



An Electricity Resource Plan for Duke Energy Comprising Clean and Cost-Effective Generating Technologies

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Starla Yeh, Chandler LLC
Amlan Saha, PT Strategy & Intelligence LLC

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Executive Summary

This whitepaper evaluates Duke Energy’s 2023-2024 Carbon Plan and Integrated Resource Plan (CPIRP), Supplemental Filing, and July 2024 Amended Agreement and Stipulation of Settlement docket No. E-100, Sub 190 (the Stipulation)³ with a focus on identifying opportunities to augment clean and cost-effective resources. The analysis presents an alternative Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) resource mix for North Carolina, referred to throughout this discussion as the “EDF Scenario,” which includes more clean energy technologies (see adjacent box), and examines this alternative portfolio relative to other Near-Term Action Plans (NTAPs), including from the North Carolina Attorney General’s Office (“AGO”), the North Carolina Public Utilities Commission Public Staff (Public Staff), and Duke’s preferred proposal as set forth in the Stipulation (“Companies Stipulation”).

The EDF Scenario retires existing coal-fired capacity earlier, builds fewer natural gas-fired combined cycle units, and incorporates more wind and solar capacity relative to the other scenarios. The higher levels of both solar and wind resources under the EDF scenario acknowledge the rapidly declining costs of these clean technologies, improved feasibility of integration into the grid, and their vast potential to serve reserve margin requirements and other grid reliability services more economically when combined with energy storage systems. The EDF Scenario has the potential to make the DEC and DEP fleets cleaner, more cost-effective and more reliable, and benefit homes and businesses throughout the state through lower energy bills and less climate and air pollution.

Using an Excel-based analytical framework and focusing on Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) units in North and South Carolina, this analysis produces estimates of future emissions, overall electric generating capacity, and generation output under each of the four scenarios. The analysis did not analyze costs associated with the building or retiring of electric generating capacity. Furthermore, the analytical projections included herein are intended to be indicative in nature, reflecting the assumed compositions of the DEC and DEP fleets under the modeled scenarios.

EDF Scenario Recommendations:

Natural Gas: Only two new combined cycle (CC) units through 2038¹

Solar: 1,750 MW added per year beginning in 2028 until 2030, and 2,000 MW in 2031 and each year thereafter through 2038²

Wind (Onshore): 1,200 MW of land-based wind by 2032, with another 600 MW, or 125 MW per year, between 2033 and 2038, totaling 1,800 MW of land-based wind by 2038

Wind (Offshore): Revised timeline to ensure all offshore wind operational by 2035, with at least 800 MW of capacity added by 2031 and 850 MW each year from 2032 to 2035

Coal: Most coal units in North Carolina shut down by end of 2031, with the exception of Belews Creek units 1 and 2, which are retired in 2036

¹ One of these combined cycle units is anticipated to be located in South Carolina. It is included in the analytical framework for the purposes of having the ability to calculate emissions from DEC and DEP resources in both North and South Carolina. This assumption also applies in the Companies and AGO scenarios, and is consistent with the methodology contained in Duke’s CPIRP analyses.

² All or part of the new wind and solar capacities may be combined with energy storage systems to support any resource adequacy requirements (see Box on "Resource Adequacy Requirements" for a longer discussion)

³ The Stipulation is available at: <https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=59c2ab08-87a3-4fde-ac24-c88965673084>

Key Findings:

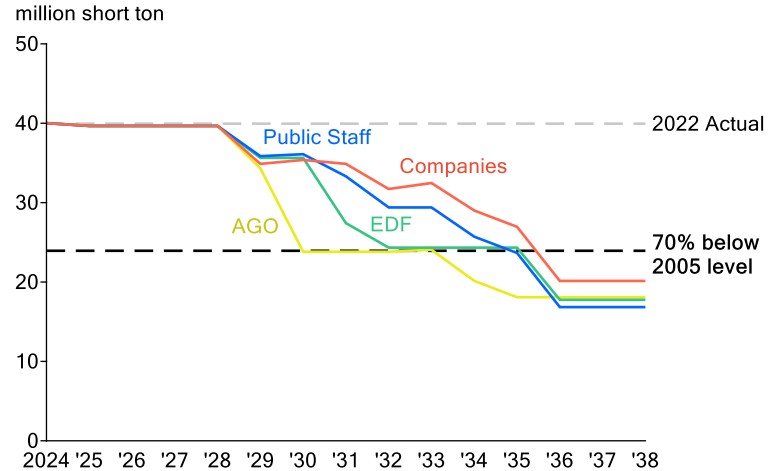
- The EDF Scenario reduces CO₂ emissions from the North Carolina DEP and DEC fleets by 7.5%, or 36.4 million tons, on a cumulative basis between 2024-2038, compared with the Companies Stipulation scenario and achieves 70% reduction in annual emissions by 2032 (relative to 2005)
- The steps suggested under the EDF Scenario would also deliver a lower risk path in terms of both CO₂ emission reduction and potential stranded assets for electricity consumers in North Carolina
- Retiring more coal facilities earlier than currently scheduled is the most impactful step Duke can take to reduce cumulative emissions and minimize stranded asset risk
- Hardcoded assumptions in Duke’s modeling approach result in artificially low solar new builds. Forced caps on how much solar capacity can be added each year as well as cost adders to solar and wind, as well as assumed capacity installation limitations that do not apply to natural gas-fired resources create biases that lead the model to select fewer solar new builds and more natural gas-fired resources
- A different set of, and potentially more realistic, assumptions and analytical methods would have introduced a broader array of clean resource technologies in an accelerated timeframe in Duke’s modeling

Figure ES-1. Resource Additions by Scenario

Comparison of Resource Additions by Scenario
MW

Technology	Year	Target Capacity (MW)			
		EDF	Companies Stipulation	Public Staff	AGO
Solar	2031	7,250	6,700	6,700	7,050
Battery Storage	2031	2,700	2,700	2,700	2,700
Onshore Wind	2032				2,250
	2033	1,200	1,200	1,800	
Combustion Turbines	2030			849	
	2032	575	2,125		
	2033				2,550
Combined Cycle	2030			1,359	2,720
	2032	2,720			
	2033		6,800		
Pumped Storage Hydro	2034	1,834	1,834	1,834	1,834
Advanced Nuclear	2035				
	2036	1,200	1,200	1,200	1,200
Offshore Wind	2032				1,600
	2034		2,400		
	2034-2035			2,200	
	2035	4,200			

Figure ES-2. Duke (DEC and DEP) CO₂ Emissions by Scenario and Year



I. Introduction and Scope

The purpose of this paper is to analyze Duke Energy's 2023-2024 Carbon Plan and Integrated Resource Plan (CPIRP), along with the July 2024 Stipulation and September 2023 supplemental filing. The primary objectives are to identify missed opportunities to incorporate and accelerate the addition of clean energy technologies that would lead to lower projected emissions, and to estimate the emissions reductions that could be driven by prioritizing clean energy technologies instead of fossil generation in the DEC and DEP fleets.

This whitepaper will provide an overview of the Duke CPIRP plan, with a focus on the preferred approach in the Fall 2023 supplemental filing with modifications as set forth in the July 2024 Stipulation, and will also survey the proposals set forth by the Public Staff and the North Carolina Attorney General's office (AGO). It will then describe the analytical framework developed for this whitepaper, and describe the analysis conducted on behalf of EDF showing that the DEC and DEP North Carolina fleets can meet the HB951 interim target of 70% below 2005 levels by 2032. The discussion will then briefly summarize the CO₂ emissions projections of the four plans, and show that the Companies Stipulation scenario could achieve lower CO₂ emissions outcomes with better planning and approaches to incorporating clean energy technologies. Finally, Section VII will point out key technical deficiencies in the Duke analysis that undermine its integrity and amount to pre-engineering the modeled outcomes. Further details on these topics are also available in the expert witness testimonies as referenced below.

This discussion focuses on the DEP and DEC units that are geographically located in North Carolina.⁴ The temporal focus of this discussion is the 2030-2035 time frame and cumulative emissions calculations over the period from 2024-2038.

II. Analytical Framework

The analysis described in this whitepaper was performed using an Excel-based analytical framework developed for EDF focusing on Duke Energy (including DEP and DEC) facilities located in North Carolina and South Carolina. It relies on public data from the Environmental Protection Agency (EPA) and detailed power sector information that the United States Energy Information Administration (EIA) makes available through its various survey form datasets and monthly and annual energy reports. This framework generates estimates of future emissions, electric generating capacity, and output based on user selections and historical data. It does not account for economic cost factors of building or retiring electric generating capacity, but rather performs calculations based on how a user specifies the composition of the fleet and uses heuristics and simplifying assumptions to produce projections at an indicative level.

For the purposes of this analysis, the EDF Scenario was developed and analyzed relative to the Companies Stipulation and Public Staff NTAP. For calibration of the analytical framework, the Companies Stipulation, the Public Staff NTAP, and the AGO's recommendation were replicated using this analytical framework. For consistency, most comparisons provided throughout this whitepaper involving the Companies Stipulation and Public Staff NTAP are based on calculations generated by the analytical framework described here. Any references to Companies Stipulation or Public Staff NTAP emissions projections are specifically noted in the text.

⁴ DEP and DEC units comprise electric generating units (EGUs) in North Carolina that are listed under the entities Duke Energy Progress, Duke Energy Carolinas, and Duke Energy Renewable Services in that state as reflected in EIA Survey Form 860 data for 2022.

III. Overview of Proposals: The Companies Stipulation, Public Staff, and AGO

In the 2023 Carolinas Resource Plan proceedings, three principal outlooks for DEC and DEP electric generating units have emerged.

The Companies (Duke Energy). The Duke Energy Carolinas Resource Plan was filed with the North Carolina Utilities Commission as the 2023-2024 Carbon Plan and Integrated Resource Plan (CPIRP) on August 17, 2023, in Docket No. E-100, Sub 190. In the CPIRP, Duke set forth three core pathways for the DEC and DEP fleets and focused on the third scenario (referred to as “P3”) as its preferred path. Duke submitted supplemental and additional portfolio analysis in support of its 2023 Carolinas Resource Plan to account for developments that were not captured in the original modeling analysis.

Duke’s P3 Fall Base forecasts more gas generation than in P3 in 2038. Wind and solar account for a greater share of the 2038 generation mix in P3 Fall Base than in P3, while nuclear generation is reduced compared with P3. These differences are driven primarily by a significant increase in the load forecast analyzed in the supplemental filing.⁵ The supplemental filing also provides a near-term action plan (NTAP) focused on the time period up to 2035 that incorporates the results of P3 Fall Base from the additional planning analysis. In July 2024, the Companies, Public Staff, Walmart, Inc. and Carolinas Clean Energy Business Association (CCEBA) submitted the July 2024 Amended Agreement and Stipulation of Settlement Docket No. E-100, Sub 190, an agreement which includes modifications to the Companies NTAP resulting from engagement among the parties.

This scenario is referred to throughout this analysis as the Companies Stipulation. Duke projects that CO₂ emissions from the DEC and DEP units in the Companies NTAP and P3 Fall Base to be 30 million short tons in 2035 across both NC and SC, and 25 million short tons in NC alone.⁶ Constructing the Companies Stipulation in the Excel-based analytical framework used in this analysis, estimates for 2035 emissions of the portfolio across both Carolinas (29.2 million short tons) and NC (27.0 million short tons) are broadly consistent with Duke’s projections. Using the same framework, this analysis estimates 2032 emissions of the same portfolio to be 37.6 million short tons in both NC and SC, and 35.4 million short tons in NC alone.

Public Staff. In the 2023 CPIRP proceeding before the NCUC, the Public Staff represents the interests of consumers and ratepayers. The Public Staff’s objectives are to ensure that the state carbon reduction goals are met in a reliable and least cost manner, while minimizing any rate impacts on Duke ratepayers. Public Staff has provided a proposed near-term action plan (NTAP) for the NCUC’s consideration as an alternative to P3 Fall Base. Compared with the Companies Stipulation, Public Staff’s NTAP includes a greater amount of wind and solar capacity in 2031-2033. Public Staff also reduces the combustion turbine (CT) capacity in the Companies Stipulation by half and includes just one-fifth of the Companies Stipulation’s planned combined cycle (CC) capacity. This analysis estimates the 2032 emissions of the

⁵ The Companies Stipulation and EDF scenarios constructed in this analysis are presumed to align broadly with the P3 Fall Base energy demand levels. Because the emission profile of the Companies Stipulation portfolio reconstructed in this analysis approximately matches P3 Fall Base and the original Companies Stipulation, the amount of fossil generation must be similar. Further, since the non-emitting portion of the portfolio also largely replicates the schedule of new build additions under the two scenarios, the reconstructed scenarios are implied to be able to serve similar energy load levels. The reconstructed Companies Stipulation scenario forms the basis for the EDF Scenario, and any incremental fossil retirements are assumed to be offset with additions of new clean resources.

⁶ Emissions estimates of the DEC and DEP fleets are given in the Supplemental Filing and analysis, however are excluded from the Stipulation. The emissions estimate specified here is taken from the Supplemental filing and analysis, while the scenario constructed in the analytical framework reflects the Stipulation until 2032, and adopts the resources in P3 Fall Base from the Supplemental filing and analysis for the years 2033-2038. The Stipulation is closely aligned with P3 Fall Base, though with some modest differences in the period preceding 2033, making the emissions differences potentially minimal.

Public Staff NTAP portfolio as 31.6 million short tons for both NC and SC⁷, and about 29.4 million short tons in NC alone. In 2035, this analysis estimates emissions of the DEP and DEC fleets in both NC and SC to be 25.9 million short tons, and 23.7 million short tons in NC.^{8,9}

Attorney General's Office. A third critical perspective in these proceedings is offered in testimony by Edward Burgess of the AGO.

The AGO recommends that the Commission: (1) direct Duke to achieve the interim target no later than 2032, balancing the temporal requirement of the target with the demand increases described in the supplemental filing; (2) direct Duke to pursue strategies for accelerated coal retirement and increasing renewables deployment¹⁰; (3) weigh challenges in securing firm transportation capacity for natural gas; (4) conduct independent load forecast analysis to validate Duke's projections in future CPIRP processes; (5) direct Duke to supplement its resource planning with additional customer-focused demand-side options; and (6) require Duke to explore transmission-related solutions. The AGO's proposed alternative pathway to meet the HB951 target in 2032 is represented in the table below.¹¹

⁷ The Public Staff scenario was constructed in the analytical framework relying on the NTAP given in Expert Witness Metz's testimony through 2032. Capacity installations in the years 2033-2038 were taken from the Supplemental filing and P3 Fall Base for 2035 and 2038 and interpolated for the intervening years.

⁸ Expert witness testimony of Dustin R. Metz on behalf of Public Staff provides cumulative emissions projections from scenarios it modeled in Encompass. These cumulative projections range from 585-693 million short tons in 2038, broadly consistent with the cumulative emissions estimates derived from this analysis. Direct Testimony of Dustin R. Metz, Expert Witness for Public Staff, Docket E-100, SUB 190 at page 143.

⁹ Expert witness testimony of Dustin R. Metz on behalf of Public Staff includes scenarios showing wide-ranging projections for the role of gas-fired electricity generating units. Expert Witness Metz also includes cautious language pertaining to gas capacity additions. For example, "Public Staff does not support Duke's proposal [...]for five combined cycles by 2026 due to concerns about fuel supply, EPA 111(b) regulations, large economic load materialization, and the risk of stranding these assets [...]" Direct Testimony of Dustin R. Metz, Expert Witness for Public Staff, Docket E-100, SUB 190 at page 163.

¹⁰ AGO does not develop a specific retirement schedule in the testimony of expert witness Edward Burgess. Instead, it references the retirement schedule implicit in Duke's P1, which meets the Interim Target in 2030. The language in expert witness Edward Burgess's testimony describing coal retirements emphasizes, "accelerating coal retirements towards 2030," and notes specifically that "[E]arlier retirements for Belews Creek and Roxboro may be a critical path for achieving an Interim Target in line with the statutory guidance". Direct Testimony of Edward Burgess, Expert Witness for the Attorney General's Office, Docket E-100, SUB 190 at 27-28.

¹¹ It is notable that the AGO's assumed capacity factor for solar is 35%. The EDF Scenario assumes that capacity factors for new solar facilities are 21%, based on actual achieved capacity factors in North Carolina. Augmenting the solar capacity factor assumption in the EDF Scenario to align with the AGO's assumption would help the EDF fleet support higher loads. This could be an important factor since Duke identifies significant load increases in its Supplemental Planning Analysis.

Table 1. AGO’s Illustrative Compliance Pathway for the Interim Target (reproduced from Edward Burgess’s expert testimony)

AGO Conceptual Illustration of an Interim Compliance Pathway						
MW by Year	Solar ³⁰	Onshore Wind (Carolinas) ³¹	Onshore Wind (Imported) ³²	Offshore Wind ³³	Incremental DSM/EE	Total Clean
2027	0	0	0	0	0	
2028	1,350	0	0	0	100	
2029	1,800	300	150	0	100	
2030	1,800	450	150	0	100	
2031	2,100	450	150	0	100	
2032	2,100	450	150	1,600	100	
Sum by 2032 (MW)	9,150	1,650	600	1,600	500	
Capacity Factor	35%	27%	30%	41%	50%	
GWh	28,461	3,903	3,679	5,606	2,190	41,470

Note: Wind capacity additions in the AGO’s plan includes imported capacity. For the purposes of this analysis, it is assumed to be in-state. This assumption does not affect emissions estimates.

According to the analytical framework developed for this analysis, 2032 CO₂ emissions of the DEC and DEP fleet in NC and SC total 26.0 million short tons, of which 23.8 million short tons are from NC facilities. In 2035, this analysis estimates that emissions would decrease to 20.3 million short tons in both NC and SC, and 18.1 million short tons in NC alone.¹²

The EDF Scenario. The EDF Scenario was prepared specifically for this analysis and is broadly aligned with the Public Staff’s NTAP. The EDF Scenario adopts many of the AGO’s views on modifying Duke’s coal retirement schedule and accelerating the addition of zero-emitting technologies. The principal premise of the EDF scenario is to select a schedule of generating resource additions and retirements that would reduce cumulative CO₂ emissions below Duke’s and Public Staff’s projections, though not as far as AGO’s office’s proposal. The EDF scenario would also meet the 70% reduction target by 2032, with guidance from the materials and data from CPIRP filings on the cost-effectiveness of various resource types.

EDF Scenario Revenue Considerations

The analytical framework used in this analysis did not estimate present value revenue requirements (PVRR) of the EDF Scenario. However, composition of the DEP and DEC fleets and general schedules of resource addition assumed under the EDF Scenario are broadly within the bookends of sensitivity runs included in the testimony of expert witness Dustin R. Metz on behalf of Public Staff (see footnote 7-9).

As such, for illustrative purposes, an indicative PVRR for the EDF Scenario could be expected to lie within the relatively narrow range of PVRRs provided in that testimony.

The EDF Scenario eliminates three new combined cycle (CC) units, and retires most coal units in NC by the end of 2031, with the exception of Belews Creek units 1 and 2. Belews Creek units 1 and 2 are the largest coal units across the DEC and DEP fleets. Consistent with P3 Fall Base and the Companies

¹² The AGO scenario was constructed in the analytical framework relying on the illustrative compliance pathway through 2032. Capacity installations in the years 2033-2038 were taken from the Supplemental filing and P3 Fall Base for 2035 and 2038 and interpolated for the intervening years.

Stipulation, Belevs Creek units 1 and 2 are assumed to retire in 2036. This analysis does not modify the retirement schedule for Belevs Creek units 1 and 2 on the basis that these are likely to be the most efficient and cost-effective coal generating units in the fleet. The two units also have fuel switching capabilities and already co-fire with a significant share of natural gas. The EDF Scenario also includes no new combustion turbine units. The EDF Scenario includes 2,500 MW of offshore wind by 2033, and about 4,200 MW by 2035. Further, this scenario also assumes 600 MW of new incremental land-based wind capacity coming online each year between 2031-2033 and a further 600 MW beginning operation by 2038, adding up to 1,800 MW of total new land-based wind capacity by 2038. The EDF Scenario also envisions 1,200 MW of advanced nuclear capacity by 2038, which is consistent with Public Staff's NTAP and the Companies Stipulation.

Resource Adequacy Requirement

Fossil-fired generating capacities under three out of the four scenarios considered in this analysis—EDF, Public Staff, and AGO—are significantly lower than under the Companies scenario. This is due to avoided new natural gas CC units, accelerated coal retirements, or both.

While this analysis did not undertake specific resource adequacy analyses of the four scenarios, to the extent the excluded fossil-fired resources in the Companies scenario are required to meet any anticipated resource adequacy (RA) requirements, two major factors suggest that replacement zero-emitting resources assumed under the three scenarios would be able to provide similar grid supporting ancillary services and meet reserve margin requirements.

First, battery energy storage systems (BESS) are increasingly assuming roles in providing system-wide ancillary and RA services.^a For example, in ERCOT and CAISO, BESS can provide all major ancillary services including regulation up/down, spinning/non-spinning reserve. CAISO notes that BESS “[...] have consistently offered many times more [...]” ancillary services than the market requires. Furthermore, on average across its system, more than 94% of BESS nameplate capacity was available for resource adequacy purposes.^b Playing similar roles in ERCOT, BESS is estimated to have saved \$750 million in system costs in 2023. Thus, combining wind and solar with BESS could provide all needed grid ancillary services and boost significantly the share of their name plate capacities available for resource adequacy purposes.

Second, as outlined elsewhere in this whitepaper, the Companies scenario is based on peak load growth forecasts that may not materialize due a combination of technological changes, energy efficiency gains, demand shifting, and potentially canceled projects. These uncertainties are especially relevant since the primary drivers of additional load growth in the Companies scenario—data centers, electric vehicle manufacturing, semiconductors—are all currently in the midst of major technological, efficiency, and market upheavals that have the potential to significantly impact their load profiles going forward. By not factoring them adequately in the assumptions, the Companies scenario may be overestimating the level of resources needed to meet reserve margin requirements. Additionally, as Fitch and Moody's, two major credit rating agencies, recently noted, overbuilding of resources driven by highly optimistic load growth forecasts has the potential to undermine credit ratings of utilities and saddle ratepayers with disproportionate costs.^c

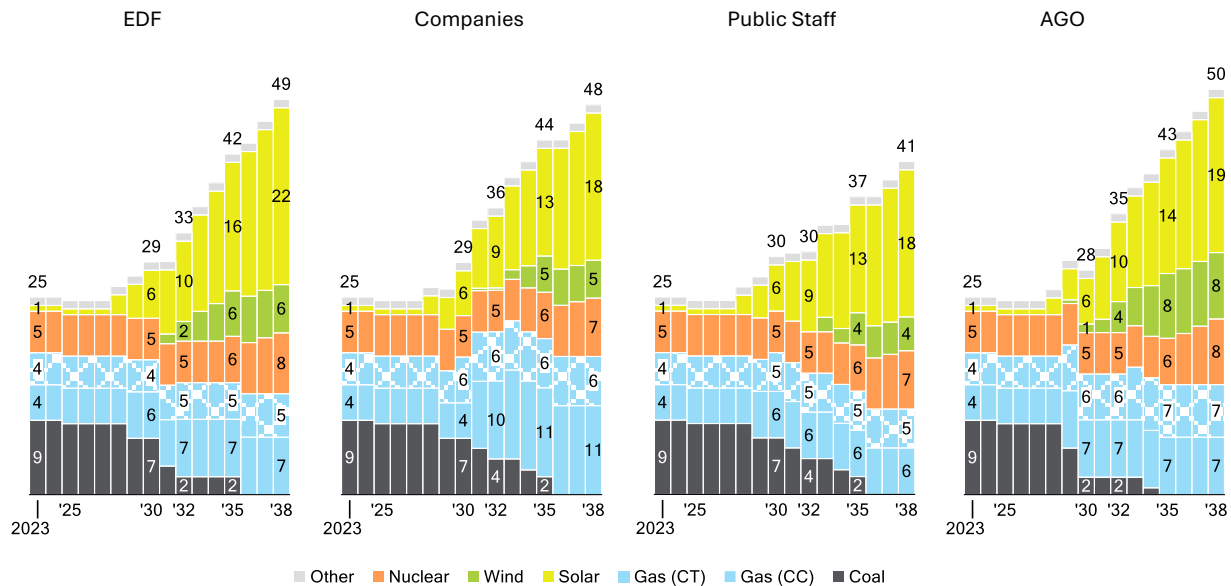
^aSee Aurora Energy Research, *Role of Battery Energy Storage Systems (BESS) in the ERCOT market* (May, 2024), https://go.auroraer.com/1/885013/2024-05-21/n4rl6/885013/1716308186gOCcibDh/Eolian_Role_of_Batteries_in_ERCOT_Final_Public_v2_1_.pdf

^bSee California ISO, *2023 Special Report on Battery Storage* (July, 2024), <https://www.caiso.com/documents/2023-special-report-on-battery-storage-jul-16-2024.pdf>

^cSee Allison Good, *Credit risks loom for utilities that overestimate datacenter demand* (July 26, 2024), <https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/credit-risks-loom-for-utilities-that-overestimate-datacenter-demand-82567534>

Finally, this analysis finds that the new combustion turbine capacity in Public Staff’s NTAP is not likely to have a material impact on emissions if utilized at a low rate of 5% or less. However, its impacts could be more significant on electricity rates and leave ratepayers with greater exposure to stranded asset risk. While this analysis did not consider the potential impacts of proposed federal regulations on the emissions of carbon dioxide from existing coal and new gas units, notwithstanding, rapidly increasing shares of renewable resources in electricity grids across the U.S. are likely to progressively reduce the number of hours during which natural gas-fired power generating resources are able to operate. For example, rising renewable and clean portfolio standards combined with tax credit provisions of the Inflation Reduction Act (IRA) could drive the share of renewable generation in the U.S. from about 23% in 2022 to 63% in 2050; during the same period, natural gas-fired generation’s share declines from just under 40% to about 22%.¹³ As a result of these constraining factors and given their useful lives of 25 years or more,¹⁴ new natural gas-fired generating resources face significant potential stranded asset risk going forward.

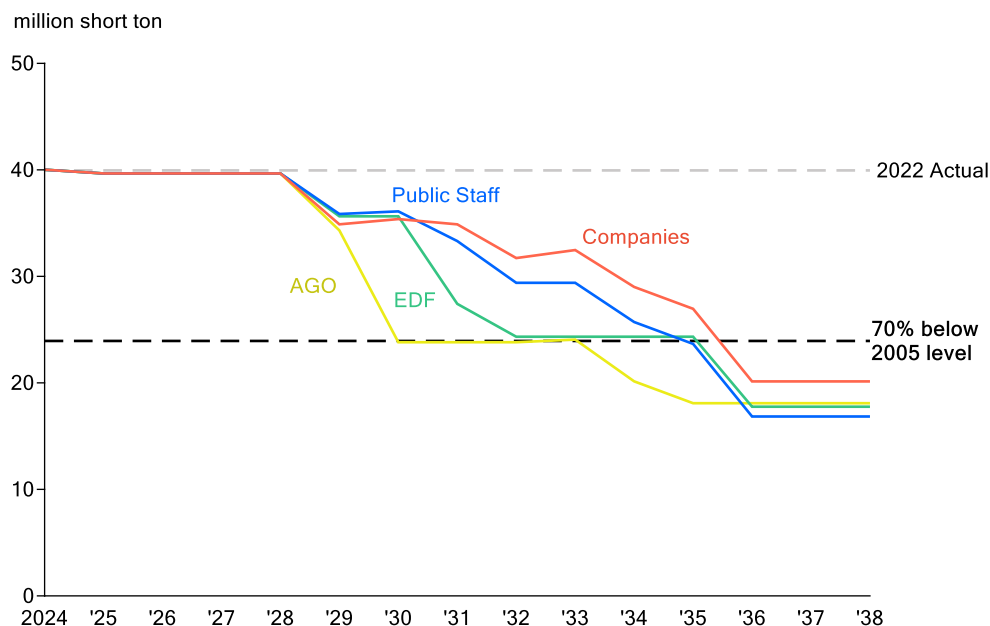
Figure 1. Duke (DEP and DEC) North Carolina Portfolio by Scenario, Resource Type, and Year (GW)



¹³ See EIA AEO 2023, <https://www.eia.gov/outlooks/aeo/>, and Galen Barbose, Berkley Lab, U.S. State Renewables Portfolio & Clean Electricity Standards: 2023 Status Update, https://eta-publications.lbl.gov/sites/default/files/lbnl_rps_ces_status_report_2023_edition.pdf

¹⁴ See EIA / Sargent and Lundy, Capital Cost Study Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies, https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

Figure 2. Duke (DEP and DEC) North Carolina CO₂ Emissions by Scenario and Year (million short ton)



IV. Emissions Performance Analysis

The EDF Scenario achieves a reduction in carbon dioxide emissions from the North Carolina portfolio of DEC and DEP of 70% by 2032. Under the EDF Scenario, this analysis estimates 2032 emissions from the DEC and DEP facilities to be 26.5 million short tons in both NC and SC, and 24.3 million short tons in NC alone. In 2035, CO₂ emissions of the EDF Scenario resource mix total 26.5 million short tons in NC and SC, and 24.3 million short tons in NC.

Several viable potential options for reducing emissions further than projected in Duke’s analyses are illustrated in Public Staff NTAP, the AGO’s recommendation and the EDF Scenario prepared for this analysis.

The EDF Scenario constructed in this analysis demonstrates that the key modifications that would benefit the emissions performance of the DEC and DEP fleet are the following, which are well-aligned with Public Staff’s NTAP and the AGO’s recommendations:

- (1) Eliminate three planned new combined cycle (CC) units
- (2) Add 1,750 MW per year of new solar capacity beginning in 2028 until 2030, and 2,000 MW in 2031 and each year thereafter through 2038 to replace the generation gap that may arise as a result of eliminating the new CC builds; all or part of the new solar capacity may be combined with energy storage systems to support resource adequacy requirements, as is also envisioned under the Companies Stipulation¹⁵ (see Box on “Resource Adequacy Requirements” for a longer discussion)
- (3) Add 1,200 MW of land-based wind by 2032, with another 600 MW, or 125 MW per year, between 2033 and 2038, totaling 1,800 MW of land-based wind by 2038.

¹⁵ Amended Agreement and Stipulation of Settlement Docket No. #-100, Sub 190, available at: <https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=59c2ab08-87a3-4fde-ac24-c88965673084> (see pages 6-7)

- (4) Advance the timeline for building and connecting offshore wind resources in order to displace potential demand for the new CC units, and ensure that all offshore wind is built and operational by 2035 with at least 800 MW of capacity added in 2031, and 850 MW each year from 2032 to 2035.
- (5) Retire most coal units in North Carolina by the end of 2031, with the exception of Belews Creek units 1 and 2, which retire in 2036

The resulting EDF portfolio is projected to emit 35.6 million short tons in 2030, a 56% reduction below 2005, and 24.3 million short tons in 2032, achieving the HB951 interim target of 70% below 2005. Cumulatively between 2024 and 2038, this portfolio is estimated to total 448 million short tons, or 3.2% lower than the Public Staff NTAP and 7.5% lower than the Companies Stipulation.

V. Resource Additions and Coal Retirements in the EDF Scenario

The various proposals put forth in the CPIRP process are given in the table below, and the remainder of this section provides more detail pertaining to the schedule of resource additions and coal retirements under the EDF Scenario.

Coal unit retirement schedule. The EDF Scenario assumes an advanced coal retirement schedule such that most coal units are retired by the end of 2031. These modifications to Duke’s preferred schedule in the Companies Stipulation are both feasible and beneficial from a CO₂ emissions perspective. Retiring more coal facilities earlier is the most impactful step Duke can take to reduce cumulative emissions and minimize stranded asset risk.

Table 2. DEC and DEP Fleet CO₂ Emissions Comparison of EDF Scenario with Key Stakeholder NTAPs

DEC and DEP North Carolina Fleet CO₂ Emission Reduction (by Scenario)								
<i>million short ton</i>								
Annual Emission by Year					% Reduction Rel. to 2005			
Year	EDF	Public Staff NTAP	Companies Stipulation	AGO	EDF	Public Staff NTAP	Companies Stipulation	AGO
2022	39.9	39.9	39.9	39.9	-50%	-50%	-50%	-50%
2025	39.7	39.7	39.7	39.7	-50%	-50%	-50%	-50%
2030	35.6	36.1	35.4	23.8	-55%	-55%	-56%	-70%
2032	24.3	29.4	31.7	23.8	-70%	-63%	-60%	-70%
2033	24.3	29.4	32.5	24.1	-70%	-63%	-59%	-70%
2035	24.3	23.7	27.0	18.1	-70%	-70%	-66%	-77%
2038	17.8	16.8	20.1	18.1	-78%	-79%	-75%	-77%
Cumulative Emission								
2024-38	448.0	462.6	484.4	421.0				

Duke Carolinas								
<i>million short ton</i>								
Annual Emission by Year					% Reduction Rel. to 2005			
Year	EDF	Public Staff NTAP	Companies Stipulation	AGO	EDF	Public Staff NTAP	Companies Stipulation	AGO
2022	42.2	42.2	42.2	42.2	-49%	-49%	-49%	-49%
2025	41.9	41.9	41.9	41.9	-49%	-49%	-49%	-49%
2030	37.8	38.3	37.6	26.0	-54%	-54%	-55%	-69%
2032	26.5	31.6	33.9	26.0	-68%	-62%	-59%	-69%
2033	26.5	31.6	34.7	26.3	-68%	-62%	-58%	-68%
2035	26.5	25.9	29.2	20.3	-68%	-69%	-65%	-75%
2038	20.0	19.1	22.3	20.3	-76%	-77%	-73%	-75%
Cumulative Emission								
2024-38	481.1	495.8	517.5	454.2				

Table 3. Resource Additions by Scenario

Comparison of Resource Additions by Scenario

Technology	Year	Target Capacity (MW)			
		EDF	Companies Stipulation	Public Staff NTAP	AGO
Solar	2031	7,250	6,700	6,700	7,050
Battery Storage	2031	2,700	2,700	2,700	2,700
Onshore Wind	2032				2,250
	2033	1,200	1,200	1,800	
Combustion Turbines	2030			849	
	2032	575	2,125		
	2033				2,550
Combined Cycle	2030			1,359	2,720
	2032	2,720			
	2033		6,800		
Pumped Storage Hydro	2034	1,834	1,834	1,834	1,834
Advanced Nuclear	2035				
	2036	1,200	1,200	1,200	1,200
Offshore Wind	2032				1,600
	2034		2,400		
	2034-2035			2,200	
	2035	4,200			

Table 4. Comparison of Coal Unit Retirement Schedules

Comparison of Coal Capacity Retirement Schedules (by Scenario)

<i>MW</i>				
Retirements by year				
Year	EDF	Public Staff NTAP	Companies Stipulation	AGO
2022				
2023				
2024				
2025	421	421	421	421
2026				
2027				
2028				
2029	1,817	1,787	1,817	3,035
2030				3,612
Total by 2030	2,238	2,208	2,238	7,068
2031	3,454	1,248	1,248	
2032	1,318	1,318	1,318	
Total by 2032	7,010	4,774	4,804	7,068
2033				
2034		1,392	1,362	1,318
2035		844 ¹⁶	844 ¹⁶	844 ¹⁶
Total by 2035	7,010	7,010	7,010	9,230
2036	2,220	2,220	2,220	
2037				
2038				

In the EDF Scenario, Roxboro Units 2 and 3 retire in 2031 instead of 2034,¹⁷ as in the Companies Stipulation. Additionally, James E. Rogers Energy Complex Unit 6 (formerly Cliffside Unit 6) is scheduled to retire in 2031 rather than in 2035. The two Belews Creek units remain online until 2036. The

¹⁶ James E. Rogers Energy Complex Unit 6 is planned for gas conversion in Duke’s analysis. To reflect gas conversion in this framework, the 844 MW unit is assumed to retire in 2035, and the capacity is then added as combustion turbine (CT) capacity beginning operation in 2036.

¹⁷ The retirement of Roxboro Units 2 and 3 in the EDF Scenario coincides with the scheduled in-service dates of Duke’s new combined cycle units.

EDF Scenario does not modify the retirement schedule for the Belews Creek units from P3 Fall Base, as these units are the largest and among the most efficient steam units in the DEC and DEP fleets; they also co-fire a significant volume of natural gas.

Implementation of this retirement schedule—a virtual necessity to reduce cumulative emissions from the fleet and moderate asset risk—would require careful advance planning and in-depth evaluation of a full range of system level augmentations including transmission upgrades, installation of special equipment that in some cases can have long lead times, integration of energy storage with renewable resources, and investment in more renewable resources. Absence of a comprehensive evaluation of options in Duke’s CPIRP analyses and recent multi-year rate plan proposals suggests that its coal retirement schedule would not be aligned with North Carolina’s interim targets. As noted earlier in this white paper, direct testimony of Edward Burgess, expert witness for AGO, discusses this point in detail and reaches a similar conclusion.¹⁸

Solar Capacity Additions. The EDF Scenario includes more new solar capacity and accelerated deployment of both onshore and offshore wind in comparison with the Companies Stipulation. Under the EDF Scenario, 1,750 MW of new solar is added each year between 2028 and 2031, increasing to 2,000 MW per year in 2032. As a result, under the EDF Scenario, 7,250 MW of total new solar capacity is added by 2031 compared with 6,700 MW under the Companies Stipulation and Public Staff’s NTAP scenarios.

Solar energy is expected to be the most cost-effective of the new generating resource types.¹⁹ As technology costs continue to decline and solar technology continues to evolve, the feasibility of building and integrating solar energy is rapidly increasing.²⁰ As a consequence of enhanced efficiency, the integration of smart technologies, and advancements in materials and design, solar power is becoming an increasingly versatile energy source. Moreover, investing more in solar as part of the Carbon Plan would ensure a safe and affordable future for North Carolina communities by, reducing reliance on polluting fossil fuels and developing clean, cost-effective and reliable solutions to power homes and businesses.

Land-based and Offshore Wind Capacity Additions. The EDF Scenario assumes 800 MW of offshore wind begins operation in 2031, and an incremental 850 MW of additional new capacity is added each year from 2032-2035.²¹ In total, the EDF Scenario includes 2,500 MW of offshore wind by 2033, and about 4,200 MW by 2035. As discussed in detail in Josh Kaplowitz’s filed testimony on behalf of EDF, the average approximate lead time for the first six commercial U.S. offshore wind projects is expected to be between six and seven years,²² which should make it feasible to deliver this level of offshore wind capacity in North Carolina by 2033 and 2035. Further, the EDF Scenario also assumes 1,200 MW of new incremental land-based wind capacity added by 2033 in increments of 400 MW each year between 2031-2033, and a further 600 MW beginning operation by 2038, adding up to 1,800 MW of total new land-based wind capacity by 2038. Total new wind capacity under the EDF Scenario reaches 5,640 MW in 2035, exceeding both the Companies Stipulation and Public Staff’s NTAP scenarios primarily as a result of greater offshore wind capacity. By 2035, the Companies Stipulation includes a total of 4,500 MW of

¹⁸ Direct Testimony of Edward Burgess, Expert Witness for the Attorney General’s Office, Docket E-100, SUB 190 at 14.

¹⁹ See Lazard, *Levelized Cost of Energy+* (June 2024), <https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-vf.pdf>.

²⁰ See NREL, *Utility-Scale PV-Plus-Battery*, https://atb.nrel.gov/electricity/2023/utility-scale_pv-plus-battery

²¹ This outlook factors in the recent change in ownership of the Kitty Hawk North lease area.

²² Josh Kaplowitz testimony, Before the North Carolina Utilities Commission, Docket No. E-100, SUB 190, May 28, 2024.

land-based and offshore wind capacity. Public Staff envisions 4,000 MW of total wind capacity in its NTAP by 2035.

The higher levels of wind resources included in the EDF Scenario are supported by several major factors. First, similar to solar energy, both land-based and offshore wind are becoming increasingly cost-effective and available resources. Between 2009 and 2024, the levelized cost of energy (LCOE) of land-based wind declined by 65% making land-based wind resources cost-competitive with combined cycle natural gas power plants under most circumstances.²³ Offshore wind, which has a much shorter history in the U.S. with the first offshore wind project going online as recently as 2016,²⁴ is also projected to see cost declines going forward, resulting in cost savings for electricity customers.²⁵ For example, Dominion Energy Coastal Virginia Offshore Wind (CVOW), a 2,600 MW offshore wind project, is projected to generate fuel cost savings of about \$300 million per year, when fully operational in 2026.²⁶ In the Northeast, where states are coordinating regional transmission planning to promote the deployment of offshore wind,²⁷ analysis suggests that by deploying 9,000 MW of offshore wind capacity by 2030, customers could save up to \$1.3 billion per year when the resources come online.²⁸

Second, North Carolina is estimated to have significant wind potential, particularly along its coastal areas, which are characterized by high-intensity winds and ideal for developing wind farms.²⁹ Output from potential offshore resources alone could amount to about five times North Carolina's total electricity needs.³⁰

Finally, development of wind projects also has significant potential to deliver many economic benefits to North Carolina outside of the electricity services it could provide, including direct and indirect employment, land lease income, and local tax revenue. One recent study found that development of 2,800 MW of offshore wind capacity (well below the level assumed under the EDF Scenario considered in this whitepaper) off the North Carolinian coast would create 10,000 jobs over a three-year construction period, 900 jobs in operations and maintenance, and deliver nearly \$5 billion in net economic value to the state.³¹

Duke rightly included offshore wind in its projections, but set an unnecessarily slow pace of development for the resource and fails to consider full build out of lease areas already approved by the federal government off North Carolina's coast. Duke's relatively limited consideration of offshore wind potential

²³ See note 19.

²⁴ See Tatiana Schlossberg, *America's First Offshore Wind Farm Spins to Life*, <https://www.nytimes.com/2016/12/14/science/wind-power-block-island.html>

²⁵ See NREL, *Offshore Wind*, https://atb.nrel.gov/electricity/2023/offshore_wind

²⁶ See Virginia Economic Development Partnership, *Charting a Cleaner Energy Future for Virginia: A Conversation With Bob Blue*, <https://www.vedp.org/news/charting-cleaner-energy-future-virginia-conversation-bob-blue>

²⁷ See [MOU-Northeast-States-Collaborative-on-Interregional-Transmission.pdf](https://www.nrel.gov/docs/fy22osti/83650.pdf) (jhu.edu)

²⁸ See Diana DiGangi, *9 GW of offshore wind could save New England ratepayers \$630M on average a year: report*, <https://www.utilitydive.com/news/new-england-offshore-wind-deployment-bill-customer-electricity/718190/>

²⁹ See NREL, *Wind Resource Maps and Data*, <https://www.nrel.gov/gis/wind-resource-maps.html> and Anthony Lopez et al., *Offshore Wind Energy Technical Potential for the Contiguous United States*, <https://www.nrel.gov/docs/fy22osti/83650.pdf>

³⁰ See Bryn Huxley-Reicher and Hannah Read, *Offshore Wind for America: The promise and potential of clean energy off our coasts*, https://environmentamerica.org/wp-content/uploads/2022/07/AME_Offshore-Wind-For-America_2021-1.pdf

³¹ See Simmons et al., *North Carolina Offshore Wind Cost-Benefit Analysis*, https://e2.org/wp-content/uploads/2022/01/NC_Offshore_Wind_Cost-Benefit_Analysis_FINAL.pdf

in its analysis misses a significant opportunity to invest in clean energy for the early- to mid-2030 timeframe and deliver climate, public health and economic benefits to its customers in North Carolina.³²

This will be a critical period for at least two reasons: the pace and direction for decarbonization through the remainder of the 2030 decade and towards carbon neutrality in 2050 will be set based on decisions taken during this period, and electricity demand could grow at a faster rate than expected, as Duke predicts in its Supplemental filing. In addition, accelerating clean energy investments throughout the country will begin to deliver major environmental, public health, and economic benefits. By not leveraging North Carolina's wind resource potential fully, the Companies Stipulation scenario could deprive North Carolina of significant broader economic benefits between now and 2050.

VI. Additional Potential Issues in Duke's Modeling Analysis

There are a range of additional factors and assumptions in the Duke modeling analysis that likely skew the outcomes heavily towards building new gas plants. These will be summarized briefly in this section. The sources referenced in the discussion below contain greater detail.

Load Forecast. The most pronounced change in the Fall supplemental analysis was the adjustment of the load forecast to account for anticipated additional demand driven by data centers, battery manufacturing facilities, and other economic development. The revised Companies plan envisioned a 5% increase in the 2038 winter peak forecast and a 12% increase in 2038 energy demand.³³ The Companies also analyzed an even higher demand case to recognize the potential for "mega projects" sites that have not yet made material commitments for inclusion in the updated Fall 2023 load forecast.

While this analysis does not attempt to provide alternative load estimates, Duke's analysis would have benefitted from the inclusion of a lower demand scenario that moderates the sharp demand increase on the basis that not all of the anticipated demand centers begin operations and that there may be technology efficiency gains that reduce load even if these resource additions do materialize. Load forecasting, particularly beyond one year, can be uncertain and imprecise. Duke should have considered at least one lower load scenario to help describe a range of possible portfolio outcomes, particularly because of the significant gap between the load assumptions in P3 Fall Base and the Fall supplemental analysis.

The downside effect of overestimating energy and peak loads is that a resulting projection would build or add excess capacity than what is necessary. This would translate to higher costs for ratepayers for assets that could be dispatched only minimally or not at all, increasing stranded asset risk for both the Companies and their customers. (See Box on "Resource Adequacy Requirements" for additional discussion.)

Public Staff witnesses John Hinton and Patrick Fahey address these issues and offer an alternative load forecast in their filed testimony.³⁴ Additionally, the filed testimony of James F. Wilson of the Southern

³² For a more detailed discussion see Will Scott, *North Carolina Carbon Plan: Why Duke's gas bet is a risk to ratepayers and how offshore wind can carry the load*, <https://blogs.edf.org/climate411/2024/06/17/north-carolina-carbon-plan-why-dukes-gas-bet-is-a-risk-to-ratepayers-and-how-offshore-wind-can-carry-the-load/>

³³ See Duke Energy, *Supplemental Planning Analysis*, <https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/supplements/supplemental-planning-analysis.pdf?rev=f134d62ba6d645ccb3de2bc227a0d42d>

³⁴ Hinton and Fahey testimony, Before the North Carolina Utilities Commission, Docket No. E-100, SUB 190, May 28, 2024. Joint Testimony of John R. Hinton and Patrick A. Fahey Public Staff – North Carolina Utilities Commission.

Alliance for Clean Energy³⁵ discusses load forecasting, reaching similar conclusions and also offers alternative load forecasts that take a more moderate view of growth in the DEC and DEP footprints.

Solar capacity limits and technology cost adders. Duke's capacity expansion analysis in the initial Resource Plan limits new solar capacity additions to 1,350 MW per year from 2028-2030, and 1,575 MW per year beginning in 2031. The latter restriction was revised to 1,800 MW per year starting in 2032 in the Supplemental Planning Analysis. However, the Supplemental Planning Analysis did not modify the 2028-2030 build limits. This arbitrary limit on the most cost-effective new generating resource is overly restrictive and likely constrains the modeling analysis to a presumed outcome.

Additionally, Duke assumes a 20% capital cost adder on new wind, solar and battery capacity additions, making them more costly relative to other resources, specifically natural gas, in the analysis. Because of the limiting assumptions and characterizations of new solar capacity that Duke has incorporated into its analysis, along with the elevated electricity demand levels, the model is capacity-constrained, meaning that it must add resources to meet the requirements of demand. Duke's assumptions create the impression that the system needs significant additional capacity and consequently must add as much CC and CT as possible. From a modeling perspective, new solar is costly (because of the cost adders) and there is not enough available (because of the hard limits indicated above) to address the demand requirements compared with both new gas combined cycle and new gas combustion turbine, which are unlimited and are not subject to the cost adders. New gas plants are essentially the only option for new generating capacity that the model is left with. The limiting assumptions on new solar effectively preordain the model to selecting natural gas.

Energy efficiency and demand response. Duke's analysis may not have considered the full potential of energy efficiency, demand response, distributed energy resources (DERs) and other demand-side services in meeting resource needs. Its implications for the analysis and planning process is covered in the direct testimony of Southern Alliance for Clean Energy (SACE) witness Jake Duncan.³⁶ To summarize, DERs and demand-side resources can be integrated quickly, reduce customer bills, moderate load during certain critical times, reduce emissions, and provide grid services. His testimony suggests that Duke's analysis may not have included behind-the-meter storage, distributed resource planning, or time of use EV rates, therefore violating the least cost planning principle and failing to account for all factors that could reduce peak load. Expert witness Duncan's testimony goes on to recommend that the Commission require Duke to consider these resources across the DEC and DEP footprint in order to comprehensively consider all aspects affecting load on the system.

The combination of these assumptions and approaches skews Duke's planning in favor of gas resources and discounts the value and grid services that clean resources can provide. As a consequence, it potentially puts customers at risk of covering costs of future stranded assets with the significant opportunity cost of foregoing nearly 35 million of tons of CO₂ emissions reductions from building clean resources sooner.

³⁵ James F. Wilson testimony, Before the State of North Carolina Utilities Commission, Docket No. E-100, SUB 190, May 28, 2024. Direct Testimony and Exhibits of James F. Wilson on behalf of Southern Alliance for Clean Energy, Sierra Club, Natural Resources Defense Council, and North Carolina Sustainable Energy Association.

³⁶ Jake Duncan testimony, before the North Carolina Utilities Commission, Docket NO. E-100, SUB 190, on behalf of The Southern Alliance for Clean Energy, The Natural Resources Defense Council, The Sierra Club, and The North Carolina Sustainable Energy Coalition, May 28, 2024.

<https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=75c81625-4b7d-4d56-9c5f-b6594d63a1bf>

VII. Conclusion

This white paper and the analysis of the EDF Scenario show that Duke’s supplemental analysis and the Companies Stipulation do not capture all the opportunities for investment in clean technologies while minimizing impacts on homes and businesses. Duke’s IRP analysis does not explore the full range of options available to meet the changing needs of the DEP and DEC footprint. A different set of potentially more realistic assumptions and analytical methods would have introduced a broader array of resource technologies sooner in Duke’s modeling, which could have led to a range of proposals with lower CO₂ emissions projections. Such an approach, as represented in the EDF portfolio would reduce CO₂ emissions from the DEP and DEC fleets by 7.5%, or 36.4 million tons, on a cumulative basis between 2024-2038 compared with the Companies Stipulation scenario and would deliver a lower risk path in terms of both CO₂ emissions and potential stranded assets.

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For questions or comments, please contact:

Alison Wenzel
Senior Communications Specialist
awenzel@edf.org

Lead Authors:

Starla Yeh
Chandler LLC
starla.l.yeh@gmail.com

Starla directed Policy Analysis at Natural Resources Defense Council (NRDC) for more than a decade, focusing primarily on climate and energy policy at the federal and state levels. She has developed innovative analyses which have been directly relied upon by various stakeholders to identify policy design approaches. Additionally, she has advised on economy-wide climate target-setting and long-term emissions outlooks. She holds a bachelor’s degree in economics from DePauw University, and a JD from Vermont Law School.

Amlan Saha
PT Strategy & Intelligence LLC
asaha@ptstrategy.com

Since 2006 Amlan has advised clients on a range of climate and energy issues, including power plant economics and the impacts of regulation on the financial viability of energy resources. He has also built carbon pathway models that utilities have used to conduct climate scenario analyses. He holds a bachelor’s degree in engineering from the National University of Singapore, an MBA from L’Ecole des Hautes Etudes Commerciales (HEC Paris), and a master’s degree in law and diplomacy from the Fletcher School at Tufts University.

Contributors:

Will Scott, EDF
Ian Lloyd, EDF
David Kelly, EDF
**Benjamin Smith, Kilpatrick
Townsend & Stockton LLP**