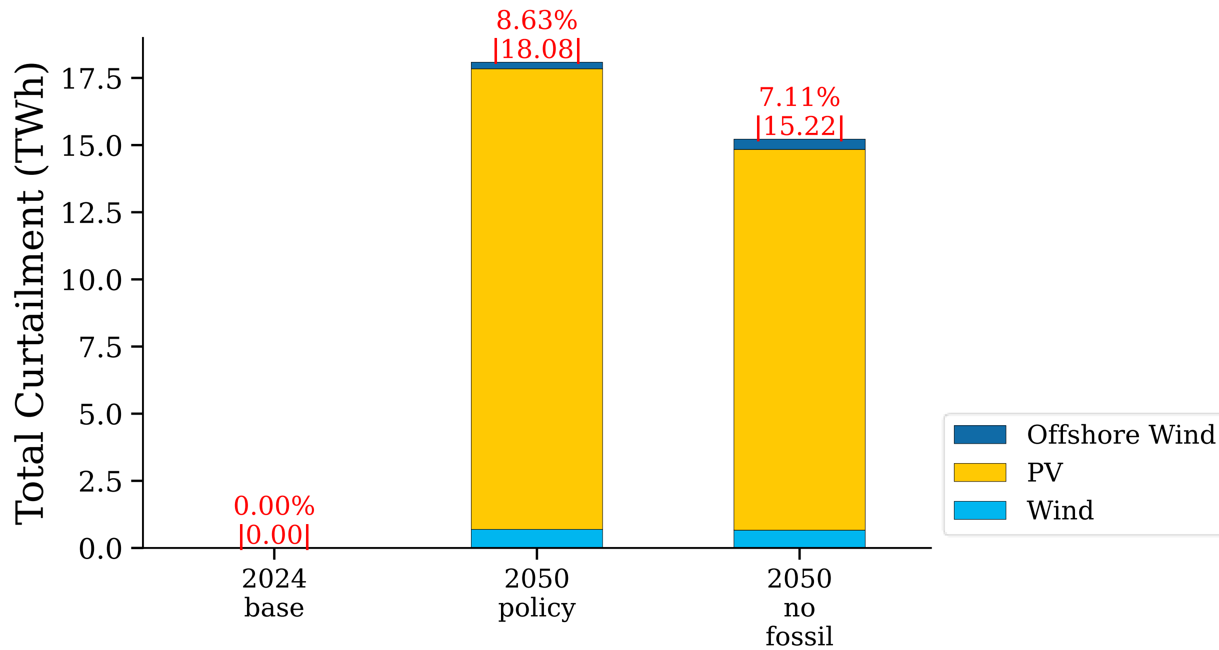

Figure 60. Total VRE curtailment for the zonal model 2024 base case and 2050 cases (policy and policy + no-fossil fuel requirement)

The percentages indicate curtailment as a share of total available resource.

4.2.4 Carbon Dioxide Emissions

Figure 61 depicts the total CO_2 emissions from the Carolinas under each zonal PLEXOS model case. Unlike in ReEDS—which models the emissions cap in North Carolina as a hard constraint—we allow the zonal PLEXOS model to dispatch whatever resources are available to understand how remaining fossil fuel resources might be used in the absence of a stringent policy requirement or carbon tax. The plot illustrates that the 2050 policy results in substantial CO_2 emissions reductions in both Carolinas, but in particular in North Carolina. In the absence of forcing all fossil fuel thermal plants to retire, the 2050 policy case results in some residual emissions from natural gas units that are infrequently used to balance load. These emissions are eliminated in the no-fossil fuel case, but some small emissions remain if accounting for the carbon intensity of imported power, following the same methods applied for estimate emissions from imported power in the nodal model. Although these are relatively small compared to the total reductions, they illustrate the importance of considering cross-border adjustments when moving toward a zero-carbon system.

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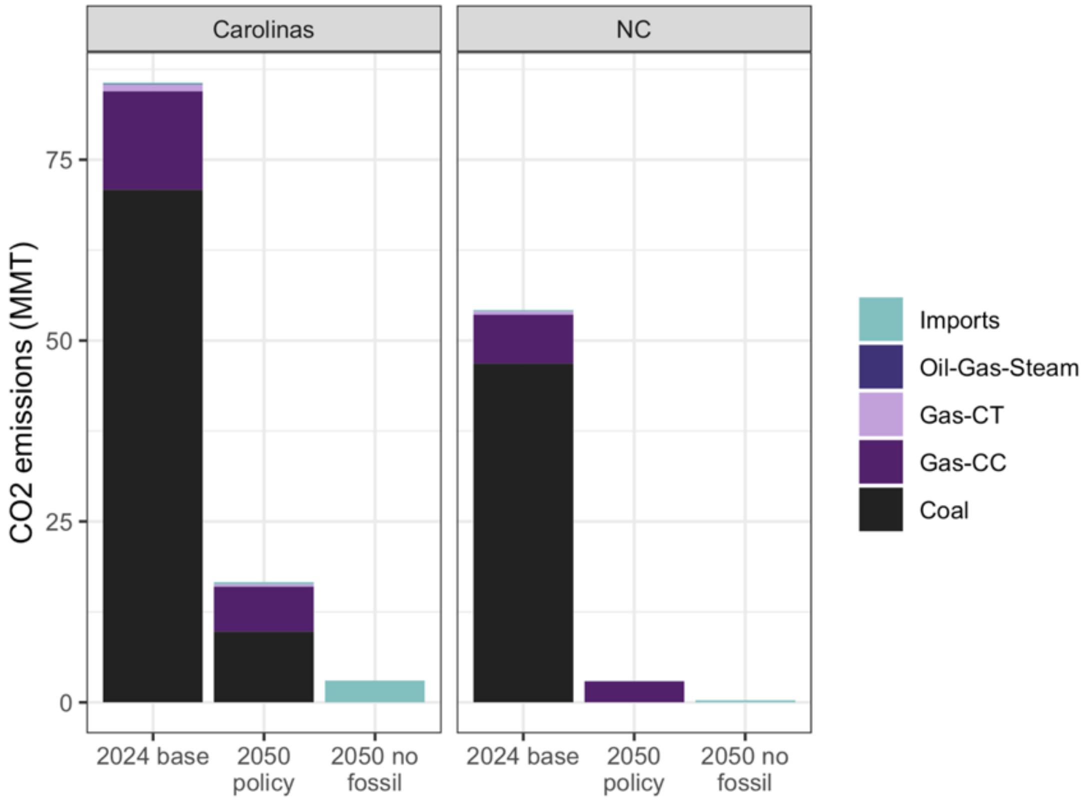

Figure 61. Total annual CO_2 emissions in the Carolinas (left) and North Carolina (right) under each case modeled in PLEXOS

4.2.5 Operational Costs

Figure 62 provides the total annual operational cost as estimated from PLEXOS, both by cost type and technology. As the system adopts traditionally low- or zero-marginal-cost resources, the annual operating cost declines. Declining operational costs are, however, accompanied by increased capital costs, particularly as more resources are needed to meet firm capacity needs when reducing the last 5%–10% of CO_2 emissions from the system. The shift from operational to capital costs is emphasized in Figure 63, which shows the annualized investment costs in 2050 from ReEDS for the base and policy scenarios. The plot illustrates the shift from operational to investment costs. In addition, the figure estimates the net cost of electricity trade (the cost of import less the revenue received from exports),[17] which increases as the system increasingly exchanges power with its neighbors to help balance variability from high levels of VRE.

[17] Costs and revenues from power exchanges are based on the clearing price of electricity between regions in the hour of interchange. In addition, the $10 hurdle rate is accounted for in the cost of imports.

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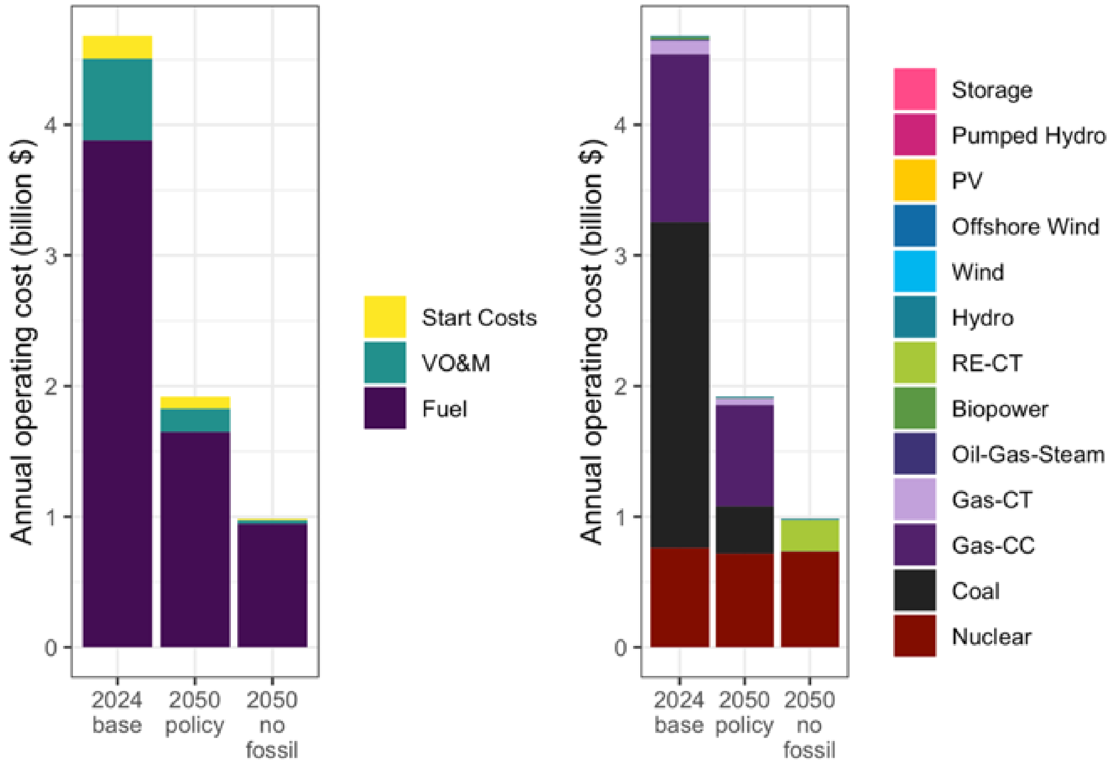

Figure 62. Annual operating costs (2020 $U.S. billion) for each of the three zonal model cases. Costs are broken down by cost type (left) and generating type (right).

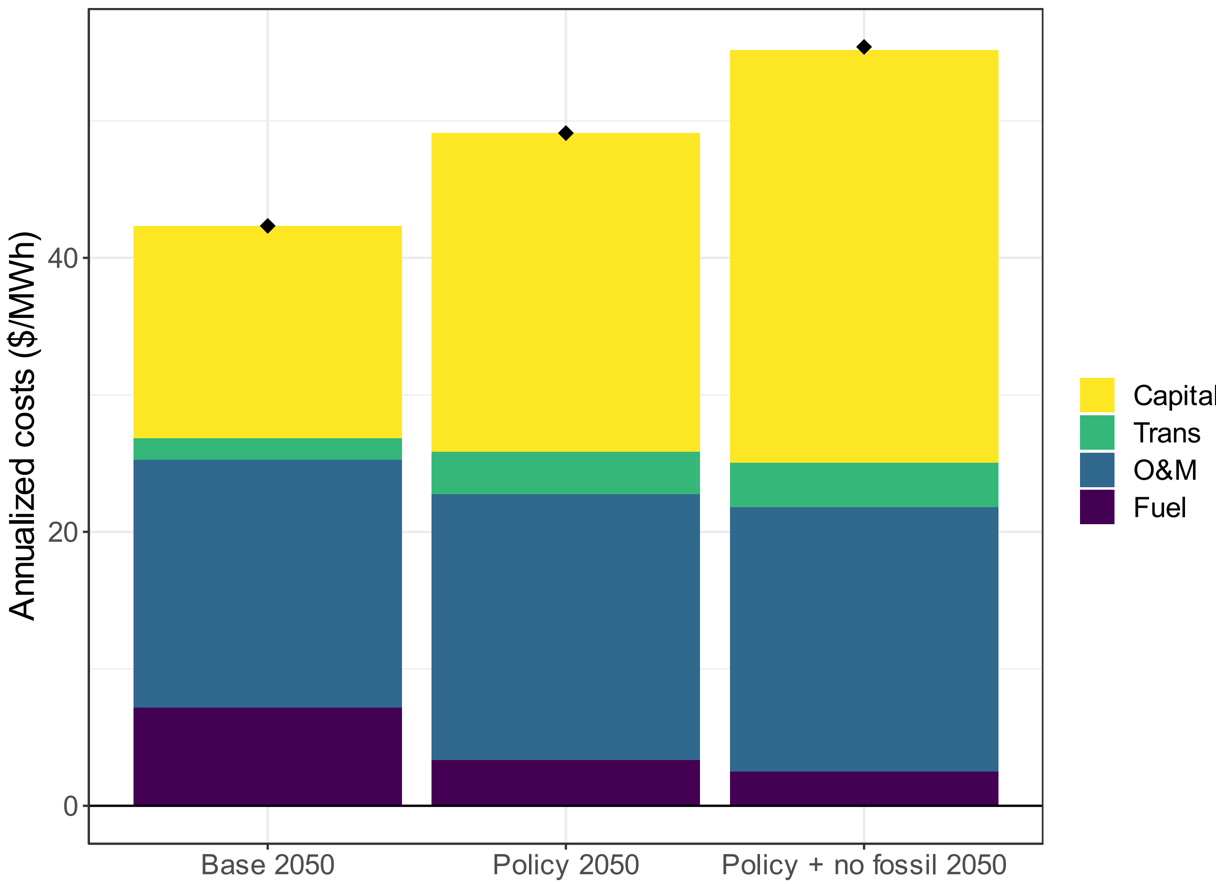

Figure 63. Total annual system costs (U.S. 2020 $/MWh) for the 2050 zonal model cases.

Cost estimates summarize the annualized capital cost accounting from ReEDS, with the Base 2050 cost estimates provided for comparison. Note that these estimates do not include costs for imported power.

4.2.6 Operating Reserves

Reserve requirements in the zonal PLEXOS model are aligned with the settings in ReEDS. There are three reserve products in the zonal model formulation: spinning (contingency), regulation, and flexibility. Requirement fractions for each product are presented in Table 11 and are based on estimates from previous studies (Lew et al. 2013; Brown et al. 2020).

Table 11. Reserve Requirement Levels by Product

Wind requirements are the percentage of generation, whereas PV requirements are specified as the percentage of installed capacity.

	Load	Wind	PV
Spinning	3%		
Regulation	1%	0.5%	0.3%
Flexibility		10%	4%

Figure 64 illustrates the total annual provision of reserves by generating technology, and Figure 65 plots reserve dispatch during the winter period examined earlier. Two important shifts are notable. First, there is a dramatic increase in flexibility reserve requirements as more VRE generation resources are added to the system. Second, although most reserves in the 2024 reference case are served by fossil thermal resources and hydropower, in the 2050 cases, the bulk of the reserve provision is supplied by battery storage. The reliance on storage for almost all reserves suggests the need for careful coordination to ensure sufficient state of charge to supply reserves as needed. Although RE-CTs provide low levels of total operating reserves—likely because of their relatively high operating costs compared to alternatives—they are used during key periods of tight conditions in the winter.

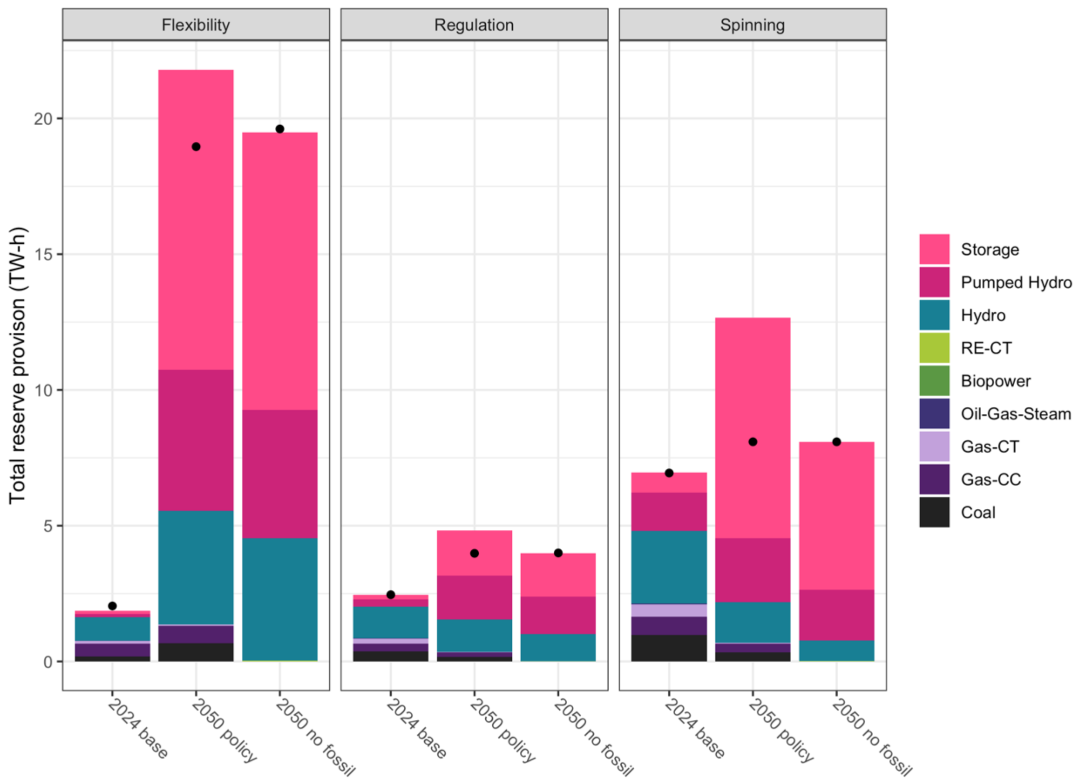

Figure 64. Total annual reserve provision by technology type and reserve product

The dots indicate the total reserve requirement for each case. Note that in some cases PLEXOS can over procure reserves.

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Figure 65. Total reserve provision by technology type and reserve product during the winter peak period

The solid lines indicate the total reserve requirement in each hour for each case. Note that in some cases PLEXOS can over procure reserves.

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5 Summary of Findings

This study explores the opportunities and challenges for Duke Energy to integrate carbon-free resources into its Carolinas service territory. The analysis focuses on both an intermediate target—achieving 70% CO_2 emissions reductions in North Carolina relative to 2005 levels—as well as a zero-emissions target. The pathways to achieving these targets are examined using a multi-model approach that includes the assessment of wind and solar PV resources in the Carolinas, capacity expansion modeling of the least-cost investment portfolio to achieve the targets, and, finally, production cost modeling on a subset of the investment buildouts to further evaluate their operational performance.

The following paragraphs summarize some key findings of the study.

Finding 1: Duke Energy can meet the 2030 emissions target in North Carolina through investments in a combination of solar PV, wind, and energy storage along with maintaining its existing nuclear fleet. When considering only direct emissions, all the nodal modeling cases fall below the 2030 emissions target, although the exact emissions level depends on the scenario evaluated. For example, using the alternate load and weather profiles with the extended winter cold period results in higher emissions than under the baseline assumptions.

Accounting for emissions from imports might become increasingly important as Duke Energy increases interchanges with its neighbors. The magnitude of the emissions depends on the emissions intensity of imports, which is likely to change depending on additional policies enacted in the surrounding regions. Although the North Carolina policy does not include upstream emissions, we include estimates for the effects of methane leakage, which, under standard assumptions, would add approximately 1.7–2.5 MMT of CO_2 equivalent.

This emissions estimate is in line with estimates of reductions in the policy scenarios from Duke Energy's modified IRP as well as estimates from an independent study of policy options for reducing emissions in North Carolina (Konschnik et al. 2021; Duke Energy 2021). By 2030, 75% of the total annual generation will come from carbon-free energy resources (wind, solar PV, and nuclear), with 23% of generation coming from variable generation sources.

Operational modeling of the ReEDS buildout for the 2030 policy case shows that the system is able to supply generation to meet load in all hours for a normal weather year as well as for a year with an extended cold snap that includes a sustained period of high load and relatively low solar PV output. Note, however, that although the modeling approach implemented accounts for the need to hold operating reserves to manage contingencies and other events, the analysis does not explicitly simulate contingencies or transient stability, and future work might consider these aspects.

Approaching the 2030 target requires a substantial reduction in the share of generation provided by Duke Energy's coal fleet. The reduced generation from coal largely comprises increased generation from solar PV, wind, and energy storage. Natural gas contributes to meeting this goal as well—particularly by supplying generation during times of low wind and solar output, such as during the winter peak, and ramping to balance solar PV.

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Sensitivities to different VRE cost trajectories or technology developments, coupled with the value of resource diversity as the system achieves its interim target and moves toward zero-carbon emissions, suggest that there are benefits to early investments in a range of technologies. Both land-based and offshore wind provide complementary generation to solar PV, adding value toward meeting planning and operational requirements during times when solar PV has low availability. Similarly, research and planning options for clean firm capacity and energy storage of different duration levels should begin early to ensure that these resources can be integrated into the grid to achieve zero emissions. The cumulative cost of CO_2 abatement for the interim 2030 target is approximately $7/metric ton (ranging from $6–$20/metric ton across key sensitivities). The relative low cost of CO_2 to meet the interim targets demonstrates that Duke Energy has several cost-effective options for reducing CO_2 emissions.

Though the capacity expansion and operational modeling indicate that the 2030 North Carolina emissions target is feasible from an operational perspective, note that these models do not capture all the challenges inherent in building transforming the system to achieve that target. For example, ReEDS does not consider supply chain or workforce limitations, interconnection process or permitting requirements, the time needed to allocate funding for new construction, or the need to construct intra-regional transmission to support new generation capacity. Such constraints might increase the cost and time required to achieve the pathways recommended by the modeling for achieving the carbon emissions reduction target.

Finding 2: A zero-carbon emissions electricity sector target in 2050 can be achieved through investments in solar PV and battery energy storage, coupled with maintaining the existing nuclear fleet, building land-based and offshore wind, and procuring other zero-carbon emissions resources that supply firm capacity. From a generation scheduling perspective, the zero-carbon buildouts tested in PLEXOS for this study were able to serve load in all hours. The average cost of CO_2 abatement in the Carolinas through 2021–2050 ranges from $27–$33/metric ton (ranging from $9–$34/metric ton across key sensitivities).

Eliminating the last 5%–10% of CO_2 emissions from the power system presents new challenges and obstacles relative to the first 90%–95%. One key challenge is meeting planning reserve requirements—or, in other words, ensuring that sufficient generating capacity is always available to meet load. Moving closer to zero-carbon emissions requires increasingly large amounts of VRE sources to offset retiring firm capacity as the value of new VRE declines and requires longer-duration storage to shift available energy to times of the day with lower VRE output (evening, overnight, and morning) or to sustain generation during extended (multiday) periods of low VRE resource. A reflection of the increasing challenge to eliminating the last tons of CO_2 from the system is the fact that the average *incremental* cost of CO_2 emissions abatement increases from approximately $40/ton in 2048 to $75/ton for the policy case and $97/ton for the no-fossil fuel case in 2050, when the zero-carbon requirement in North Carolina is enforced.

Addressing the planning reserve challenge posed by the last 5%–10% CO_2 emissions reductions needed to get to 100% carbon-free generation is facilitated by the availability of firm capacity, zero-emissions resources. The modeling in this study primarily deploys RE-CTs to meet this need, but this technology could be any firm, zero-emissions generation opportunities, including combustion turbines fueled by hydrogen, small modular nuclear reactors, shifting of VRE generation using seasonal storage, or demand response. A challenge of providing this capability is that these resources—though essential for ensuring reliability given the variability and uncertainty of VRE generation—are likely to have low capacity factors. As a result, technologies with low capital costs will be more competitive in providing such services than their higher capital cost counterparts, even if those more capitally intensive resources have low operating costs.

Advancements in reducing the capital cost of these resources will play a large role in reaching a 100% carbon-free target. The requirements for firm zero-carbon resources—along with higher levels of VRE and longer-duration diurnal storage—increase the cost of mitigation relative to the first 90%–95% of carbon emissions reductions.

Achieving a zero-carbon system requires a large buildout of new technology, with the installed capacity of Duke Energy's power system increasing by more than 1.5 times its current size, faster than the growth rate of load. Although a higher level of installed capacity is not problematic from a power system operation standpoint, achieving this buildout might pose logistical challenges in siting, interconnecting, and constructing new generation capacity that need to be addressed.

Although most of this new capacity comes from technologies that are currently available, some includes relatively novel technologies that are not yet deployed at scale, such as RE-CTs, which might also require investments in supporting infrastructure to deliver the zero-carbon fuel. Continued technological advancements and cost declines are likely to prove pivotal to enabling these pathways. Further, as noted previously, the modeling in this study does not consider the investments or policies needed to ensure sufficient supply chain and workforce capability to achieve these builds, and planning to achieve a zero-carbon system must consider these elements as well. More work is needed to understand the operations of a zero-carbon system from the standpoint of transient/dynamic stability, contingencies, and extreme weather events.

Finding 3: Investments in new transmission and expanded power exchange with neighbors can play an important role in achieving both the 2030 target and a net-zero power system. Through 2030, the capacity expansion modeling prescribes an additional 2.8 GW of interface transmission in the Carolinas under the policy target and almost 12 GW of new capacity through 2050. Although the policy scenarios result in increased interface transmission buildout relative to the reference case, the reference scenario also invests in new transmission through 2030 (1.6 GW) and 2050 (7.2 GW). This outcome reflects the fact that there are sizeable "no regret" transmission investments that have high value under a range of policy outcomes. Important corridors for investments through 2030 include between eastern and western North Carolina and between western North Carolina and South Carolina. By 2050, however, nearly all routes show increased investments to manage increased power exchange.

Expanded transmission—both within Duke Energy's territory and with its neighbors—reflects the fact that increased coordination with neighbors is likely to facilitate the integration of high levels of wind and solar PV as Duke Energy meets the 2030 policy target and moves toward a zero-carbon system by 2050. Operational modeling simulations show that transfers between Duke Energy and its neighbors increase in both frequency and magnitude as the share of VRE increases. The increased energy and capacity exchanges associated with a low- or zero-carbon emissions power system can reduce the challenges of balancing a high VRE system and reduce

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the costs. Sensitivities evaluating the adoption of zero-carbon targets in neighboring regions or greater regional coordination for meeting firm capacity requirements indicate less need for RE-CTs in the Carolinas but also more adoption of offshore wind and longer-duration storage. At high contributions of carbon-free resources, accounting for the emissions intensity of imported power plays an important role in understanding the system's carbon footprint. New policies that facilitate the coordination and transmission cost allocation across load-serving entities are likely to be an important enabler of the higher levels of power exchange between Duke Energy and its neighbors that are envisioned in this study.

Finding 4: Flexible, zero-emissions technologies that can provide firm capacity are a critical component to meeting peaking needs not only in the summer but also, increasingly, in the winter as well. Duke Energy is already a dual-peaking system in that it experiences both a summer and a winter peak. As Duke Energy moves toward higher levels of carbon-free resource integration, however—including higher levels of solar PV and energy storage—the period of greatest system stress is likely to continue to shift to the coldest winter mornings, and this trend could be exacerbated by the potential electrification of space heating or electric vehicle adoption.

With higher shares of wind and solar PV, operating reserve requirements become increasingly focused on managing the variability and uncertainty associated with VRE resources. Energy storage is increasingly used to provide operating reserves, suggesting the importance of proper planning to ensure that sufficient state of charge is available to provide reserves or to meet winter peak requirements. Under this study's assumptions, firm capacity resources that operate at low capacity factors play an important role in meeting demand and operating reserves during the winter peaking period.

Importantly, the capacity expansion and production cost modeling in this analysis focus on a single, relatively normal weather year. Understanding the least-cost buildout and operational performance under a range of weather conditions is an important component to fully understanding the capability of these low- and zero-carbon power systems, and future analyses will focus on performance assessments under different weather conditions.

Finding 5: As Duke Energy transitions to lower-carbon generation resources, it can expect the capital share of total bulk system costs or expenditures to increase while the operational share decreases. With the retirement of fossil fuel resources and their replacement with low- or zero-marginal-cost resources, operational costs from fuel and variable operation and maintenance are likely to substantially decline; however, the declining value of VRE resources at higher shares and the subsequent need for firm clean capacity—including some resources that have very low utilization—suggest increased capital expenditures. In addition, increased trade with neighboring regions could imply higher costs related to importing firm power. Importantly, the cost estimates in this study include only bulk system costs and thus do not account for costs from distribution systems, energy-efficiency or demand response programs, administrative costs, or servicing existing debt.

As with other decarbonization studies, note the limitations implicit from the analytical approach as well as how those limitations shape the appropriate interpretation of the results. For example, this study does not consider several important planning aspects, such as AC power flow, dynamic or transient stability, contingency analysis, or nodal transmission expansion. The

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findings of this study point to an optimal power system design for balancing generation with load and for meeting other system planning constraints, but more analysis is needed to understand how such a system would operate and what transmission and distribution system investments are needed to manage it. As such, the results of this study are not intended to supplant Duke Energy's traditional planning process and should not be considered a substitute for Duke Energy's IRP process.

Although this study assesses the capacity buildout pathway to achieve the stated policy objectives, it does not attempt to evaluate the logistical feasibility of those pathways. Large amounts of new generation capacity are built to meet both the interim and zero-carbon targets; this study does not assess potential supply chain or labor force constraints in achieving those buildouts, and though it accounts for the cost of interconnection and related grid upgrades to adopt those resources, it does not explicitly model the timing for completing those upgrades.

With a substantial amount of clean energy currently generated by nuclear, along with strong solar PV resources, Duke Energy is well positioned to move toward higher levels of carbon reduction. Achieving the interim target will require some additional investments and new capacity over the base case and will also require moving away from using Duke Energy's subcritical coal units, but it can be accomplished with technologies that are currently commercially available. Full decarbonization beyond 90% is more technically challenging; diversity in generation resources and improvements in the cost and operational characteristics of firm, carbon-free technologies become increasingly valuable for removing the last few tons of CO_2 emissions from the system.

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Appendix A: Resource Assessment Details

Table A-1 and Table A-2 present assumptions for the Renewable Energy Potential (reV) analysis of this study for utility-scale solar and wind, and Figure A-1 provides the power curves used for land-based and offshore wind. These assumptions are based on the default value suggestions from the reV documentation (Maclaurin et al. 2019).

Table A-1. Utility-Scale Solar Configuration Assumptions for reV

	Baseline
Array type	1-axis tracking
Azimuth (degrees)	180
Tilt (degrees)	0
DC/AC ratio	1.3
Ground cover ratio	0.4
Inverter efficiency (%)	96
Losses (%)	14.1

Table A-2. Wind Configuration Assumptions for reV

	Land-Based Wind		Offshore Wind	
	Baseline	Advanced Sensitivity	Baseline	Advanced Sensitivity
System capacity (MW)	2.3	5.5	6.0	15
Hub height (m)	110	120	100	150
Rotor diameter (m)	113	175	155	240
Losses (%)	16.7	11.8	16.7	16.9

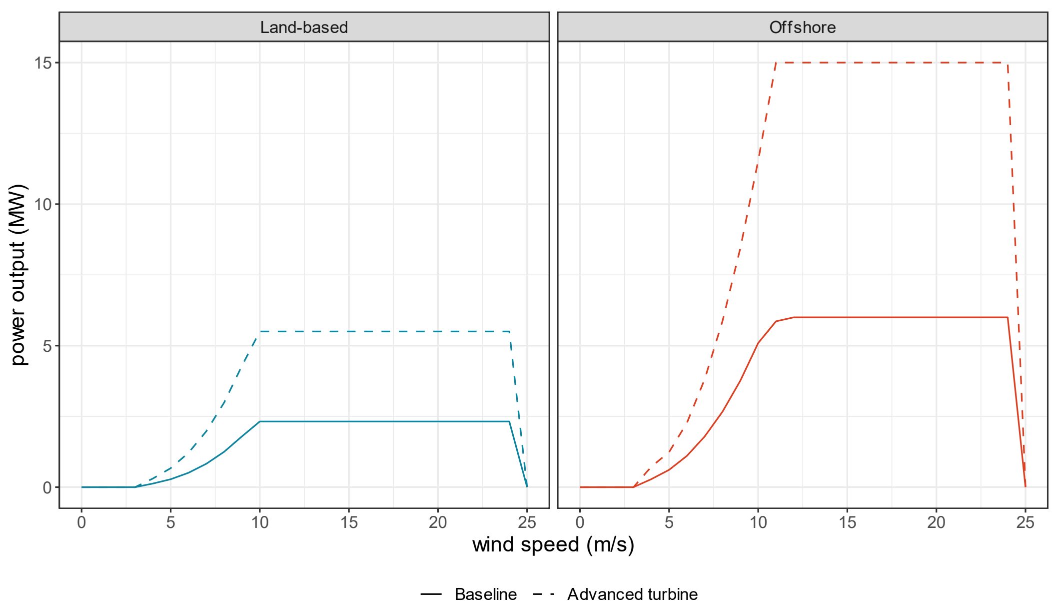

Figure A-1. Wind power curves for land-based and offshore turbines under the baseline and advanced turbine technology assumptions

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Table A-3. Land-Based Wind Supply Curve Quantities from the reV Analysis

Wind Class	Avg. Wind Speed (m/s)	Total Supply Curve Capacity (GW)		
		Baseline	Advanced Turbine	Limited (Line-of-Sight Radar Exclusions)
1	> 9.01	-	-	-
2	8.77–9.01	-	-	-
3	8.57–8.77	-	-	-
4	8.35–8.57	-	-	-
5	8.07–8.35	-	44	-
6	7.62–8.07	34	543	6
7	7.10–7.62	890	4,113	77
8	6.53–7.10	9,043	14,610	2,379
9	5.90–6.53	25,044	23,148	2,109
10	0–5.90	39,636	16,806	5,306
All classes	-	74,648	59,265	9,876

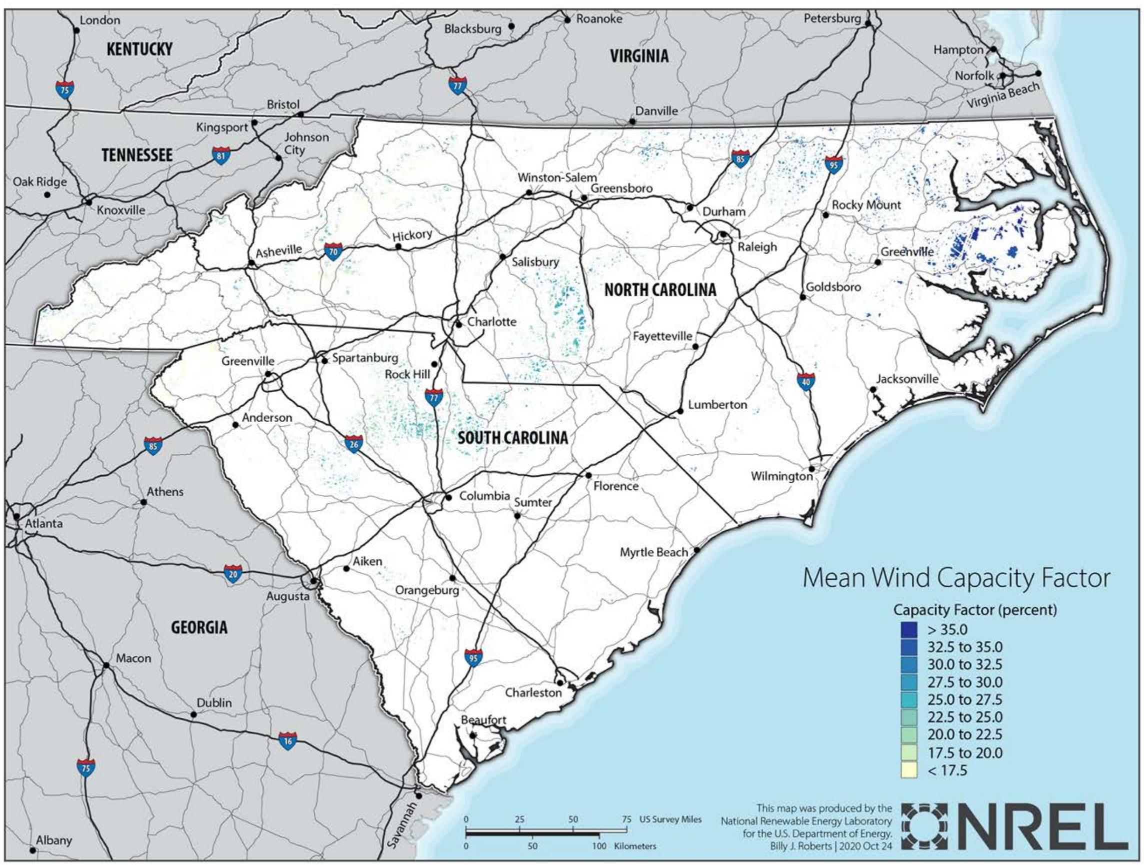

Figure A-2. Mean annual land-based wind capacity factors for potential sites in the Carolinas for the limited land-based wind sensitivity

The white areas indicate excluded sites. (See Figure 4 for a map of the baseline assumptions.)

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Appendix B: Additional Dispatch Results

This section provides plots of hourly generation by fuel type in Duke Energy's service territory for the entire year for both the nodal and zonal model scenarios. Figures B-1 through B-4 present the nodal model results, whereas Figures B-5 through B-7 present the zonal model results. Note that for these plots, some technologies have been aggregated (e.g., natural gas plants, offshore and land-based wind) for ease of viewing.

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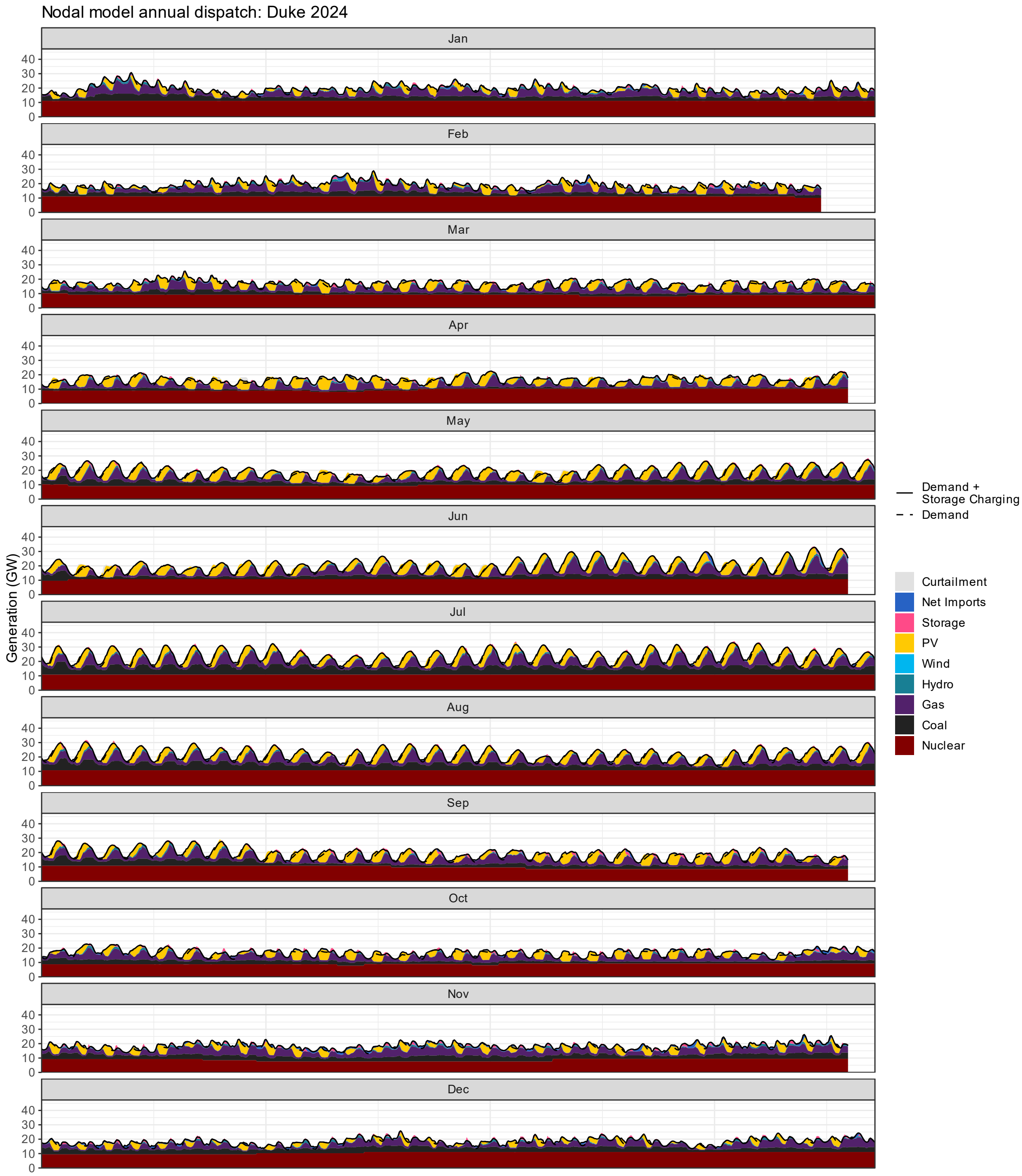

Figure B-1. Annual hourly generation by fuel type in the nodal model for the Duke 2024 scenario

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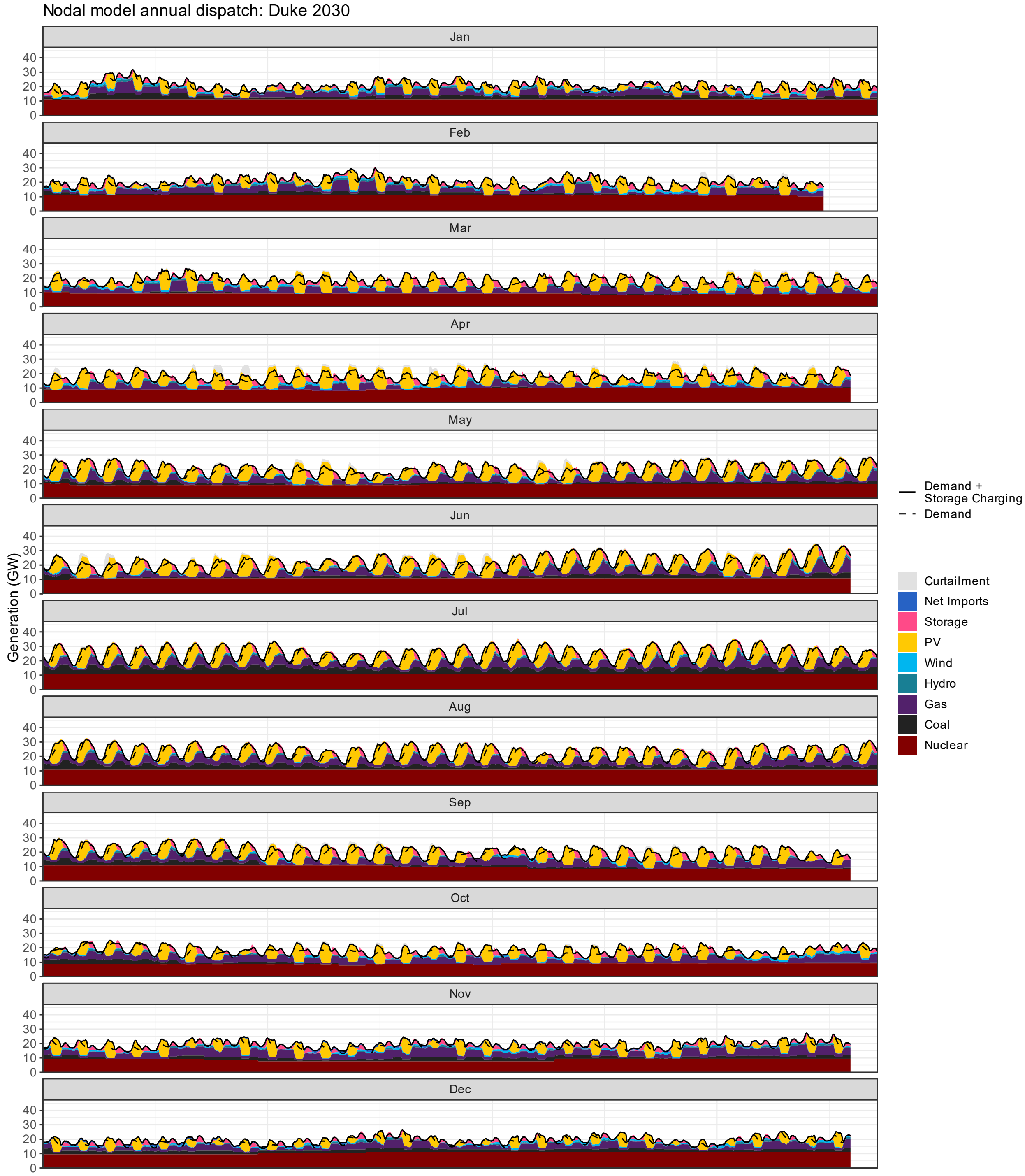

Figure B-2. Annual hourly generation by fuel type in the nodal model for the Duke 2030 scenario

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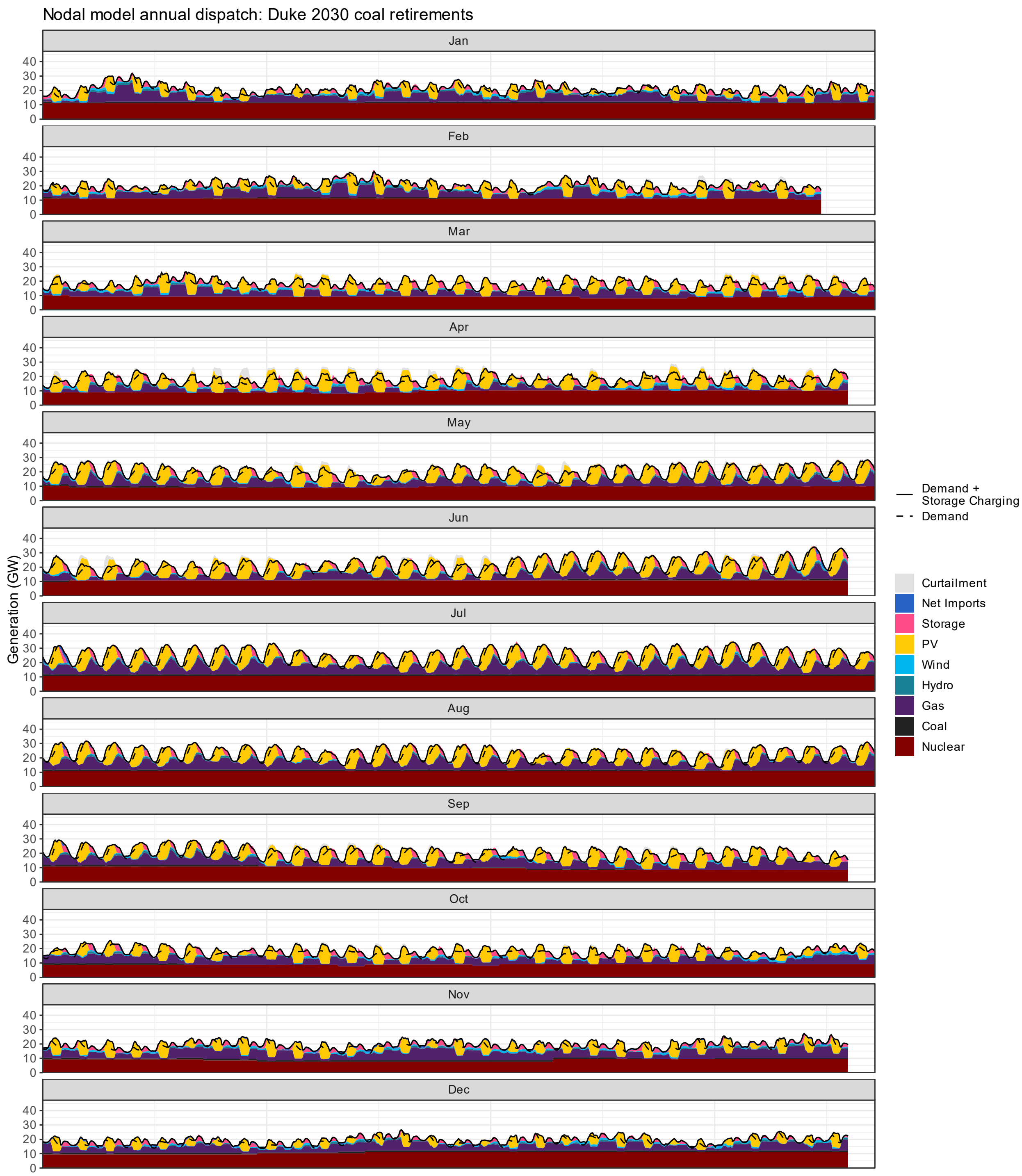

Figure B-3. Annual hourly generation by fuel type in the nodal model for the Duke 2030 coal retirements scenario

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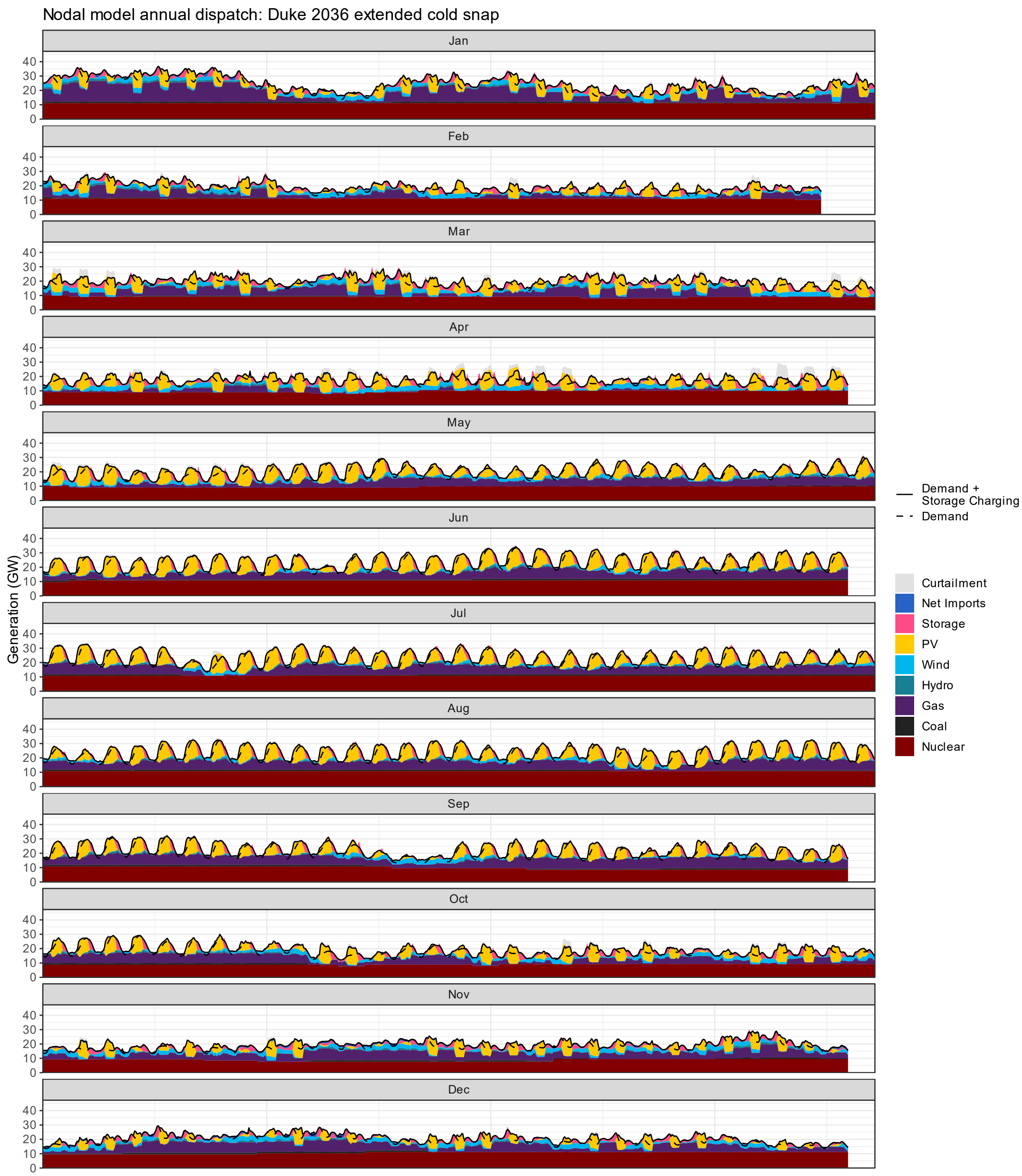

Figure B-4. Annual hourly generation by fuel type in the nodal model for the Duke 2036 extended cold snap scenario

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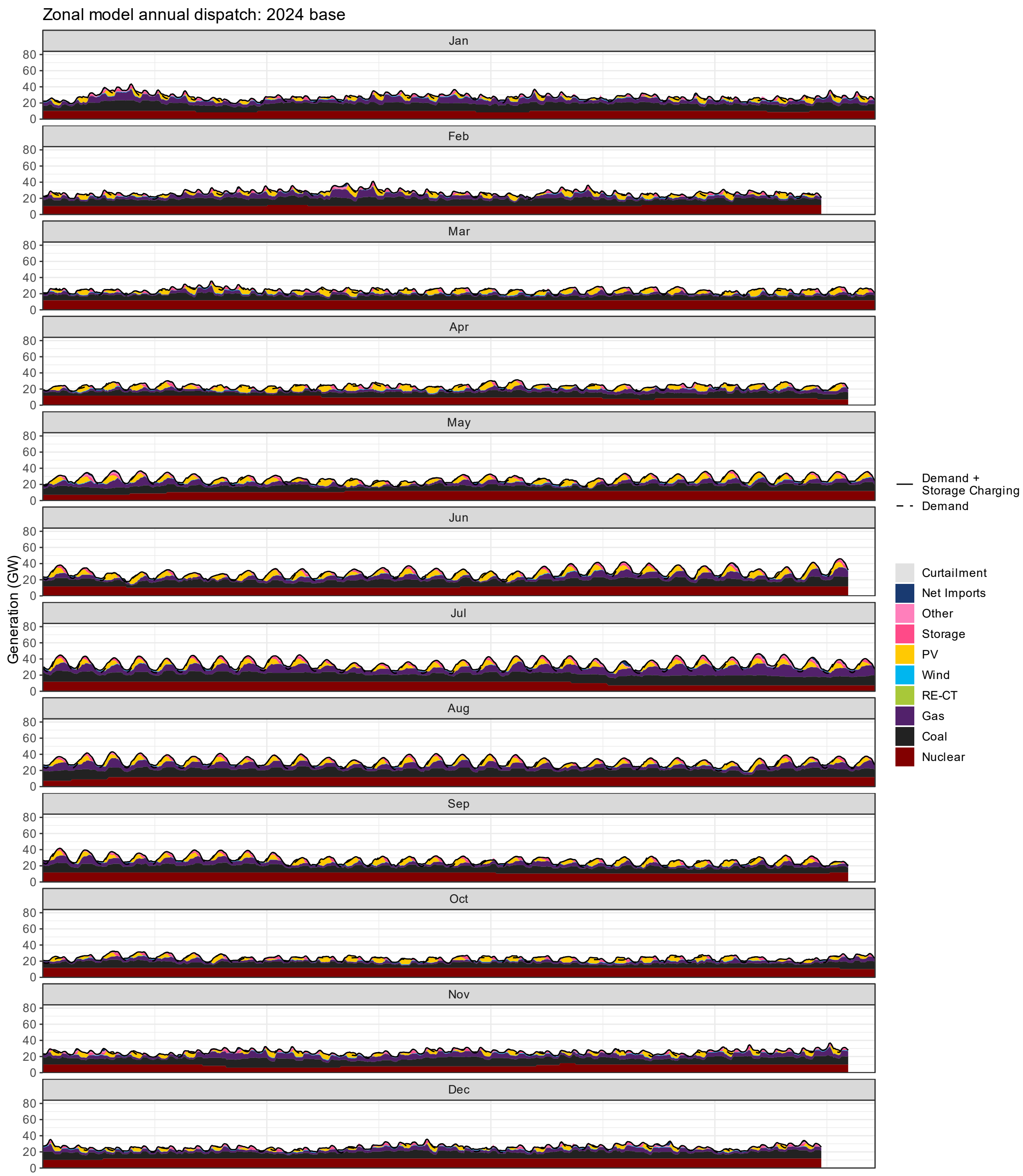

Figure B-5. Annual hourly generation by fuel type in the zonal model for the Carolinas 2024 base scenario

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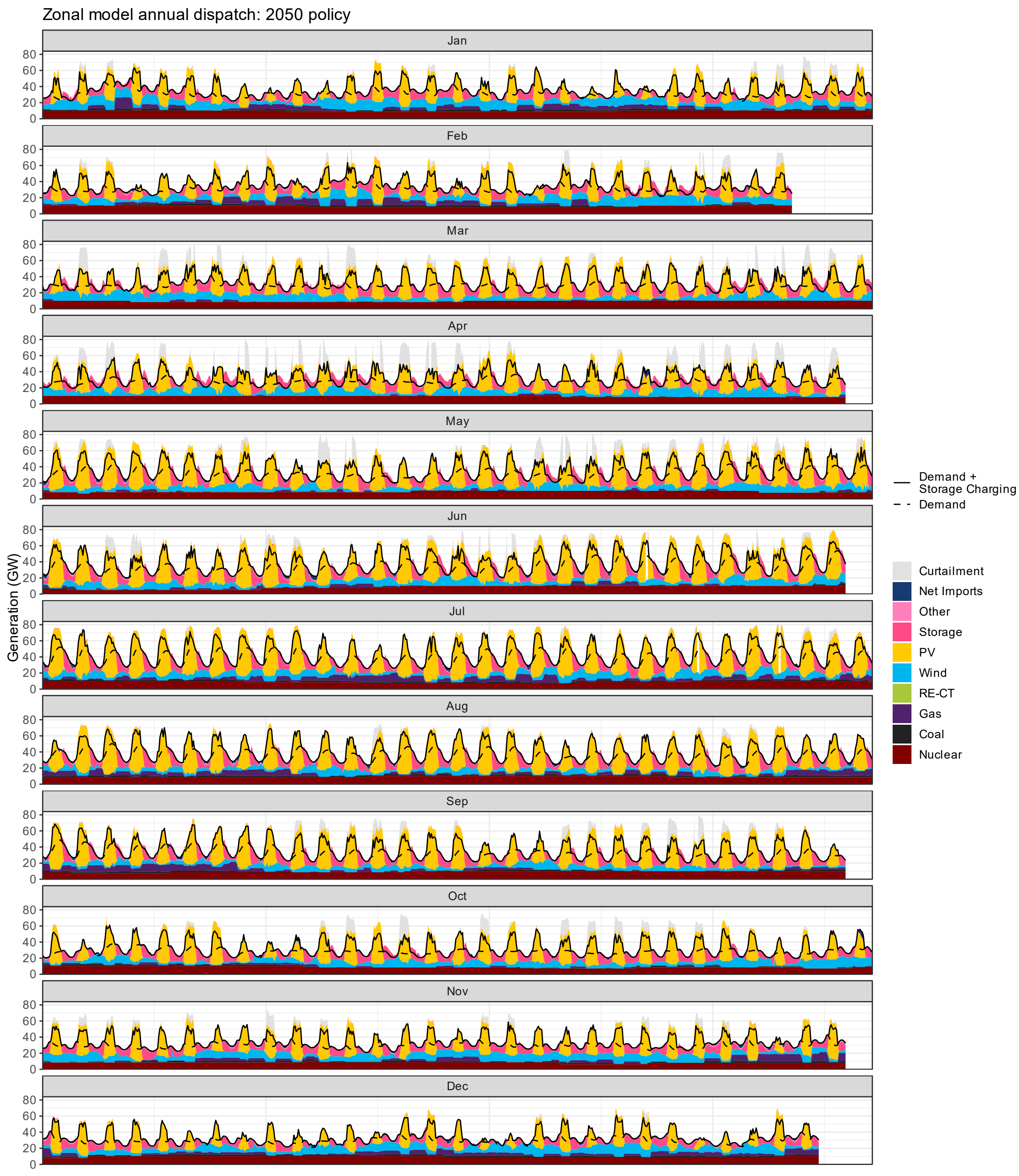

Figure B-6. Annual hourly generation by fuel type in the zonal model for the Carolinas 2050 policy scenario

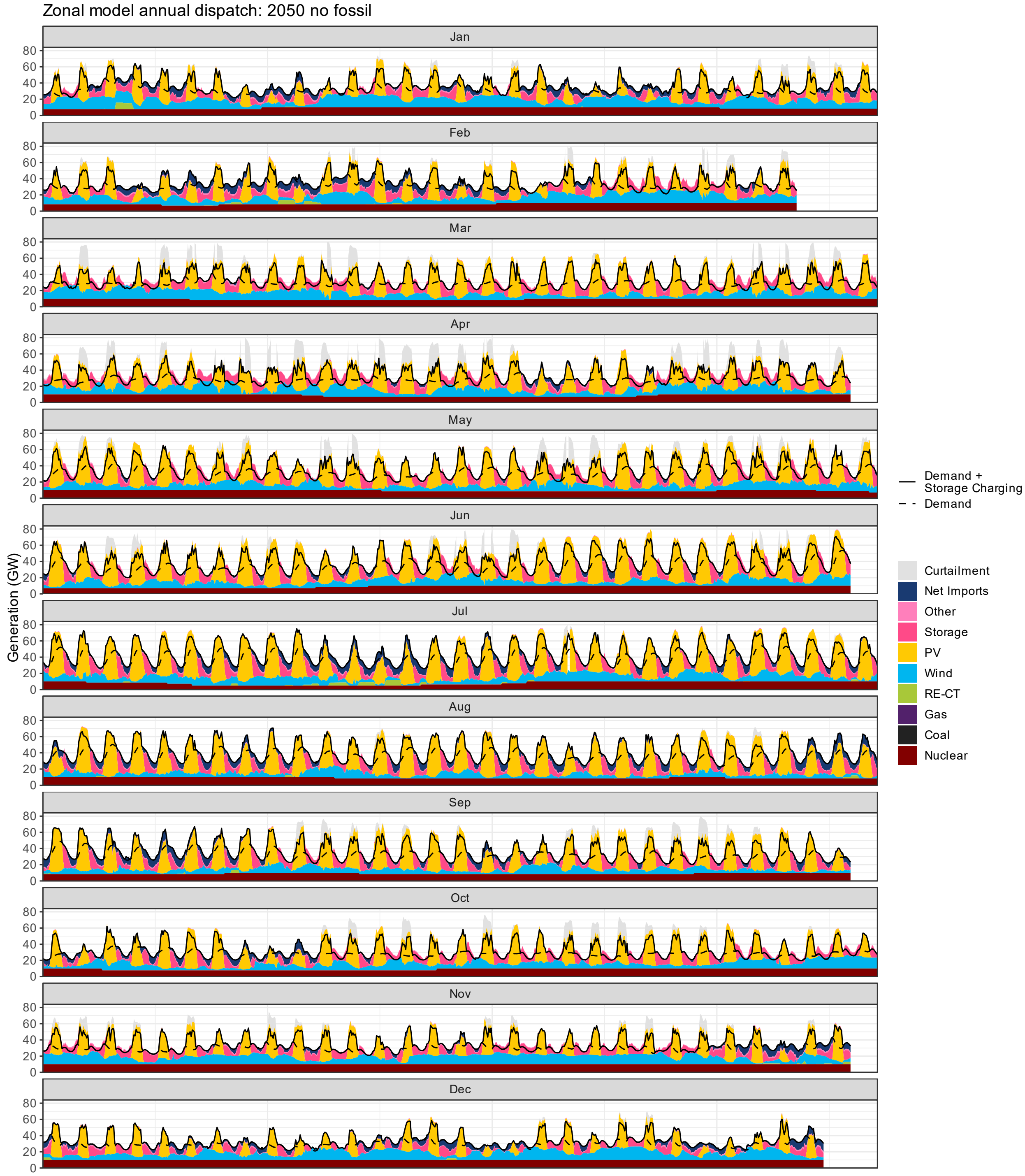

Figure B-7. Annual hourly generation by fuel type in the zonal model for the Carolinas 2050 policy no-fossil scenario

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Photo on front cover: Solar farm on the edge of Liberty, North Carolina. *From iStock 1363681015*

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