

**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO E-100, SUB 207**

In the Matter of:	)	
2025 Biennial Consolidated Carbon Plan and	)	
Integrated Resource Plans of Duke Energy	)	DIRECT TESTIMONY OF
Carolinas, LLC, and Duke Energy Progress, LLC,	)	DEVI GLICK ON BEHALF
Pursuant to N.C.G.S. §§ 62-2(a)(3a), 62-110.1,	)	OF NORTH CAROLINA
62-110.9, and Commission Rule R8-60A	)	SUSTAINABLE ENERGY
	)	ASSOCIATION
	)	

March 30, 2026

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I INTRODUCTION AND PURPOSE OF TESTIMONY

Q PLEASE STATE YOUR NAME AND OCCUPATION.

A My name is Devi Glick. I am a Senior Principal at Synapse Energy Economics, Inc. ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q PLEASE DESCRIBE SYNAPSE ENERGY ECONOMICS.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q PLEASE SUMMARIZE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, electric system dispatch, integrated resource planning, environmental compliance technologies and strategies, and valuation of distributed energy resources. I have submitted expert testimony before state utility regulators in over 60 litigated proceedings across 20 states.

1
2 In the course of my work, I develop in-house models and perform analysis using
3 industry-standard electricity power system models. I am proficient in the use of
4 spreadsheet analysis tools, as well as optimization and electric dispatch models. I
5 have directly run EnCompass and PLEXOS and have reviewed inputs and outputs
6 for several other models.

7
8 Before joining Synapse, I worked at RMI, focusing on a wide range of energy and
9 electricity issues. I have a master's degree in public policy and a master's degree in
10 environmental science from the University of Michigan, as well as a bachelor's
11 degree in environmental studies from Middlebury College. I have more than 12
12 years of professional experience as a consultant, researcher, and analyst. A copy of
13 my current resume is attached as **Exhibit DG-1**.

14 **Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?**

15 A I am testifying on behalf of the North Carolina Sustainable Energy Association
16 ("NCSEA").

17 **Q HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH**
18 **CAROLINA UTILITIES COMMISSION ("COMMISSION")?**

19 A Yes, I submitted testimony in Docket No. E-2, Sub 1272 and Docket No. E-7, Sub
20 1250—fuel adjustment clause proceedings pertaining to Duke Energy Carolinas,
21 LLC ("DEC") and Duke Energy Progress, LLC ("DEP," collectively with "DEC,"
22 "Duke Energy" or the "Companies")—and Docket No. E-100, Sub 158—the 2018
23 *Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from*

1 *Qualifying Facilities*. I also appeared on behalf of NCSEA as a presenter at the
2 October 14, 2025, technical conference associated with Docket No. E-100, Sub
3 208.

4 **Q WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS**
5 **PROCEEDING?**

6 A In this proceeding, I review Duke Energy’s 2025 Biennial Consolidated Carbon
7 Plan and Integrated Resource Plan (“CPIRP”) and evaluate its input assumptions,
8 modeling methodology, and final portfolios. I assess the reasonableness of the
9 Companies’ proposed resource build and demand-side management (“DSM”) and
10 energy efficiency investment plans. I assess whether the Companies are accurately
11 reflecting the costs, risks, and volatility impacts of its planned reliance on gas
12 resources through its modeling. I then present the results of NCSEA’s alternative
13 analyses. Both the NCSEA Alternative Portfolio and the NCSEA Combined Utility
14 Portfolio represent least-regrets futures that meet the energy and reliability needs
15 of the Companies’ high and growing load forecast with fewer new gas generation
16 resources and increased investment in energy efficiency. The NCSEA portfolios
17 maintain a viable path to the 2050 net-zero carbon emissions requirement and result
18 in a lower cost to ratepayers than Duke Energy’s Recommended Portfolio.

19 **Q HOW IS YOUR TESTIMONY STRUCTURED?**

20 A My testimony is structured as follows:

- 21 • In Section 2, I summarize my findings and recommendations for the
22 Commission.

- 1 • In Section 3, I summarize Duke Energy’s resource plan modeling framework,
2 replacement resources considered, and modeling results.
- 3 • In Section 4, I present the results of NCSEA’s alternative analyses. I describe
4 my modeling tools and their capabilities. I describe the scenarios and
5 sensitivities I modeled and outline my input assumptions with a focus on where
6 my assumptions aligned with Duke Energy’s and where they differed. I present
7 the results of the NCSEA Alternative Portfolio and the NCSEA Combined
8 Utility Portfolio to show how my results compare to the results the Companies
9 presented. I explain the drivers of the differences between Synapse’s modeling
10 results and Duke Energy’s.
- 11 • In Section 5, I provide more context and detail on the challenging issues facing
12 Duke Energy in this CPIRP: these include the risk and cost to existing
13 ratepayers of building to meet new large load and regulatory and fuel price
14 volatility risks from continued reliance on fossil resources and new nuclear
15 resources.

16 **Q WHAT INFORMATION DO YOU RELY UPON FOR YOUR ANALYSIS,**
17 **FINDINGS, AND OBSERVATIONS?**

18 A My analysis relies primarily on the workpapers, exhibits, and discovery responses
19 of Duke Energy’s witnesses. I also rely on other publicly available documents and
20 data, which I cite throughout my testimony.

21 **Q ARE YOU SPONSORING ANY EXHIBITS?**

22 A Yes. I am sponsoring the following exhibits:

23

Exhibit Number	Description of Exhibit
Exhibit DG-1	Resume of Devi Glick
Exhibit DG-2	Duke Energy Response to NCSEA DR 3-11
Exhibit DG-3	Duke Energy Corrected Response to PSDR 6-13 (Attachment PSDR6-13 - Corrected 10.29.25.xlsx)

II FINDINGS AND RECOMMENDATIONS

Q PLEASE SUMMARIZE YOUR FINDINGS.

A My primary findings are the following:

1. Relative to Duke Energy’s Recommended Portfolio in its 2023 CPIRP, in the 2025 edition of its Recommended Portfolio, Duke Energy is scaling back the Companies’ planned investment in solar photovoltaics (“PV”) in the Near-Term Action Plan (“NTAP”)—identifying near-term (2026–2028) and intermediate-term (2029–2034) actions—while increasing its investment in battery energy storage and natural gas generation. Specifically, Duke Energy is proposing to:
 - a. reduce investment in solar PV by 2,460 MW;
 - b. increase its planned investment in battery energy storage by 1,900 MW; and
 - c. increase its planned investment in new gas generation resources by 700 MW.¹

¹ See 2025 Carolinas Resource Plan, Ch. 4 – Execution Plan, Dkt. No. E-100, Sub 207, 10–11 (Oct. 1, 2025) (Table 4-2: NTAP Table – 2026-2028 Actions for New Supply-Side Resources, enumerating changes to NTAP.).

- 1 2. Duke Energy’s projections around load growth between now and 2040—
2 which have increased by more than 2,000 MW since its last CPIRP in
3 2023—are driving the Companies to push the retirement dates for its
4 existing coal plants as far out as 2040 and to plan to build over 12 GW of
5 new combined cycle and combustion turbine gas plants between now and
6 2040.
- 7 3. Duke Energy relies on overly optimistic parameters for large light water
8 reactor (“LLWR”) nuclear costs and timelines and is exposing customers to
9 risk by relying on this technology.
- 10 4. Duke Energy does not currently have sufficient firm gas capacity to serve
11 its planned gas generation resources and instead relies on a product it calls
12 enhanced liquified natural gas (“ELNG”) to provide firm capacity for its
13 gas plants when existing firm transport options have been exhausted. ELNG
14 is an immature technology, and it is uncertain whether ELNG can provide
15 firm gas supply and moderate fuel price volatility effectively on the timeline
16 and at the cost Duke Energy modeled.
- 17 5. Duke Energy’s relatively low level of planned DSM investment in its
18 Recommended Portfolio—including energy efficiency programs and
19 demand response programs, as well as the PowerPair storage program—
20 results in higher load and a more expensive system than an alternative
21 portfolio with higher levels of DSM investment.
- 22 6. Duke Energy failed to pursue reasonable development activities to develop
23 Bad Creek II pumped-hydro storage facility (“Bad Creek II”). This inaction

unreasonably delayed the deployment timeline for Bad Creek II, a resource assumed to come online in 2034 in Duke Energy's Recommended Portfolio in its 2023 CIPRP. Bad Creek II represents a mature long-duration storage resource that can help to defer investment in more expensive, riskier technologies such as LLWR nuclear and gas firming with ELNG.

7. The NCSEA Alternative Portfolio, which includes increased investment in energy efficiency, DSM, expanded PowerPair program resources, and the addition of Bad Creek II in 2037, results in less natural gas and fewer nuclear resources than in Duke Energy's Recommended Portfolio.

8. Based on NCSEA's Strategic Energy and Risk Valuation ("SERVM") modeling, the NCSEA Alternative Portfolio achieves Duke Energy's reliability threshold.

9. Under Duke Energy's Combined Utility assumptions, the NCSEA Alternative Portfolio results in a lower system cost than under Duke Energy's Recommended Portfolio.

Q WHAT ARE YOUR RECOMMENDATIONS BASED ON THOSE FINDINGS?

A Based on those findings, I have the following recommendations:

1. Duke Energy should revise its Recommended Portfolio and its NTAP by:
 - a. incorporating higher levels of energy efficiency and DSM investment, more aligned with levels modeled in its high energy efficiency and high DSM scenarios;

b. modeling accelerated and increased deployment of the PowerPair program; and

c. including Bad Creek II as a resource in the late 2030s.

2. Duke Energy should regularly monitor the cost of maintaining its legacy coal resources, and it should update its retirement plans accordingly since costly investments would be required to keep plants operational.

3. Duke Energy should better justify its firm gas supply and ELNG assumptions by providing detailed public sources that provide support for the cost, timeline, and availability of the firm gas supply assumptions it models.

4. Duke Energy should better justify its assumptions for LLWR costs and timing, especially in light of analogous resources built in the southeastern United States.

III DUKE ENERGY'S MODELING AND RECOMMENDED PORTFOLIO

Q WHAT ARE THE MAJOR THEMES OF THIS CPIRP, AND WHAT WAS YOUR FOCUS FOR ANALYSIS?

A As with its prior 2023 CPIRP, Duke Energy's current 2025 CPIRP focuses on the challenges of meeting growing load, which is driving the need for new energy and capacity resources. This growing resource need is driving Duke Energy to keep its existing coal resources online longer than previously planned and to build new gas resources. Another major theme is reliance on a firm natural gas supply and the Companies' modeling and evaluation of a product it refers to as ELNG as an alternative to firm pipeline capacity. Another theme is new technologies, and

1 specifically, Duke Energy's consideration of long-lead generation resources such
2 as small modular nuclear reactors ("SMR"), LLWRs, and Bad Creek II. Finally, in
3 my analysis I evaluate the Companies' consideration of demand-side alternatives,
4 including energy efficiency and demand response resources and battery resources
5 available through the PowerPair program, as part of its Recommended Portfolio.

6 **Q WHICH OF DUKE ENERGY'S SCENARIOS DO YOU FOCUS ON FOR**
7 **YOUR ANALYSIS?**

8 A My testimony focuses on the Companies' Preliminary Base Portfolio and the
9 Recommended Portfolio.

10 A **Duke Energy's modeling methodology and results**

11 **Q EXPLAIN DUKE ENERGY'S MODELING METHODOLOGY.**

12 A Duke Energy first conducts three preliminary evaluations to determine inputs for
13 fuel security, nuclear technology, and coal retirement dates. Duke Energy uses that
14 information to set up its capacity expansion modeling in the EnCompass model to
15 determine its Preliminary Base Portfolio. Duke Energy then conducts capacity
16 expansion and production cost modeling in EnCompass for 30 sensitivities, each
17 one featuring a single modified input relative to the Preliminary Base Portfolio.
18 Using results from the Preliminary Base Portfolio and the sensitivities, Duke
19 Energy determines capacity additions through 2034 to include in its NTAP, taking
20 into account what it calls "quantitative modeling results and qualitative assessment
21 of execution and risk factors."² Duke Energy then runs the NTAP scenario through

² 2025 Carolinas Resource Plan, Ch. 3 – Portfolio Development & Evaluation, Dkt. No. E-100, Sub 207, 3 (Oct. 1, 2025).

1 EnCompass to allow for economic selection of new resources in the remaining
2 modeling period. Duke Energy refers to the resources resulting from this modeling
3 step as the Recommended Portfolio. Using data from the EnCompass model, Duke
4 Energy calculates revenue requirement and present value of revenue requirement
5 (“PVRR”) for each of its portfolios and calculates bill impacts for select portfolios.
6 Finally, Duke Energy uses the SERVIM model, a reliability assessment model, to
7 determine the reliability of its Preliminary Base Portfolio, Recommended Portfolio,
8 and a selection of sensitivities.

9 **Q DESCRIBE DUKE ENERGY’S PRELIMINARY EVALUATIONS USED**
10 **TO DEVELOP THE ASSUMPTIONS FOR ITS PRELIMINARY BASE**
11 **PORTOFLIO.**

12 A Duke Energy conducts three preliminary evaluations to determine inputs and
13 assumptions, ahead of performing capacity expansion analysis:

- 14 • Fuel Security Evaluation: First, Duke Energy uses EnCompass to evaluate firm
15 interstate pipeline capacity against ELNG to assess the most economic fuel
16 security option to provide fuel to incremental combined cycle units.³ Duke
17 Energy finds that ELNG is the most economic fuel security option and proceeds
18 to set that type of resource as a selectable option in its capacity expansion
19 analysis.⁴

³ See 2025 Carolinas Resource Plan, App’x C – Quantitative Analysis, Dkt. No. E-100, Sub 207, 42 (Oct. 1, 2025).

⁴ See 2025 Carolinas Resource Plan, App’x I – Natural Gas & Low-Carbon Fuels, Dkt. No. E-100, Sub 207, 7 (Oct. 1, 2025).

- 1 • Nuclear Technology Selection: Next, Duke Energy uses EnCompass to evaluate
- 2 SMR against LLWR technology. Through its evaluation, Duke Energy selected
- 3 the LLWR resource to be the generic nuclear technology for model selection.⁵
- 4 • Coal retirement analysis: Third, Duke Energy uses EnCompass to optimize coal
- 5 plant retirement dates by comparing the projected cost of maintaining coal units
- 6 with the cost of replacing them with resources that will maintain minimum
- 7 system reliability requirements.⁶

8 The results of these three evaluations are then used to inform later EnCompass
9 modeling steps.

10 **Q HOW DOES DUKE ENERGY DEVELOP ITS KEY INPUTS?**

11 A Duke Energy's key inputs include its load forecasts; supply-side and demand-side
12 resource options, costs, and operational parameters; reliability requirements;
13 system topology planning assumptions; fuel prices; and regulations and
14 requirements. Duke Energy developed four load forecasts: Advancing
15 Development, Moderate Development, Low, and High. The different forecasts
16 adjust economic development assumptions, the base economic forecast, electric
17 vehicle adoption, and behind-the-meter solar generation.⁷ Supply-side resources
18 include existing resources, existing resource retirements, existing resource capacity
19 uprates, planned expiration of capacity power purchase agreements, and generic
20 resources that represent each resource type to allow for new resource builds during

⁵ See 2025 Carolinas Resource Plan, App'x C, at 43.

⁶ See 2025 Carolinas Resource Plan, App'x C, at 45; see also 2025 Carolinas Resource Plan, App'x F – Coal, Dkt. No. E-100, Sub 207, 9 (Oct. 1, 2025).

⁷ See 2025 Carolinas Resource Plan, App'x C, at 15–16.

1 the capacity expansion timeframe.⁸ Demand-side resources include demand
2 response customer programs and energy efficiency. The low, base, and high energy
3 efficiency forecasts are based on increasing amounts of energy savings.⁹ Duke
4 Energy also develops price forecasts for natural gas and coal based on market
5 prices.¹⁰ Duke Energy prepares three model topologies: consolidated system
6 operations/hybrid, utility combination, and the two-utility alternative. Each
7 topology differs in reserve margin planning, unit commitment, unit dispatch,
8 operating reserve, resource siting constraints, and/or approach towards meeting the
9 carbon neutrality target. The utility combination topology is intended to represent
10 a future in which DEP and DEC combine into one utility. In that topology, the
11 combined utility meets topology-related assumptions jointly.¹¹

12 **Q HOW DOES DUKE ENERGY DEVELOP ITS PRELIMINARY BASE**
13 **PORTFOLIO?**

14 A Duke Energy's Preliminary Base Portfolio consists of its baseline planning
15 assumptions and the input decisions determined by the Companies' preliminary
16 evaluations. The Preliminary Base Portfolio uses Duke Energy's Advancing
17 Development Load forecast, base demand response and energy efficiency
18 quantities, base fuel prices, base resource costs, and consolidated system
19 operations/ hybrid utility topology assumptions. The base energy efficiency
20 forecast assumes energy efficiency savings equal to one percent of eligible retail

⁸ *Id.*, at 19–21.

⁹ *Id.*, at 17–18, 21–22.

¹⁰ *Id.*, at 39, 41.

¹¹ *Id.*, at 9–11.

1 load.¹² Duke Energy's base demand response quantities are based on expected
2 participation across all programs.¹³

3 **Q DESCRIBE DUKE ENERGY'S SENSITIVITY SCENARIOS.**

4 A Duke Energy tests 30 sensitivities that evaluate risk, uncertainties, and tradeoffs for
5 the following inputs: load, DSM, natural gas price, resource cost, resource
6 availability, and utility combination assumptions. In each sensitivity, Duke Energy
7 changes inputs related to a single assumption in the Preliminary Base scenario.
8 Duke Energy does not model any sensitivity where multiple inputs are changed
9 simultaneously to evaluate their combined effect. The result is 30 sensitivity
10 analysis portfolios.

11 **Q HOW DOES DUKE ENERGY DEVELOP ITS NTAP?**

12 A Duke Energy manually constructs its NTAP based on the results of the Preliminary
13 Base Portfolio and sensitivity analysis portfolios. To do this, Duke Energy takes
14 into account what it calls "quantitative modeling results and qualitative assessment
15 execution and risk factors."¹⁴ In practice, I observe that Duke Energy selects
16 resources for the NTAP based on how often it sees resources selected in sensitivity
17 analysis portfolios. Resources selected in more sensitivity portfolios are considered
18 more likely outcomes.

¹² *Id.*, at 17.

¹³ *Id.*, at 22.

¹⁴ 2025 Carolinas Resource Plan, Ch. 3, at 3.

1 **Q WHICH RESOURCES DOES DUKE ENERGY INCLUDE AS FIXED**
2 **ADDITIONS IN THE NTAP?**

3 A In its NTAP, Duke Energy exogenously includes—meaning it forces the model to
4 select—4,000 MW of solar, 5,600 MW of battery storage, 2,825 MW of gas-fired
5 combustion turbines, and 6,825 MW of combined cycle gas plants by 2034. The
6 NTAP consists of capacity additions through 2034 that Duke Energy selects
7 entirely outside of the EnCompass model.

8 **Q HOW DOES DUKE ENERGY DEVELOP ITS RECOMMENDED**
9 **PORTFOLIO?**

10 A To develop its Recommended Portfolio, Duke Energy starts with the NTAP
11 Portfolio and uses the EnCompass capacity expansion feature to endogenously
12 select—meaning the model is allowed to economically optimize and select—
13 resources outside of the NTAP. Capacity additions beyond 2034 are cost-
14 effectively determined by EnCompass in the Recommended Portfolio. Duke
15 Energy also uses EnCompass to run production cost modeling and cost-effectively
16 dispatch resources. Because the Recommended Portfolio is based on an
17 exogenously set portfolio of resources in the near term, it is not cost-optimized and
18 may not be least cost for ratepayers. These near-term selections may also influence
19 the model’s long-term decision-making, preventing least cost outcomes over the
20 entirety of the study period.

1 **Q WHAT RESOURCES DOES DUKE ENERGY ADD TO ITS SYSTEM IN**
 2 **THE RECOMMENDED PORTFOLIO?**

3 A Table 1 below shows the annual resource additions by resource type in Duke
 4 Energy's Recommended Portfolio. Duke Energy plans to add 10.4 GW of solar
 5 throughout the study period, not including 4.7 GW of solar currently under
 6 development. It also plans to add 3.4 GW of nuclear, 8.4 GW of storage (in addition
 7 to 1.0 GW of battery under development), 4.1 GW of natural gas combustion
 8 turbines, and 8.2 GW of combined cycle plants. The model portfolio includes no
 9 changes to wind or pumped hydro storage resources.

10 **Table 1. Annual capacity additions in Duke Energy's Recommended Portfolio (MW)¹⁵**

Year	Coal	Solar	Battery	Natural Gas CT	Natural Gas CC	Nuclear	Wind	Pumped Storage
2028	-	-	500	-	-	-	-	-
2029	-1,851	-	1,000	856	1,365	-	-	-
2030	-	825	600	1,111	1,365	-	-	-
2031	-713	825	500	-	1,365	-	-	-
2032	-	750	500	856	1,365	-	-	-
2033	-546	825	600	-	1,365	-	-	-
2034	-2,369	825	800	-	-	-	-	-
2035	-	450	1,000	-	-	-	-	-
2036	-	1,200	900	-	-	-	-	-
2037	-	1,050	1,000	-	-	1,117	-	-
2038	-	1,200	1,000	-	-	1,117	-	-
2039	-	1,200	-	-	-	-	-	-
2040	-2,220	1,200	-	1,284	1,365	1,117	-	-
Total	-8,019	10,350	8,400	4,107	8,190	3,351	-	-

11 *Note: Annual resource additions shown here do not include 4,686 MW of solar and 1,040 MW of*
 12 *battery that are under development and included in all portfolios as forecasted resources. "CC" is*
 13 *combined cycle. "CT" is combustion turbine.*

¹⁵ See 2025 Carolinas Resource Plan, App'x C, at 97 (aggregating the annual resource additions and coal retirements (nameplate MW) identified in the Companies' Table C-49 and Table C-50).

1 **Q HOW DOES DUKE ENERGY CONDUCT ITS RELIABILITY**
2 **VERIFICATION MODELING?**

3 A Duke Energy uses the SERVVM model to conduct reliability verification modeling
4 for benchmark years 2035 and 2040 across the following portfolios: Preliminary
5 Base, Moderate Development Load, Low Cost Battery, High Solar and Storage
6 Availability, Accelerated Renewables, and Recommended Portfolio.¹⁶ For each
7 portfolio, Duke Energy uses SERVVM to evaluate hourly system operations across
8 45 weather years, 50 forced-outage scenarios, and three load forecast outcomes for
9 a total of 6,570 combined weather, forced-outage, and load forecast iterations. Duke
10 Energy reports probability-weighted average results for four metrics: loss of load
11 expectation (“LOLE”), loss of load hours (“LOLH”), expected unserved energy
12 (“EUE”), and normalized expected unserved energy (“nEUE”).

13
14 To translate each EnCompass portfolio into SERVVM, Duke Energy uses
15 EnCompass “Resource Monthly” outputs with adjustments for solar and storage
16 units. Duke Energy conducts each SERVVM study as an “islanded” study, without
17 market assistance from neighboring utilities. Duke Energy designates combustion
18 turbine units as the firm capacity reliability resource, adding them to each portfolio
19 until it meets an islanded LOLE target of 0.165 consistent with Duke Energy’s 2023
20 Resource Adequacy Study (as a proxy for the standard 0.1 LOLE threshold).¹⁷ This

¹⁶ See 2025 Carolinas Resource Plan, App’x C, at 73–76.

¹⁷ *Id.*, at 75.

1 only results in combustion turbine additions to the Low Battery Cost and High Solar
2 and Storage Availability portfolios for 2035.

3 **Q HOW DOES DUKE ENERGY CALCULATE ITS REVENUE**
4 **REQUIREMENT AND PRESENT VALUE OF REVENUE**
5 **REQUIREMENT?**

6 A Duke Energy calculates revenue requirement in a post-processing step using results
7 from its EnCompass production cost modeling combined with hard-coded values
8 calculated outside the EnCompass model. These additional values include coal
9 plant fixed operation and maintenance (“FOM”) and capital expenditures; existing
10 nuclear fixed costs; battery storage FOM; solar and solar plus storage power
11 purchase agreement (“PPA”) costs; energy efficiency, demand response, and
12 Integrated Volt-VAR Control (“IVCC”) program costs; and investment tax credits
13 (“ITC”).

14 **Q HOW DOES DUKE ENERGY CALCULATE ITS BILL IMPACT RESULTS**
15 **FOR RESIDENTIAL CUSTOMERS?**

16 A Duke Energy uses a simplified method to develop bill impacts for residential
17 customers. Rather than allocating revenue requirements to each customer class,
18 Duke Energy assumes that the revenue requirement for residential customers grows
19 at the same rate as the revenue requirement for the entire system. This is a simplified
20 assumption, because load for the customer classes is growing at different rates (see
21 below for more discussion on the rapid rate of data center load assumed by Duke
22 Energy in its Preliminary Base and NTAP scenarios). In Duke Energy’s
23 methodology:

[t]he revenue requirements that are used to calculate bill impacts reflect rate making calculations with a depreciating rate base over time (declining revenue requirements for specific resources put into service), utilize incremental O&M from 2026, include retail allocation factors, include CWIP in rate base on nuclear, OSW and combined cycles, include coal securitization benefits and include amortization of the IRA tax credits.¹⁸

For each year, the revenue requirement is then divided by the MWh retail sales to develop dollar-per-MWh rates. Using this, Duke Energy then calculates a cumulative percent increase from 2025 for each of the years through 2040. Next, Duke Energy calculates an illustrative combined DEC/DEP customer bill in 2025 for a typical residential household using 1,000 kWh and the rates in effect during 2025. Finally, the Companies calculate bills in 2035 and 2040 by applying the 2025 typical residential bill to the cumulative percent increase calculated from 2025 to 2040.

B Impact of large load on Duke Energy's inputs and results

Q HOW DOES NEW LARGE LOAD IMPACT DUKE ENERGY'S LOAD FORECAST?

A The Companies currently project that DEC peak load will grow by an average compound annual growth rate ("CAGR") of 2.3 percent from 2026–2040, compared to 1.0 percent in the absence of economic development load (see Figure 1 below, with comparisons summarized in Table 2).¹⁹ Economic development increases peak load in DEC by 2.8 GW in 2030 (an increase of 15.1 percent relative

¹⁸ **Exhibit DG-2**, Duke Energy Response to NCSEA DR 3-11. Note that "CWIP" refers to "construction work in progress," which allows a utility to bill ratepayers for the cost of building utility infrastructure as that infrastructure is in the process of being built.

¹⁹ **Exhibit DG-3**, See Duke Energy Corrected Response to PS DR 6-13 (Referencing the Corrected Attachment PS DR6-13 - Corrected 10.29.25.xlsx).

1 to the 2030 baseline peak load of 18.5 GW) and 4.5 GW by 2040 (an increase of
 2 21.2 percent relative to the 2040 baseline peak load of 21.2 GW).²⁰ Meanwhile, in
 3 DEP, Duke Energy projects peak load will grow by an average CAGR of 1.7
 4 percent from 2026–2040, compared to a 0.6 percent CAGR in the absence of load
 5 from economic development (see Figure 2, below, with comparisons summarized
 6 in Table 2).²¹ Load growth from economic development increases peak load in DEP
 7 by 1.5 GW in 2030 (an increase of 12.3 percent relative to 2030 baseline peak load
 8 of 12.7 GW) and 2.3 GW in 2040 (an increase of 16.8 percent relative to 2040
 9 baseline peak load of 13.8 GW). The Companies states that this load growth
 10 includes only “Advanced Development Projects,” which are economic
 11 development projects with executed ESAs, Letter Agreements (“LA”), or projects
 12 that have progressed to advanced stage discussions prior to signing an ESA or LA.²²
 13
 14 DEC’s 2025 CPIRP load forecast with economic development load by 2037 is 17.7
 15 percent greater than forecasted in the 2022 Initial Carbon Plan and 10.8 percent
 16 greater than forecasted in the 2023 CPIRP.²³ DEP’s peak load forecast with
 17 economic development load by 2037 is 8.8 percent greater than projected in its
 18 2022 CPIRP and 2.1 percent greater than projected in the 2023 CPIRP.²⁴

²⁰ *Id.*

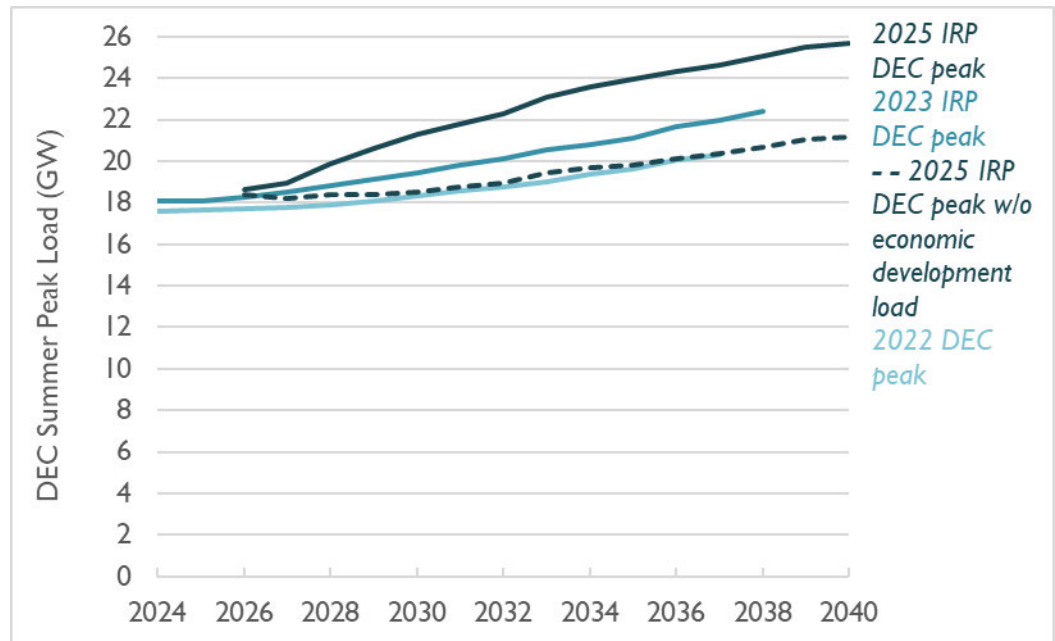
²¹ *Id.*

²² See 2025 Carolinas Resource Plan, App’x D – Load Forecast, Dkt. No. E-100, Sub 207, 10 (Oct. 1, 2025).

²³ See, generally, Supplemental Planning Analysis, Dkt. No. E-100, Sub 190 (Oct. 1, 2025) (We note that Duke Energy’s load forecast created as part of its 2023-24 Carbon Plan IRP was updated to assume greater loads than those used in the 2023 Spring Load Forecast, due to the inclusion of greater data center load.).

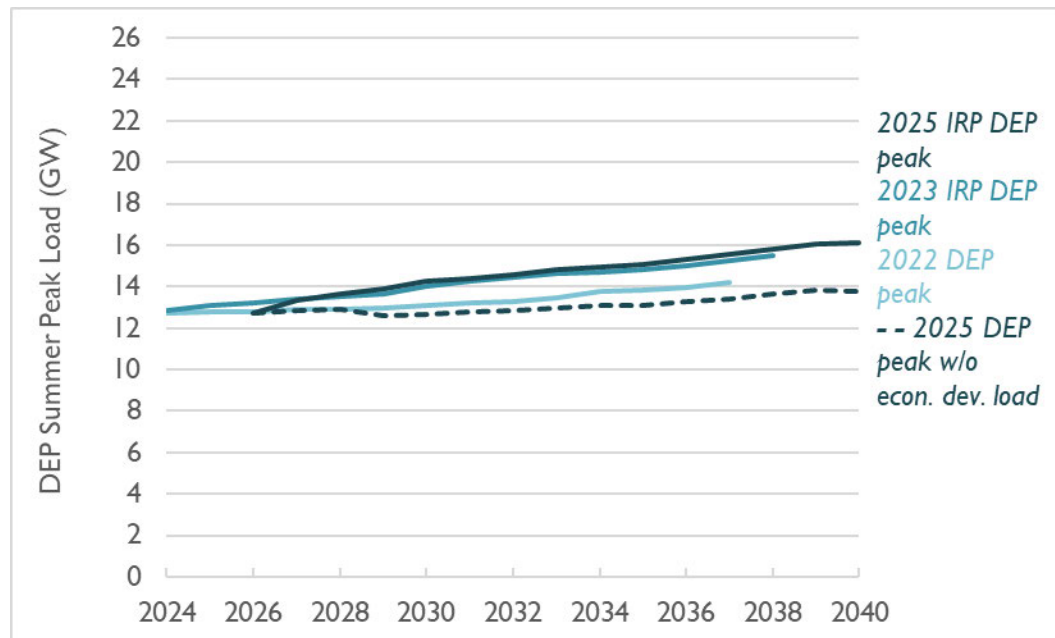
²⁴ See 2023 Carolinas Carbon Plan, App’x F – Electric Load Forecast, Dkt. No. E-100, Sub 179, 23 (May 16, 2022); see also 2022 Carolinas Resource Plan, App’x D – Electric Load Forecast, Dkt. No. E-100, Sub 190, 28–29 (Aug. 17, 2023).

Figure 1. Duke Energy's projection of load growth in DEC in 2022, 2023, and 2025 CPIRPs



Sources: 2025 DEC peak load from Duke Energy response to PSDR 6-13; 2023 DEC peak load from 2023 CPIRP – App'x D, at 28–29; 2022 DEC peak load from 2022 Carbon Plan – App'x F, at 23.

Figure 2. Duke Energy's projection of load growth in DEP in the 2022, 2023, and 2025 CPIRPs



Sources: 2025 DEP peak load from Duke Energy response to PSDR 6-13; 2023 DEP peak load from 2023 CPIRP – App'x D, at 28–29; 2022 DEP peak load from 2022 Carbon Plan – App'x F, at 23.

Table 2. Changes to load and peak demand in DEC and DEP²⁵

		DEC	DEP
2026-2040 compound annual growth rate	With economic development load	2.30%	1.70%
	Without economic development load	1.00%	0.60%
2030 peak load increases relative to without economic development load	GW increase	2.8	1.5
	% increase	15.10%	12.30%
2040 peak load increases relative to without economic development load	GW increase	4.5	2.3
	% increase	21.2	16.80%

Q HAS DUKE ENERGY'S NEW LARGE LOAD CHANGED ITS RETIREMENT PLANS FOR ITS EXISTING COAL ASSETS?

A Duke Energy states that since June 2024, the amount of planned large-load additions (load greater than 20 MW) to the DEC and DEP systems that are in the advanced stage of development has increased by 50 percent, which is approximately 2,000 MW on a full load projection basis. The Companies state that with anticipated load growth from economic development and the lead time required to develop new generating and transmission resources, it extended the "latest retirement dates" by two years for Cliffside 5, Marshall Unit 3, and Marshall Unit 4 under the Advancing Development Load Forecast (*see* Table 3 below). In DEC, retirement of Cliffside 5 (546 MW) is delayed by two years from 2031 to 2033; Marshall Unit 3 (658 MW) and Marshall Unit 4 (660 MW) are delayed by two years from 2032 to 2034; and Belews Creek Units 1 and 2 (1,110 MW each) are delayed by four years from 2036 to 2040. In DEP, the retirement of Roxboro

²⁵ See **Exhibit DG-3**, Duke Energy Corrected Response to PSDR 6-13.

Unit 2 (673 MW) is delayed by five years, from 2034 to 2039, while Roxboro Unit 4 (711 MW) is assumed to retire earlier in 2029 rather than 2034 as in the 2023 CPIRP.

Overall, Duke Energy delays the retirement of 8,019 MW of coal capacity by four years in the 2025 CPIRP, extending the fleet's retirement timeline to 2040 compared to 2036 in the 2023 CPIRP, mainly to support large customer load growth.

Table 3. Unit retirements from Duke Energy's 2023 CPIRP and 2025 CPIRP²⁶

	Winter capacity (MW)	2023 CPIRP	2025 CPIRP
DEC			
Marshall 1	380	2029	2029
Marshall 2	380	2029	2029
Cliffside 5	546	2031	<u>2033</u>
Marshall 3	658	2032	<u>2034</u>
Marshall 4	660	2032	<u>2034</u>
Belews Creek 1	1,110	2036	<u>2040</u>
Belews Creek 2	1,110	2036	<u>2040</u>
DEP			
Roxboro 1	380	2029	2029
Roxboro 2	673	2029	<u>2034</u>
Mayo 1	713	2031	2031
Roxboro 3	698	2034	2034
Roxboro 4	711	2034	<u>2029</u>

Note: Dates that are **bold and underlined** represent situations where a retirement date is changed in the 2025 CPIRP relative to the 2023 CPIRP.

²⁶ Compare 2023 Carolinas Resource Plan, App'x F – Coal Retirement Analysis, Dkt. No. E-100, Sub 190, 14 (Aug. 17, 2023) with 2025 Carolinas Resource Plan, App'x F, at 12.

1 **Q WHAT IMPACT DOES ADDITIONAL DATA CENTER LOAD HAVE ON**
 2 **THE PVRR OF DUKE ENERGY’S PORTFOLIOS?**

3 A Data centers have a large impact on PVRR. Overbuilding electric generating
 4 resources to accommodate uncertain future load can preclude a least-regrets future.
 5 The impact of data centers can be seen in the difference between PVRR calculated
 6 in the sensitivity scenario that uses Duke Energy’s Moderate Development Load
 7 forecast, and the PVRR calculated using the Preliminary Base Portfolio. The
 8 Preliminary Base scenario uses the Advancing Development load forecast, which
 9 contains an additional 2.0 GW of load by 2040 as compared to the Moderate
 10 Development load forecast, to approximate continued signings of data center load
 11 as a result of continued economic development. The additional 2.0 GW of load
 12 represents Mid-Stage Pipeline projects in the Carolinas, which are projects at early
 13 stages of negotiation. It includes prospective customers that have shown interest
 14 within the Companies’ territories, made site visits, and have initial LA negotiations
 15 underway. Mid-Stage Pipeline projects do not currently have executed ESAs or
 16 LAs and are not considered a Late-Stage Pipeline project, meaning this load is
 17 largely speculative.²⁷ The 2026–2040 PVRR of the Preliminary Base portfolio
 18 (which uses the larger Advancing Development load forecast) is \$8.4 billion, or 10
 19 percent, greater than the Moderate Development Load portfolio, highlighting the
 20 impact that even a 2.0 GW increase has on system costs.²⁸

²⁷ 2025 Carolinas Resource Plan, App’x D, at 10.

²⁸ See 2025 Carolinas Resource Plan, App’x D, at 79; see also Duke Energy Confidential Response to Public Staff DR 1-7 (referring to Confidential Attachment “PS DR 1-7 2025CPIRP_PVRR_Preliminary Base (Confidential).xlsx” and Confidential Attachment “PS DR 1-7 2025CPIRP_PVRR_Moderate Development Load (Confidential).xlsx”).

1 **Q WHAT ARE THE BILL IMPACTS OF INCLUDING THE ADDITIONAL**
 2 **2.0 GW OF LARGE LOAD?**

3 A Likewise, I can compare the bill impact of the Preliminary Base Portfolio (which
 4 includes an additional 2.0 GW of large load) with that of the Moderate
 5 Development Load portfolio (which does not include this 2.0 GW). In 2035, the
 6 Preliminary Base Portfolio results in a [BEGIN CONFIDENTIAL] [REDACTED]
 7 [END CONFIDENTIAL] in monthly residential bills as compared to the
 8 Moderate Development Load portfolio.²⁹

9 **C Concerns with Duke Energy’s modeling framework**

10 **Q DO YOU HAVE ANY CONCERNS WITH DUKE ENERGY’S MODELING**
 11 **FRAMEWORK?**

12 A Yes. I am concerned that the qualitative judgements Duke Energy made to craft the
 13 NTAP are not justified and that Duke selectively favors and relies on the results
 14 from specific sensitivities to justify different decisions in the NTAP. For example,
 15 Duke Energy discounts the different variations of low-load sensitivity scenarios in
 16 its selection of combined cycle resources for the NTAP as “an increasingly less
 17 likely outcome.”³⁰ Duke Energy does not consider all sensitivity portfolios equally
 18 likely to represent the future. Furthermore, Duke Energy does not adequately justify
 19 its reasoning for not relying on certain information (such as the decision to build
 20 combined cycle units) resulting from sensitivities with lower loads.³¹ I am also

²⁹ See Duke Energy Confidential Response to Public Staff DR 1-7 (referring to Confidential Attachment “CONFIDENTIAL_App C_Table C-47 & C-51_Bill Impacts - 1 Combined DEC and DEP.xlsx”).

³⁰ 2025 Carolinas Resource Plan, Ch. 3, at 20.

³¹ 2025 Carolinas Resource Plan, Ch. 2 – Methodology & Key Assumptions, Dkt. No. E-100, Sub 207, 20 (Oct. 1, 2025).

1 concerned that many costs were added to the revenue requirement outside of the
2 EnCompass modeling for the NTAP and Preliminary Base Portfolio. When costs
3 such as those for coal and nuclear resources are not represented in capacity
4 expansion and production cost models, they cannot be considered in the economic
5 selection of resource builds. It is possible that if these costs were incorporated into
6 EnCompass, the model would have determined a more economically efficient set
7 of resources to build and dispatch. Furthermore, I am concerned that Duke Energy's
8 investments in energy efficiency and DSM were not included in its NTAP as these
9 resources would likely lead to a lower PVRR. In particular, I note that Table C-42
10 in Duke Energy's CPIRP (reproduced below) shows that High EE (energy
11 efficiency) and High DSM sensitivities have marginally higher PVRRs through
12 2040: \$0.2 to \$0.5 billion, relative to a Preliminary Base PVRR of \$92.8B, or an
13 increase of 0.2 to 0.5 percent.³² The High EE and High DSM sensitivities have
14 lower PVRRs through 2050: -\$0.4 to -\$3.6 billion, relative to a Preliminary Base
15 PVRR of \$164.1 billion, or decreases of 0.2 to 2.2 percent.³³ These small
16 differences in PVRR relative to the Preliminary Base Portfolio indicate that if
17 energy efficiency and DSM resources were modeled together, and cost-optimized
18 alongside other resource changes, they may be able to produce ratepayer savings
19 through 2040.³⁴

³² 2025 Carolinas Resource Plan, App'x C, at 79–80.

³³ *Id.*

³⁴ 2025 Carolinas Resource Plan, App'x C, at 79–80.

Table C-42: Demand-Side Management Sensitivities - Present Value of Revenue Requirements through 2040 and 2050 Relative to Base (\$B)

	PVRR Through 2040			PVRR Through 2050		
	DEC	DEP	CAR	DEC	DEP	CAR
High EE	-\$0.3	\$0.5	\$0.2	-\$0.2	-\$3.5	-\$3.6
Low EE	\$0.2	\$0.9	\$1.1	\$2.0	\$0.8	\$2.8
High DSM	-\$2.6	\$3.1	\$0.5	-\$1.3	\$0.9	-\$0.4
Low DSM	-\$1.2	\$2.0	\$0.9	-\$0.5	\$0.9	\$0.4

1

2 **Q DO YOU HAVE ANY CONCERNS WITH DUKE ENERGY'S COAL**
3 **RETIREMENT ANALYSIS?**

4 **A** Yes. Once Duke Energy completed its initial coal retirement analysis in its
5 preliminary evaluation, coal retirement dates were locked into the EnCompass
6 capacity expansion model and not revisited. Because Duke Energy locked these
7 retirement dates in place, they cannot be optimized against all other inputs and
8 parameters. It is possible that if these dates were to be co-optimized alongside other
9 exogenous decisions modeled in the NTAP, the EnCompass model would have
10 identified it as more economically efficient to retire more coal power plants or retire
11 coal power plants at earlier dates.

12

13 Splitting the analysis into these two steps also makes it harder to update when
14 conditions change or input parameters need to be updated. Rather than just updating
15 an input or parameter in EnCompass and rerunning the model, Duke Energy must
16 update multiple pieces of interconnected analysis. While there might be near-term
17 justifications for temporarily relying on aging legacy units for capacity, the cost-
18 effectiveness of this strategy is sensitive to the cost of maintaining the assets.

19 Notwithstanding these concerns, I retained Duke Energy's coal plant retirement

1 assumptions in order to minimize the differences between Duke Energy's modeling
2 and my own modeling.

3 **Q DO YOU HAVE ANY CONCERNS WITH DUKE ENERGY'S**
4 **ASSUMPTIONS AROUND EMERGING TECHNOLOGY**
5 **AVAILABILITY?**

6 A Yes. Specifically, Duke Energy's representation of LLWRs and ELNG may not
7 accurately reflect the availability or cost of these resources, as discussed below.

8 **Q WHAT ARE YOUR CONCERNS WITH THE LLWRs THAT DUKE**
9 **ENERGY MODELS?**

10 A Duke Energy's deployment plans for LLWRs are ambitious. Duke Energy assumes
11 that LLWRs can first become operational in 2037, and that they are available at a
12 price of [BEGIN CONFIDENTIAL] [REDACTED] [END
13 CONFIDENTIAL]³⁵ Few LLWRs are commercially deployed and may not be
14 available on a 2037 timeline or at the cost that Duke Energy currently projects. For
15 example, there are currently only two active LLWRs in the United States today.
16 Both utilize the Westinghouse AP1000 technology, and both are located at Plant
17 Vogtle in Georgia. These two LLWRs were completed seven years late and \$17
18 billion over budget.³⁶ Georgia Power estimates that the total cost of the two-reactor,

³⁵ See Duke Energy Confidential Response to PS DR 1-7 (referring to Confidential Attachment "PS DR 1-7 IRP Generic Unit Summary DEC DEP (Confidential).xlsx").

³⁶ Jeff Amy, *Georgia Nuclear Rebirth Arrives 7 years late, \$17B Over Cost*, ASSOC. PRESS (May 25, 2023), <https://apnews.com/article/georgia-nuclear-power-plant-vogtle-rates-costs-75c7a413cda3935dd551be9115e88a64>.

1 2,430-MW project is \$34 billion, or roughly \$14,000 per kW in 2024 dollars.³⁷ This
 2 is [BEGIN CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL] more
 3 expensive than the cost assumed by Duke Energy for its modeled LLWR resources.
 4 A third LLWR began construction at the VC Summer nuclear plant in 2013, but
 5 was later cancelled by Santee Cooper in 2017 due to reasons such as, “rising costs,
 6 decreasing electricity demand, construction delays, and the bankruptcy of
 7 Westinghouse.”³⁸ In 2025, Westinghouse released a study touting the economic
 8 benefits of restarting construction at VC Summer Unit 3.³⁹ This study assumes that
 9 VC Summer Unit 3 would take seven years to construct, at a unit that had already
 10 been under construction for four years before cancellation. This long lead time
 11 suggests that nuclear generating resources are not an ideal option for meeting new,
 12 near-term load increases. A 2023 analysis by EPRI comparing nth-of-a-kind versus
 13 first-of-a-kind costs notes that “[t]he rising capital costs for [LLWRs] make up at
 14 least 60% of their levelized cost of electricity, making them less competitive
 15 relative to alternative resources.”⁴⁰ Duke Energy’s assumptions for the per-kW
 16 price and timeline of LLWRs are unrealistic and pose risks for consumers.

³⁷ Slade Johnson, *Plant Vogtle Unit 4 Begins Commercial Operation*, U.S. ENERGY INFO. ADMIN. (May 1, 2024), <https://www.eia.gov/todayinenergy/detail.php?id=61963>; Darrell Proctor, *Vogtle Nuclear Expansion Price Tag Tops \$30 Billion*, POWER MAGAZINE (May 9, 2022), <https://www.powermag.com/vogtle-nuclear-expansion-price-tag-tops-30-billion/>.

³⁸ Michael Mobilia, *South Carolina Utilities Stop Construction of New Nuclear Reactors*, U.S. ENERGY INFO. ADMIN. (Aug. 14, 2017), <https://www.eia.gov/todayinenergy/detail.php?id=32472#>.

³⁹ *The Economic Impact of a Two-Unit Westinghouse AP1000 Project at V.C. Summer*, PRICEWATERHOUSECOOPERS LLP (PwC) (Nov. 2025), <https://info.westinghousenuclear.com/hubfs/News%20and%20Press%20Releases/The%20Economic%20Impact%20of%20a%20Two-Unit%20V.C%20Summer%20AP1000%20Deployment%20FINAL.pdf>.

⁴⁰ J. Shook, et al., *Program on Technology Innovation: A Comparison of Capital Costs Between Large Light Water Reactors and Small Modular Reactors: Considering the Impact of Financing Costs*, EPRI, 1 (Aug. 2023), <https://restservice.epri.com/publicdownload/000000003002026582/0/Product>.

1

2 I also note that small modular reactors (SMRs) are an equally risky technology.
 3 Duke Energy discusses the value of a so-called “second-mover strategy” and
 4 assumes other electric utilities around the country assume the risk of first-of-a-kind
 5 technology deployment represented by SMRs.⁴¹ Duke Energy assumes that SMRs
 6 could have a price of [BEGIN CONFIDENTIAL] [REDACTED] [END
 7 CONFIDENTIAL] making them [BEGIN CONFIDENTIAL] [REDACTED]
 8 [REDACTED] [END CONFIDENTIAL] than their assumptions for LLWRs, which
 9 itself is likely an under-estimate.⁴² No SMRs are in commercial operation at the
 10 time of this writing. As a result, SMRs are not a viable alternative to existing
 11 resources and conventional technology, with proven resource types like energy
 12 efficiency, demand response, and pumped storage being more competitive
 13 alternatives to help reduce and serve demand.

14 **Q WHAT IS ENHANCED LIQUIFIED NATURAL GAS AND WHAT**
 15 **ASSUMPTIONS DOES DUKE ENERGY MAKE?**

16 **A** A second emerging resource included by Duke Energy is ELNG as an alternative
 17 to firm pipeline capacity. ELNG is a novel technology that involves the siting of
 18 liquefaction, storage, and vaporization facilities alongside a gas-fired power plant.
 19 Pipeline gas is converted to LNG onsite during periods of low prices via
 20 liquefaction, stored on site, and then vaporized and consumed in the nearby power
 21 plant during “either a multiday winter polar vortex or for a few hours on a hot

⁴¹ 2025 Carolinas Resource Plan, App’x J – Nuclear, Dkt. No. E-100, Sub 207, 25–26 (Oct. 1, 2025).

⁴² See Duke Energy Confidential Response to Public Staff DR 1-7 (referring to Confidential Attachment “PS DR 1-7 IRP Generic Unit Summary DEC DEP (Confidential).xlsx”).

1 summer evening.”⁴³ Duke assumes that all gas resources modeled in [BEGIN
 2 CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL] include the costs of
 3 either firm gas contracts or ELNG facilities.⁴⁴ Duke assumes that the upfront cost
 4 of an ELNG facility is [BEGIN CONFIDENTIAL] [REDACTED] [END
 5 CONFIDENTIAL]⁴⁵

6 **Q WHAT ARE YOUR CONCERNS WITH DUKE ENERGY’S ELNG**
 7 **ASSUMPTIONS?**

8 A Based on Duke Energy’s estimated cost of a new combined cycle gas plant of
 9 [BEGIN CONFIDENTIAL] [REDACTED] [REDACTED] [REDACTED] [REDACTED] [END
 10 CONFIDENTIAL] this inclusion of the ELNG technology represents a cost
 11 increase of [BEGIN CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL] for
 12 any combined cycle using this technology.⁴⁶ Duke Energy states that “only the fixed
 13 cost associated with ELNG for new gas resources was assumed in the capacity
 14 expansion without capturing the added operational impacts of ELNG to the
 15 system.”⁴⁷ These operational costs are later included during a production cost step,
 16 but because this step involves the estimation of least cost dispatch assuming that
 17 certain power plants are constructed, these operational costs are not accounted for
 18 in the determination of whether an ELNG-supported gas plant is the most cost-

⁴³ 2025 Carolinas Resource Plan, App’x I, at 5.

⁴⁴ See Duke Energy Confidential Response to Public Staff 10-3(b).

⁴⁵ See Duke Energy Confidential Response to Public Staff DR 16-1(e) (referring to the data within Confidential attachment “CONFIDENTIAL PSDR 16-1-e Duke Energy LNG Generic - Base Case.xlsx,” at tab “ELNG Base Case!H12”).

⁴⁶ See Duke Energy Confidential Response to Public Staff DR 1-7 (referring to Confidential Attachment “PS DR 1-7 IRP Generic Unit Summary DEC DEP (Confidential).xlsx,” at tab “2025 IRP Summary_IRP!AB10”).

⁴⁷ 2025 Carolinas Resource Plan, App’x C, at 43.

1 effective resource to build. Duke Energy stated that its cost assumptions for ELNG
2 are developed based on comparable “equipment and facilities [that are] required to
3 exist and not be first-of-a-kind. The intent was to have LNG components of a
4 similar type and scale that had previously been constructed and in operation.”⁴⁸ But
5 while several similar facilities have been proposed around the country, none have
6 been built.⁴⁹

7
8 Because there is limited firm pipeline capacity in the region, Duke Energy is relying
9 on ELNG as an (expensive) silver bullet to ensure a firm fuel supply and to manage
10 fuel price volatility. But because ELNG is not a mature, well-established
11 technology—with uncertain costs and availability—fuel price volatility risks and
12 costs are likely to be understated in Duke Energy’s modeling. The assumption that
13 ELNG resources can be built at scale, at Duke Energy’s assumed price point, and
14 on Duke Energy’s assumed timeline allowed Duke Energy to develop a
15 Recommended Portfolio that relies heavily on gas resources. But if any of Duke
16 Energy’s assumptions are wrong, the associated risks and increased costs will fall
17 squarely on ratepayers.

⁴⁸ 2025 Carolinas Resource Plan, App’x I, at 7.

⁴⁹ Robert Zullo, *Utilities Plan Onsite Gas Storage to Improve Reliability; Critics Warn of Costs, Safety Concerns*, LOUISIANA ILLUMINATOR (Jan. 17, 2024), <https://lailluminator.com/2024/01/17/gas-safety/>.

IV NCSEA ALTERNATIVE MODELING

1
2 **Q PLEASE DESCRIBE THE MODELING EXERCISE THAT YOU**
3 **COMPLETED RELATING TO DUKE ENERGY’S 2025 CPIRP.**

4 A I completed independent modeling of Duke Energy’s Preliminary Base and NTAP
5 scenarios using Duke Energy’s EnCompass database (referred to as the
6 “Reproduced Base” and “Reproduced NTAP” scenarios). I then modeled an
7 NCSEA Alternative scenario that illustrates potential methods for Duke Energy to
8 reduce costs, emissions, and reliability risks to its ratepayers. I also modeled a
9 combined utility sensitivity (the “NCSEA Combined Utility”) that incorporates
10 Duke Energy’s assumptions in its combined utility sensitivity into the input
11 parameters for the NCSEA Alternative scenario. My analysis is based on a “least-
12 regrets” framework of identifying the resources that best meet capacity needs at the
13 lowest cost, without overcommitting Duke Energy to capital investments that may
14 ultimately be unnecessary.

A NCSEA modeling methodology

15
16 **Q PLEASE SUMMARIZE THE MODELING TOOLS AND**
17 **METHODOLOGIES ON WHICH YOU RELY.**

18 A I use the EnCompass capacity optimization and dispatch model to simulate resource
19 choices and impacts in the DEC and DEP service territories. EnCompass is the
20 same capacity expansion and production cost model used by Duke Energy.
21 EnCompass was developed by Anchor Power Solutions (now Yes Energy) and
22 covers all facets of power system planning, including:

- 1 • short-term scheduling, including detailed unit commitment and economic
- 2 dispatch, with modeling of load-shaping and -shifting capabilities;
- 3 • mid-term energy budgeting analysis, including maintenance scheduling and
- 4 risk analysis;
- 5 • long-term integrated resource planning, including capital project optimization,
- 6 economic generating unit requirements, and environmental compliance; and
- 7 • market price forecasting for energy, ancillary services, capacity, and
- 8 environmental programs.

9 I calculate a revenue requirement and PVRR for the NCSEA Alternative Portfolio
10 based on Duke Energy's revenue requirement model.⁵⁰ I then use the revenue
11 requirement to calculate bill impacts for the residential customer class. This same
12 operation is then performed for the NCSEA Combined Utility Portfolio.

13
14 I also use the SERVVM reliability model to evaluate the reliability of the NCSEA
15 Alternative Portfolio. Duke Energy also utilized SERVVM to test the reliability of
16 some of its portfolios. SERVVM is a widely used reliability planning and production
17 cost model. SERVVM evaluates an electric system through the lens of uncertainty
18 and risk by combining information about past risks—including historical weather,
19 economic forecast error, load uncertainty, unit performance, and other
20 information—and performing thousands of simulations to evaluate the likelihood,
21 magnitude, and economic cost of future reliability events.

⁵⁰ See Duke Energy Confidential Response to Public Staff DR 1-7 (referring to Confidential Attachment "2025CPIRP_PVRR_Recommended (Confidential).xlsx").

1
2 For each weather year, SERVVM uses historical weather patterns to develop load
3 profiles in order to estimate how loads would respond if the weather experienced
4 in that particular year were to repeat. These weather years also reflect the changing
5 profiles of renewable resources. SERVVM models the uncertainty around generator
6 unit availability through the simulation of random unit outage draws. This
7 information is combined to produce metrics related to the frequency of loss-of-load
8 events, event duration, and event magnitude.

9 **B The “Reproduced Base” Portfolio and “Reproduced NTAP”**

10 **Q ABOVE, YOU REFER TO THE “REPRODUCED BASE” AND**
11 **“REPRODUCED NTAP.” HOW DO THOSE PORTFOLIOS DIFFER**
12 **FROM DUKE ENERGY’S PRELIMINARY BASE SCENARIO, NTAP**
13 **SCENARIO, PRELIMINARY BASE PORTFOLIO, AND RECOMMENDED**
14 **PORTFOLIO?**

15 **A** EnCompass will take all inputs and parameters and produce a cost-minimized mix
16 of capacity additions and retirements. During production cost modeling, the model
17 will determine a cost-minimized dispatch for each of the resources selected in the
18 capacity expansion model. To ensure valid and comparable scenario modeling and
19 allow model runs to complete on Synapse’s local modeling infrastructure, I reduce
20 the memory usage of the model by modifying EnCompass’ Mix Integer
21 Programming (“MIP”) stop basis. A higher MIP stop basis reduces the precision of
22 the model, in exchange for lower memory usage and shorter model runtimes (with
23 the reverse being true for lower MIP stop bases). All things being equal, a lower

1 MIP stop basis will produce more precise results at a cost of longer modeling runs.
2 I use a higher MIP stop basis than Duke in order to allow model runs to complete
3 on my organization's modeling computing infrastructure. Duke uses a 50 MIP stop
4 basis for each of its scenarios, while I use a 90 MIP stop basis. This decision—
5 which allows for runs to complete—has a minimal impact on the results. The
6 “Reproduced Base” scenario and “Reproduced NTAP” scenario are the names I
7 give the EnCompass runs that use Duke Energy's assumptions and model
8 parameters but have slight deviations because of the MIP stop basis adjustments.
9 Below, I further describe “Reproduced Base Portfolio” and a “Reproduced
10 Recommended Portfolio;” these are the resource outputs and associated costs of the
11 “Reproduced Base” and “Reproduced NTAP” scenarios, respectively.

12 **Q PLEASE DESCRIBE HOW COMPARABLE YOUR REPRODUCED BASE**
13 **PORTFOLIO IS TO DUKE ENERGY'S MODELING.**

14 A When I assess the results of the Reproduced Base Portfolio (developed using a 90
15 MIP stop basis), as compared to the results of Duke Energy's Preliminary Base
16 Portfolio (developed using a 50 MIP stop basis), I observe differences of -0.5 to 1.4
17 percent in net annual capacity additions between 2026–2040. The PVRR associated
18 with the Reproduced Base Portfolio is 0.18 percent lower than the PVRR of Duke
19 Energy's Preliminary Base Portfolio. Table 4 and Table 5 show the net capacity
20 additions for Duke Energy's Preliminary Base Portfolio and the Reproduced Base
21 Portfolio from 2026 to 2035 and from 2026 to 2040 respectively.

Table 4. Capacity changes (MW) by 2035 in Duke Energy's Preliminary Base Portfolio and Reproduced Base Portfolio

Resource type	Duke Preliminary Base portfolio (developed with a MIP stop basis of 50)	Reproduced Base Portfolio (developed with a MIP stop basis of 90)	Delta (<i>Reproduced Base Portfolio - Duke Energy's Preliminary Base Portfolio</i>)
Coal	-5,769	-5,769	-
Demand response	427	427	-
Other	-55	-55	-
Natural Gas CC	7,004	7,004	-
Natural Gas CT	3,039	3,039	-
Natural Gas IC	-167	-167	-
Hydro	32	32	-
Pumped Storage	120	120	-
Nuclear	251	251	-
Solar	6,282	8,157	1,875
Wind	-	-	-
Battery Storage	6,116	6,216	100
Total	17,281	19,256	1,975

Table 5. Capacity changes (MW) by 2040 in Duke Energy's Preliminary Base Portfolio and Reproduced Base Portfolio

Resource type	Duke Preliminary Base portfolio (MIP stop basis of 50)	Reproduced Base Portfolio (MIP stop basis of 90)	Delta (<i>Reproduced Base Portfolio - Duke Energy's Preliminary Base Portfolio</i>)
Coal	-8,049	-8,049	-
Demand response	554	554	-
Other	-55	-55	-
Natural Gas CC	8,369	8,369	-
Natural Gas CT	3,866	3,866	-
Natural Gas IC	-178	-178	-
Hydro	32	32	-
Pumped Storage	120	120	-
Nuclear	3,602	3,602	-
Solar	12,037	13,912	1,875
Wind	-	-	-
Battery Storage	8,616	8,616	-
Total	28,915	30,790	1,875

Q PLEASE DESCRIBE HOW COMPARABLE YOUR REPRODUCED RECOMMENDED PORTFOLIO IS TO DUKE ENERGY'S MODELING.

A When I assess the results of the Reproduced Recommended Portfolio (developed using a 90 MIP stop basis), as compared to the results of Duke Energy's

Recommended Portfolio (developed using a 50 MIP stop basis), I observe differences of -0.3 to 0 percent in net annual capacity additions between 2026–2040. The PVRR associated with the Reproduced Recommended Portfolio is 0.2 percent lower than the PVRR of Duke Energy’s Recommended Portfolio. Table 6 and Table 7 show the net capacity additions from 2026 to 2035 and 2026 to 2040, respectively, in the Reproduced Recommended Portfolio as compared to Duke Energy’s Recommended Portfolio. There are no capacity differences in 2035 and capacity differences of only 0.4 percent in 2040.

Table 6. Capacity changes (MW) by 2035 in Duke Energy’s Recommended Portfolio and Reproduced Recommended Portfolio

Resource type	Duke Energy’s Recommended Portfolio (developed with a MIP stop basis of 50)	Reproduced Recommended Portfolio (developed with a MIP stop basis of 90)	Delta (<i>Reproduced Recommended Portfolio - Duke Energy’s Recommended Portfolio</i>)
Coal	-5,769	-5,769	-
Demand response	427	427	-
Other	-55	-55	-
Natural Gas CC	7,004	7,004	-
Natural Gas CT	3,039	3,039	-
Natural Gas IC	-167	-167	-
Hydro	32	32	-
Pumped Storage	120	120	-
Nuclear	251	251	-
Solar	8,607	8,607	-
Wind	-	-	-
Battery Storage	6,516	6,516	-
Total	20,006	20,006	-

Table 7. Capacity changes (MW) by 2040 in Duke Energy's Recommended Portfolio and Reproduced Recommended Portfolio

Resource type	Duke Energy's Recommended Portfolio (developed with a MIP stop basis of 50)	Reproduced Recommended Portfolio (developed with a MIP stop basis of 90)	Delta (<i>Reproduced Recommended Portfolio - Duke Energy's Recommended Portfolio</i>)
Coal	-8,049	-8,049	-
Demand response	554	554	-
Other	-55	-55	-
Natural Gas CC	8,369	8,369	-
Natural Gas CT	3,438	3,438	-
Natural Gas IC	-178	-178	-
Hydro	32	32	-
Pumped Storage	120	120	-
Nuclear	3,602	3,602	-
Solar	14,212	13,987	-225
Wind	0	0	-
Battery Storage	9,416	9,516	100
Total	31,462	31,337	-125

C NCSEA's Alternative scenario inputs and assumptions, modeling parameters, and results

Q DESCRIBE THE INPUTS AND ASSUMPTIONS TO THE NCSEA ALTERNATIVE SCENARIO.

A I designed the NCSEA Alternative scenario primarily using the scenario parameters specified in the Reproduced Base scenario. To ensure my results are comparable to Duke Energy's results, I maintain as many of Duke Energy's inputs, assumptions, and model parameters as possible. In doing so, I did not independently evaluate each of the inputs and assumptions used by Duke Energy. Rather, I opted to focus on and modify only a selection of the Companies' inputs and assumptions to isolate their impacts and ensure my results were comparable. Accordingly, I only made four major changes to Duke Energy's inputs, assumptions, and model parameters:

- First, the NCSEA Alternative scenario incorporates modified load in line with Duke Energy's High EE sensitivity.

- Second, the NCSEA Alternative scenario incorporates additional DSM resources in line with Duke Energy's High DSM sensitivity.
- Third, the NCSEA Alternative scenario assumes that Bad Creek II is online in 2037, while maintaining all other attributes of this resource from Duke Energy's Preliminary Base scenario.
- Fourth, the NCSEA Alternative scenario allows the EnCompass model to select PowerPair resources in line with the datasets specified in Duke Energy's PowerPair sensitivity.

All datasets used to modify inputs to the Reproduced Base were developed using datasets created by Duke Energy. I maintain all other inputs and EnCompass modeling settings as Duke Energy. Table 8 shows the sources I relied on for my modeling.

Table 8. EnCompass modeling input sources used in the NCSEA Alternative scenario

Update	Duke Energy EnCompass Input Dataset
More energy efficiency	High EE
More demand response	High DSM
PowerPair program	PowerPair Storage
Bad Creek II	Bad Creek II Forced 2040*

**This dataset was modified to force the Bad Creek II resource online in 2037.*

Q EXPLAIN HOW YOU MODELED ENERGY EFFICIENCY AND DSM IN THE NCSEA ALTERNATIVE SCENARIO.

A I use Duke Energy's "High EE" and "High DSM" datasets from its respective sensitivity analysis. The "High EE" dataset contains an energy efficiency load forecast that avoids 1.5 percent of eligible retail sales by 2040. This is 0.5 percent more energy efficiency than the forecast Duke Energy modeled in the Advancing Development load, which had 1 percent of eligible retail sales. The "High DSM"

1 dataset increases the maximum available capacity of DSM resources assumed by
2 Duke Energy in its CPIRP. I make no changes to either dataset.

3 **Q WHY DID YOU MAKE THE CHANGES REGARDING ENERGY**
4 **EFFICIENCY AND DSM AS DESCRIBED IN THE NCSEA**
5 **ALTERNATIVE SCENARIO?**

6 A I include additional energy efficiency and DSM resources because energy
7 efficiency is generally the lowest-cost resource available, and I hypothesized that
8 as long as there is still cost-effective energy efficiency and DSM available,
9 incremental deployment of these resources could lead to a lower PVRR. In
10 particular, I note that Table C-42 in Duke Energy's application materials show that
11 High EE and High DSM sensitivities have marginally higher PVRRs through 2040:
12 \$0.2 to \$0.5 billion, relative to a Preliminary Base PVRR of \$92.8 billion, or an
13 increase of 0.2 to 0.5 percent.⁵¹ The High EE and High DSM sensitivities have
14 lower PVRRs through 2050: -\$0.4 to -\$3.6 billion, relative to a Preliminary Base
15 PVRR of \$164.1 billion, or decreases of 0.2 to 2.2 percent.⁵² This indicates that if
16 the resources modeled in each of these sensitivities were modeled together and cost-
17 optimized alongside other resource changes, they could produce ratepayer savings
18 even through 2040.

⁵¹ 2025 Carolinas Resource Plan, App'x C, at 79–80.

⁵² *Id.*

1 **Q EXPLAIN HOW YOU MODELED BAD CREEK II IN THE NCSEA**
 2 **ALTERNATIVE SCENARIO.**

3 A I use Duke Energy’s “Bad Creek II Forced 2040” dataset from its respective
 4 sensitivity analysis. However, instead of assuming Bad Creek II comes online in
 5 2040, I assume that Bad Creek II has a commercial operating year of 2037. In Duke
 6 Energy’s 2023 Carolinas Resource Plan, the Companies modeled Bad Creek II in
 7 service at the beginning of 2034.⁵³ With delays since the 2023 CPIRP, I assumed
 8 an additional lead time for the resource with a 2037 in-service date in the NCSEA
 9 Alternative scenario.

10 **Q WHY DID YOU MAKE THE CHANGES REGARDING BAD CREEK II AS**
 11 **DESCRIBED IN THE NCSEA ALTERNATIVE SCENARIO?**

12 A I include the Bad Creek II resource as it represents a mature long-duration storage
 13 resource that provides operational flexibility and provides ancillary services that
 14 help maintain a balanced and reliable system.⁵⁴ As Duke Energy also notes, there
 15 are low risks associated with Bad Creek II because it is a mature technology, its
 16 construction would not rely on overseas materials, and it would be located next to
 17 the existing Bad Creek facility “where the geology is known from prior
 18 construction and the project is very similar to the current Bad Creek facility.”⁵⁵

⁵³ See 2023 Carolinas Resource Plan, Ch. 3 – Portfolios, Dkt. No. E-100, Sub 190, 3 (Aug. 17, 2023) (“Note 7: Bad Creek II Pumped Storage Hydro is projected to come into service by mid-2033; for planning purposes, the modeling reflects this resource coming into all portfolios beginning of year 2034.”); see also 2023 Carolinas Resource Plan, Supplemental Planning Analysis, Dkt. No. E-100, Sub 190, 8–9 (Jan. 31, 2024) (same).

⁵⁴ 2025 Carolinas Resource Plan, App’x H – Renewables & Energy Storage, Dkt. No. E-100, Sub 207, 15 (Oct. 1, 2025).

⁵⁵ *Id.*, at 17.

1 Furthermore, this resource was assumed to be online in 2034 in Duke Energy's
 2 Recommended Portfolio in its 2023 CPIRP modeling.⁵⁶ During 2025, Duke Energy
 3 decided to withdraw Bad Creek II from the 2022 DISIS cluster study for strategic
 4 purposes, but unreasonably deferred Bad Creek II's ability to be selected in its
 5 modeling in the current proceeding.⁵⁷ I have assumed that this resource comes
 6 online three years later to account for the time elapsed since the 2023 CPIRP.

7 **Q EXPLAIN HOW YOU MODELED THE POWERPAIR PROGRAM IN THE**
 8 **NCSEA ALTERNATIVE SCENARIO.**

9 A I use Duke Energy's "PowerPair Storage" dataset from its "PowerPair Selectable"
 10 scenario. I make no changes to this dataset.

11 **Q WHY DID YOU MAKE THE CHANGES REGARDING THE POWERPAIR**
 12 **PROGRAM AS DESCRIBED IN THE NCSEA ALTERNATIVE**
 13 **SCENARIO?**

14 A Duke Energy modeled an extension of the PowerPair program because it represents
 15 an opportunity for ratepayers to "combine the savings of solar power with the
 16 reliability and security of backup battery storage."⁵⁸ As a result, this program
 17 expansion leads to additional community-owned power resources that could have

⁵⁶ 2023 Carolinas Resource Plan, Ch. 3, at 3; see also 2023 Carolinas Resource Plan, Supp. Planning Analysis, at 8–9.

⁵⁷ 2025 Carolinas Resource Plan, App'x H, at 16; see also Order Accepting Stipulation, Granting Partial Waiver of Commission Rule R8-60a(D)(4), and Providing Further Direction for Future Planning, Dkt. No. E-100, Sub 190, 178 (Nov. 1, 2024) ("Duke shall pursue all reasonable development activities to construct 1,834 MW of PSH at the Bad Creek II facility to be placed into service by 2034, and provide annual updates on the progress of construction of Bad Creek II beginning with the next CPIRP . . . Duke shall provide an explanation in the next CPIRP if Bad Creek II cannot be completed by 2034 . . .") [hereinafter, "2023-2024 CPIRP Order"].

⁵⁸ 2025 Carolinas Resource Plan, Ch. 2, at 15.

cost and reliability benefits for participants.⁵⁹ However, Duke Energy only modeled PowerPair as a selectable resource in an “informational portfolio” and does not include it as a selectable or exogenous resource in the Preliminary Base scenario or the Near Term Action Plan.⁶⁰ PowerPair represents a resource option that can be scaled up and accelerated in the planning horizon due to it being a community-owned, distributed asset.

Q DOES THE NCSEA ALTERNATIVE SCENARIO INCORPORATE ANY OTHER EXOGENOUS RESOURCE INPUTS AND ASSUMPTIONS THAT ARE DIFFERENT THAN THOSE USED BY DUKE ENERGY IN ITS PRELIMINARY BASE SCENARIO?

A No, I made no other changes to input assumptions or datasets.⁶¹

Q WITH THESE CHANGED INPUTS AND ASSUMPTIONS, WHAT ARE THE ANNUAL CAPACITY ADDITIONS BY RESOURCE TYPE IN THE NCSEA ALTERNATIVE PORTFOLIO?

A In Table 9, I show the annual capacity additions by resource type in the NCSEA Alternative Portfolio. In the NCSEA Alternative Portfolio, through 2040, the model builds 13.8 GW of solar, 8.1 GW of battery storage, 3.9 GW of natural gas combustion turbines, 7.0 GW of natural gas combined cycle plants, and 2.5 GW of

⁵⁹ See, *2025 Carolinas Resource Plan*, App’x C, at 64 (Duke Energy states the “base forecast for PowerPair DR projects approximately 1,000 households are enrolled annual through 2029, and then approximately 500 households are assumed to enroll annually from 2030-2050.” This claim is inconsistent with the EnCompass outputs of Duke Energy’s Preliminary Base Portfolio which do not appear to include any future incremental growth in PowerPair resources.

⁶⁰ *Id.*, at 63–64.

⁶¹ Note, my analysis did not include an examination as to the reasonableness of Duke Energy’s assumed cost parameters and does not include any changes to these parameters.

1 nuclear generation capacity. The NCSEA Alternative Portfolio also builds Bad
2 Creek II in 2037 with 1.8 GW capacity and the portfolio includes 630 MW of
3 additional demand response. The model builds no wind resources in this scenario.⁶²
4

⁶² Note that these findings do not shift NCSEA’s position on the forward-going viability of onshore and offshore wind, nor do they reflect changes to NCSEA’s concerns with respect to the application of the offshore wind acquisition request for information (“ARFI”). As stated in footnote 61, above, my analysis did not include an examination as to the reasonableness of Duke Energy’s assumed cost parameters and does not include any changes to these parameters. Changes to these parameters (for example, lower forward-going capital costs) could yield different modeling results.

1 **Table 9. Annual capacity additions (MW) by resource type, NCSEA Alternative Portfolio**

Year	Coal	Solar	Battery Storage	Demand response	PowerPair	Natural Gas CT	Natural Gas CC	Nuclear	Wind	Pumped Storage
2026	-	442	203	124	0	116	55	-	-	-
2027	-	969	143	56	1	44	92	-	-	-
2028	30	631	654	51	1	56	33	13	-	-
2029	-1,851	1,322	1,223	46	3	861	1,365	88	-	-
2030	-	1,184	348	32	0	855	1,365	75	-	60
2031	-713	1,226	94	30	0	255	1,365	75	-	60
2032	-	98	51	31	0	-4	-	-	-	-
2033	-546	122	1,000	30	5	-	1,365	-	-	-
2034	-2,689	859	1,000	28	5	428	1,365	-	-	-
2035	-	1,154	1,000	30	5	-	-	-	-	-
2036	-	1,153	1,000	27	5	-	-	-	-	-
2037	-	1,154	1,000	28	3	-	-	-	-	1,760
2038	-	1,155	400	27	3	-	-	1,117	-	-
2039	-	1,155	-	27	3	-	-	-	-	-
2040	-2,280	1,138	-	28	3	1,255	-	1,117	-	-
Total	-8,049	13,762	8,116	592	38	3,866	7,004	2,485	-	1,880

2

1 **Q WITH THESE CHANGED INPUTS AND ASSUMPTIONS, HOW DO THE**
2 **ANNUAL CAPACITY ADDITIONS BY RESOURCE COMPARE**
3 **BETWEEN THE REPRODUCED RECOMMENDED PORTFOLIO AND**
4 **THE NCSEA ALTERNATIVE PORTFOLIO?**

5 A Table 10 compares the resource additions between the Reproduced Recommended
6 Portfolio and the NCSEA Alternative Portfolio. In addition to exogenous resources
7 in the NCSEA Alternative Portfolio—including additional pumped storage, energy
8 efficiency, demand response, and PowerPair resources—the NCSEA Alternative
9 Portfolio has the following changes in resource builds, resulting from least cost
10 optimization:

- 11 • An additional 428 MW of natural gas combustion turbine is selected by 2040.
- 12 • The NCSEA Alternative avoids 1,117 MW of nuclear capacity that the
13 Reproduced Recommended Portfolio includes in 2037.
- 14 • The NCSEA Alternative Portfolio also defers 1,365 MW of natural gas
15 combined cycle units that the Reproduced Recommended Portfolio includes in
16 2032. This resource is deferred from 2032 to 2034, implying that this resource
17 is not needed for the NTAP. The NCSEA Alternative Portfolio also avoids the
18 addition of another 1,365 MW of combined cycle capacity in 2040. This implies
19 that the need for this resource can be revisited in future CPIRP analyses.
- 20 • The NCSEA Alternative Portfolio also selects less utility-scale solar, however
21 that decrease is mostly offset by the addition of 156 MW of distributed
22 resources including demand response and PowerPair.

- The NCSEA Alternative Portfolio selects 1,400 fewer megawatts of battery storage than the Reproduced Recommended Portfolio.

I did not make any other changes to exogenous resources assumed by Duke Energy.

Table 10. Comparison of total capacity in the NCSEA modeled portfolios, 2040 (MW)

Resource type	Reproduced Recommended Portfolio	NCSEA Alternative Portfolio	Delta (NCSEA Alternative less Reproduced Recommended)
Coal	849	849	-
Demand response	2,416	2,572	156
PowerPair	-	38	38
Other	74	74	-
Natural Gas CC	14,293	12,928	-1,365
Natural Gas CT	10,083	10,511	428
Natural Gas IC	187	187	-
Hydro	1,398	1,398	-
Pumped Storage	2,540	4,300	1,760
Nuclear	14,785	13,668	-1,117
Solar	19,051	18,826	-225
Wind	-	-	-
Storage	9,608	8,208	-1,400
Total	75,284	73,558	-1,725

Note: The NCSEA Alternative Portfolio is built in response to lower load than is modeled in either the Duke Energy Recommended Portfolio or the Reproduced Recommended Portfolio. By 2040, the NCSEA Alternative Portfolio load is reduced as a result of an additional 3,605 GWh in energy efficiency savings.

Q HOW WOULD YOU DESCRIBE THE ANNUAL CAPACITY ADDITIONS BY RESOURCE IN THE NCSEA ALTERNATIVE PORTFOLIO?

A Overall, the NCSEA Alternative Portfolio offers a “least-regrets” portfolio. As I discuss below, the NCSEA Alternative Portfolio is a lower cost to ratepayers compared to the Reproduced Recommended Portfolio, while maintaining operational flexibility. By deferring natural gas capacity in 2032, the NCSEA Alternative Portfolio ensures that Duke Energy does not commit to significant capital expenditures to build additional capacity in the face of significant

1 uncertainty. The NCSEA Alternative Portfolio is a “least-regrets” portfolio because
 2 it demonstrates that certain new capacity additions, with long-lived useful lives, do
 3 not have to be approved for planning purposes in this CPIRP; this portfolio avoids
 4 establishing a path to commit customers to a more expensive future.

5 **Q WHAT ALLOWS THE NATURAL GAS CAPACITY TO BE DEFERRED**
 6 **IN 2032?**

7 A The NCSEA Alternative Portfolio contains greater energy efficiency savings, and
 8 thus lower load. By 2040, load is 1.5 percent lower in the NCSEA Alternative
 9 Portfolio than in the Recommended Portfolio because of the additional energy
 10 efficiency investments, that is [BEGIN CONFIDENTIAL] [REDACTED] [END
 11 CONFIDENTIAL]⁶³ lower relative to the Recommended Portfolio load of 244
 12 TWh in 2040. Also, the inclusion of Bad Creek II helps maintain a dispatchable
 13 resource available to the Companies.

14 **Q CAN YOU EXPLAIN WHY THE NCSEA ALTERNATIVE PORTFOLIO**
 15 **SELECTS SIGNIFICANTLY LESS STANDALONE BATTERY STORAGE**
 16 **THAN THE REPRODUCED RECOMMENDED PORTFOLIO?**

17 A Yes. Bad Creek II, a pumped storage facility, has similar attributes and serves a
 18 similar purpose as battery storage resources. By including this resource as an
 19 exogenous addition in 2037, the model has less need to build battery storage
 20 resources that would otherwise have the same purpose with respect to dispatch and
 21 grid reliability.

⁶³ See Duke Energy Confidential Response NCSEA DR 7-11(c) (referring to Confidential Attachment “NCSEA DR 7-11c - UEE Hourly Load (Confidential).xlsx.”); see also Duke Energy Confidential Response to NCSEA DR 7-12 (referring to Confidential Attachment “NCSEA DR7-12 DEC High EE (Confidential).xlsb” and Confidential Attachment “NCSEA DR7-12 DEP High EE (Confidential).xlsb.”).

1 **Q ABOVE, YOU EXPLAINED THAT YOU DID NOT CHANGE DUKE**
2 **ENERGY’S EXOGENOUS COAL PLANT RETIREMENT SCHEDULE.**
3 **HOW WOULD YOU EXPECT COAL RETIREMENT DATES TO**
4 **CHANGE, IN COMPARISON TO DUKE ENERGY’S MODELING, IN THE**
5 **NCSEA ALTERNATIVE PORTFOLIO IF THEY WERE MODELED**
6 **ENDOGENOUSLY?**

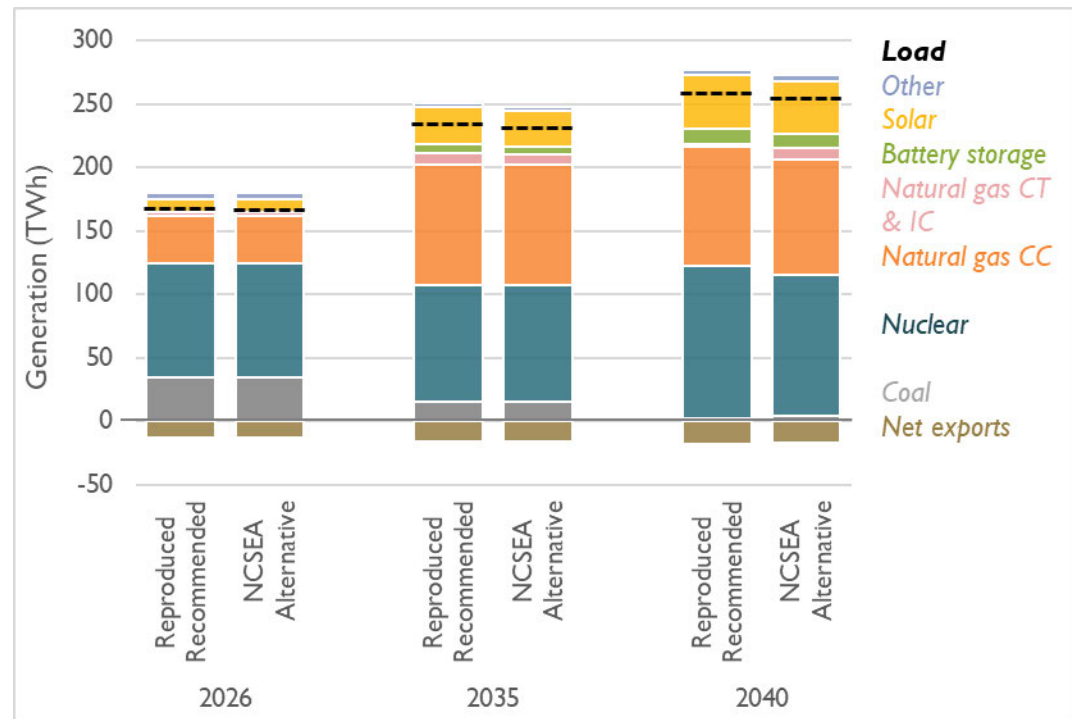
7 A Again, the NCSEA Alternative Portfolio contains greater energy efficiency
8 savings, and thus a lower load. Duke Energy therefore needs fewer MW of firm
9 capacity to meet load. I expect that if the model incorporated fixed costs from coal
10 and could retire coal resources endogenously, rather than having predetermined
11 retirement dates, some of the coal resources may retire earlier. However, by
12 maintaining the same exogenous coal plant retirement schedule created by Duke
13 Energy, the NCSEA Alternative Portfolio maintains sufficient capacity to defer the
14 addition of a natural gas combined cycle unit in 2032. In terms of “least-regrets,” a
15 temporary increased reliance on an existing asset provides greater flexibility for
16 alternative solutions to evolve that adequately maintain the reliability of the grid
17 and are more cost-effective.

18 **Q HOW DO GENERATION LEVELS BY RESOURCE TYPE DIFFER**
19 **BETWEEN THE REPRODUCED RECOMMENDED PORTFOLIO AND**
20 **NCSEA ALTERNATIVE PORTFOLIO?**

21 A Figure 3 below shows the generation results of the Reproduced Recommended
22 Portfolio and the NCSEA Alternative Portfolio. Although both portfolios have the
23 same quantity of coal capacity, the amount of generation from coal is lower than

the Reproduced Recommended Portfolio in the near term from 2026–2029. In addition, natural gas combined cycle capacity in the Reproduced Recommended Portfolio and the NCSEA Alternative Portfolio are the same until 2031, but generation is lower from natural gas combined cycle capacity in the NCSEA Alternative Portfolio from 2026–2031 as a result of load reduction from additional energy efficiency and additional demand response deployment compared to the Reproduced Recommended Portfolio.

Figure 3. Reproduced Recommended Portfolio and NCSEA Alternative Portfolio generation by resource type



Note: 'Other' includes demand response, pumped storage, hydro, biomass, and landfill. In the NCSEA Alternative, 'Other' includes demand response, PowerPair, hydro, pumped storage, biomass, and landfill. Generation from PowerPair program reaches 23 GWh by 2040.

1 **D The NCSEA Alternative Portfolio's PVRR and bill impacts**

2 **Q EXPLAIN HOW YOU CALCULATE PVRR FOR THE NCSEA**
3 **ALTERNATIVE PORTFOLIO.**

4 A I calculate revenue requirement in a post-processing step using the same set of
5 EnCompass outputs that Duke Energy uses in its EnCompass production cost
6 modeling. I also include the general category of costs that Duke Energy includes in
7 its revenue requirement outside of the EnCompass outputs it uses. Then I calculate
8 the PVRR from 2026 to 2040 using Duke Energy's combined utility discount rate
9 and the revenue requirement. I used an adapted version of Duke Energy's revenue
10 requirement model and find that my calculation of the PVRR for the Reproduced
11 Recommended Portfolio is within 1.1 percent of Duke Energy's calculation of the
12 PVRR for Duke Energy's Recommended Portfolio.

13 **Q HOW DO THE REVENUE REQUIREMENT AND PVRR COMPARE**
14 **BETWEEN THE REPRODUCED RECOMMENDED PORTFOLIO AND**
15 **THE NCSEA ALTERNATIVE PORTFOLIO?**

16 A The total cost to ratepayers is \$3.9 billion less in the NCSEA Alternative Portfolio
17 as compared to the Reproduced Recommended Portfolio over the study period.
18 Table 11 summarizes the PVRR results of these two portfolios. The PVRR of the
19 NCSEA Alternative Portfolio includes the incremental cost of the additional energy
20 efficiency, demand response, and PowerPair investments.

21

Table 11. PVRR (nominal \$ million) of Reproduced Recommended Portfolio and NCSEA Alternative Portfolio (2026–2040)

Source	Cost Category	Reproduced Recommended portfolio	NCSEA Alternative
EnCompass outputs	Carrying cost	\$21,567	\$17,318
	Fuel costs	\$43,064	\$43,526
	Program costs	-\$1,051	-\$1,051
	Commitment costs	\$231	\$242
	Non-fuel variable costs	\$3,024	\$2,938
	Fixed costs	\$11,488	\$10,166
	Contract cost	\$2,846	\$2,985
	PTC	-\$1,051	-\$1,051
External	PPA carrying cost	\$2,684	\$2,684
	BESS FOM	\$259	\$259
	Solar PPA	\$2,555	\$2,555
	Solar Paired Storage PPA	\$1,277	\$1,277
	Near-term ITC costs for PPAs	-\$749	-\$749
	PTC costs	-\$1,235	-\$1,235
	Nuclear fixed costs	\$591	\$591
	Coal fixed costs	\$2,163	\$2,163
	EE, DR, and PowerPair	\$6,037	\$7,164
Total Cost		\$93,700	\$89,783

Note: In both portfolios, retail revenue, contract revenue, sales revenue, purchase costs, ancillary sales, and ancillary purchases are \$0.

Q EXPLAIN HOW YOU CALCULATED BILL IMPACTS FOR THE NCSEA ALTERNATIVE PORTFOLIO.

A I calculate bill impacts for the NCSEA Alternative Portfolio in a similar method to Duke Energy's approach. However, Duke Energy used a different revenue requirement model for its bill impact analysis than it used to calculate the total cost of each portfolio. For Duke Energy, the bill impact model "a depreciating rate base over time . . . utilize[s] incremental O&M from 2026, include[s] retail allocation factors, include[s] CWIP in rate base on nuclear, OSW and combined cycles, include[s] coal securitization benefits and include amortization of the IRA tax

credits,”⁶⁴ Instead, I use same the revenue requirement that I used to calculate the PVRR. The costs that differentiate the two sets of revenue requirements—that is, the bill impact analysis and the system cost analysis—largely pertain to resources that are present in all scenarios (such as CWIP on nuclear). This means that the costs that differentiate the revenue requirement models are likely similar across scenarios and thus would not impact my bill impact calculations. Similar to Duke Energy, I calculate the cumulative percent increase from 2025 to 2035 and 2040. I then apply that percent increase to the typical residential household bill that Duke calculated in its bill impact analysis for 2025.

Q HOW DO THE BILL IMPACTS COMPARE BETWEEN THE REPRODUCED RECOMMENDED PORTFOLIO AND THE NCSEA ALTERNATIVE PORTFOLIO?

A Using my modified bill impact analysis, I find that the NCSEA Alternative Portfolio saves residential ratepayers \$5.83 per month in 2035 and saves residential ratepayers \$16.94 per month in 2040, compared to the Reproduced Recommended Portfolio. This is because the PVRR of the NCSEA Alternative Portfolio is \$3.9 billion less than the Reproduced Recommended Portfolio over the study period.

E The NCSEA Alternative Portfolio’s reliability results

Q EXPLAIN YOUR APPROACH FOR RELIABILITY MODELING.

A I model the NCSEA Alternative Portfolio in SERVVM for Duke Energy’s reliability benchmark years of 2035 and 2040. For each simulation, I use the same probabilistic SERVVM parameters as Duke, modeling 6,570 iterations consisting of

⁶⁴ **Exhibit DG-2**, See Duke Energy Response to NCSEA DR 3-11.

1 different combinations of 45 weather years, 50 forced-outage scenarios, and three
2 load forecast outcomes.

3
4 To create the studies, I duplicate Duke Energy's Preliminary Base SERVVM studies
5 and use the differences between Duke Energy's Preliminary Base Portfolio
6 EnCompass capacity outputs and the NCSEA Alternative Portfolio EnCompass
7 capacity outputs to adjust the resource capacities in SERVVM. For loads, I calculate
8 differences by year, season, and region between the EnCompass Preliminary Base
9 (Advancing Development) load inputs and High EE load inputs and develop a
10 corresponding High EE load forecast in SERVVM.

11 **Q DID YOU VERIFY THAT YOUR SERVVM APPLICATION PRODUCES**
12 **SIMILAR RESULTS AS DUKE ENERGY'S RECOMMENDED**
13 **PORTFOLIO?**

14 **A** Yes. As with the capacity expansion and production cost Encompass modeling, I
15 simulate Duke Energy's Recommended Portfolio studies as provided by Duke
16 Energy, without modification to ensure that the outputs match those that Duke
17 Energy published in its filing. There are minor calibration differences between my
18 reproduced results and those Duke Energy presented. I used an identical SERVVM
19 application file to Duke, so these minor differences are purely computational and
20 do not reflect any discrepancy in software version or methodology. These results
21 are presented Table 12.

Table 12. Reproduced reliability results⁶⁵

Reliability Metric	2035		2040	
	Recommended Portfolio	Reproduced Recommended Portfolio	Recommended Portfolio	Reproduced Recommended Portfolio
LOLE [event-day per year]	0.116	0.118	0.056	0.058
LOLH [event-hour per year]	0.350	0.361	0.100	0.110
EUE [MWh]	1,091	1,126	214	255
nEUE [ppm]	6.0	6.2	1.1	1.3

Notes: Reliability metrics are defined below.

Q IS THE NCSEA ALTERNATIVE RESOURCE PORTFOLIO YOU MODELED IN SERVIM CONSISTENT WITH YOUR ENCOMPASS OUTPUTS?

A As described above, I developed the SERVIM resource inputs for the NCSEA Alternative Portfolio by adjusting Duke Energy's Preliminary Base Portfolio SERVIM study using the differences between the Preliminary Base and NCSEA Alternative Portfolio resources. As a result, any differences between Duke Energy's Preliminary Base Portfolio and SERVIM inputs are also reflected in my NCSEA Alternative Portfolio inputs. In addition, for all resources besides DSM, I developed the inputs using net resource capacity differences from EnCompass aggregated across the system. This means that more granular regional differences are not reflected. Duke Energy models DEC, Progress East, and Progress West as a single co-dispatched area in SERVIM, so SERVIM minimizes loss-of-load events across

⁶⁵ See 2025 Carolinas Resource Plan, App'x C, at 103 (referring to Table C-52).

1 the entire modeled topology. Therefore, I do not expect the precise allocation of
2 resources to meaningfully affect the reliability results.

3
4 For storage resources, I round the capacity differences and apply incremental
5 adjustments by adding or removing 100 MW units that Duke had configured in the
6 model.⁶⁶ This is consistent with Duke Energy's approach to entering these
7 resources in SERVVM. These modeling approximations may lead to minor
8 differences in the resource capacities.

9 **Q HOW AND WHY DID YOU MODEL DSM IN SERVVM?**

10 A Similar to other resources, I adjust Duke Energy's Preliminary Base SERVVM
11 studies using the differences between the Preliminary Base Portfolio and NCSEA
12 Alternative Portfolio EnCompass outputs. However, Duke Energy set up DSM
13 capacities in SERVVM as monthly inputs by program, and each DSM program that
14 Duke Energy configured in SERVVM is specific to a region. I therefore calculate the
15 annual capacity differences from the EnCompass outputs by program. In order to
16 translate these differences to monthly values, I use program-specific scaling factors
17 derived from the monthly distribution of Duke Energy's 2035 Preliminary Base
18 DSM capacities in SERVVM. This program-level, region-specific approach better
19 preserves the structure of Duke Energy's existing DSM inputs.

⁶⁶ To accurately capture battery outage rates, storage resources must be modeled as individual units in SERVVM rather than aggregated into a single large resource—otherwise, the entire storage capacity could fail simultaneously. Since Duke Energy had already configured these resources in SERVVM, I adjusted the storage capacity by simply removing or adding existing units in the model.

1 **Q WHAT RELIABILITY METRICS DID YOU EVALUATE?**

2 A I evaluate the same reliability metrics as Duke Energy. Table C-35, below, is pulled
3 directly from Appendix C of Duke Energy's *2025 Carolinas Resource Plan*,
4 below.⁶⁷

Table C-35: Reliability Metric Definitions

Name	Abbreviation	Description	Unit	Threshold
Loss of Load Expectation	LOLE	The number of individual days with firm load shed. Does not reveal the magnitude, duration, or number of events.	event-day per year	North America: One event-day per 10 years or 0.1 event-days per year.
Loss of Load Hours	LOLH	The number of individual hours with firm load shed. Reveals the duration of an event.	event-hour per year	None in North America. Several European countries have established thresholds varying from three to five event-hours per year. ¹⁵
Expected Unserved Energy	EUE	The total amount of unserved energy in MWh. Reveals the magnitude or depth of event(s).	MWh	None established, but the Companies are engaged with current industry research on the role of this metric in reliability analysis.
Normalized Expected Unserved Energy	nEUE	Allows for comparison of EUE between study years and systems with differing loads.	ppm or %	None in North America. Australian states use 0.002%. ¹⁶
Negative Internal Margin	NIM	Informs on the number of hours in a year where the system would have shed load if not for external neighboring assistance. This metric is not reported for non-interconnected systems.	hour per year	None established.

5
6 These are probabilistic metrics that represent expected statistical outcomes
7 averaged across thousands of simulated iterations. They are not deterministic
8 measures of actual experienced outages. In other words, a LOLE of 0.1 does not
9 mean a loss-of-load event will occur in exactly one out of ten years; rather, it
10 reflects the probability-weighted likelihood of such events across a wide range of
11 possible conditions. In addition, it is important for the Commission to note that
12 Duke Energy uses a standard of 0.165 LOLE as a proxy for maintaining a 0.1 event-

⁶⁷ See *2025 Carolinas Resource Plan*, App'x C, at 70.

day per year threshold with the assistance of neighboring utilities.⁶⁸ Consistent with Duke Energy's reliability modeling, I conduct an islanded study of the NCSEA Alternative Portfolio in SERVIM and evaluate the LOLE against the 0.165 standard.

Q DOES THE NCSEA ALTERNATIVE SCENARIO MEET DUKE ENERGY'S RELIABILITY THRESHOLD IN 2035?

A Yes, the LOLE is less than 0.165. The NCSEA Alternative Portfolio is comparable to Duke Energy's Recommended Portfolio across all four metrics in 2035. The additional energy efficiency, demand response, and solar capacity in the NCSEA Alternative Portfolio ensures that it achieves similar reliability to Duke Energy's more costly Recommended Portfolio (*see* Table 13).

Table 13. Recommended and Alternative Portfolio reliability comparison, 2035⁶⁹

Reliability Metric	Recommended Portfolio	Reproduced Recommended Portfolio	NCSEA Alternative Portfolio
LOLE [event-day per year]	0.116	0.118	0.153
LOLH [event-hour per year]	0.350	0.361	0.494
EUE [MWh]	1,091	1,126	1,529
nEUE [ppm]	6.0	6.2	8.6

Q WHAT ARE YOUR CONCLUSIONS FROM THE 2035 RELIABILITY COMPARISON?

A The NCSEA Alternative Portfolio has additional energy efficiency and therefore lower load compared to the Reproduced Recommended Portfolio. All else being equal, this would generally lead to increased reliability. However, because this

⁶⁸ *See, id.*, at 74–75.

⁶⁹ *See 2025 Carolinas Resource Plan*, App'x C, at 103 (referring to Table C-52).

lower load defers utility-scale capacity additions using least cost optimization, fewer power plants and storage resources are online in 2035 in the NCSEA Alternative Portfolio. This reduction in firm capacity more than offsets the reduction in load, thereby leading to less optimal reliability metrics. Nevertheless, my findings show that the NCSEA Alternative Portfolio meets Duke Energy's reliability threshold in a more cost-effective, least-regrets way.

Q DOES THE NCSEA ALTERNATIVE SCENARIO MEET DUKE ENERGY'S RELIABILITY THRESHOLD IN 2040?

A Yes, the LOLE is within Duke Energy's threshold of 0.165 (*see* Table 14). Across the Recommended Portfolio, the Reproduced Recommended Portfolio, and the NCSEA Alternative Portfolio, these findings are based on long-term modeling assumptions and carry a high degree of uncertainty.

Table 14. Recommended and Alternative Portfolio reliability comparison, 2040⁷⁰

Reliability Metric	Recommended Portfolio	Reproduced Recommended Portfolio	NCSEA Alternative Portfolio
LOLE [event-day per year]	0.056	0.058	0.100
LOLH [event-hour per year]	0.100	0.110	0.251
EUE [MWh]	214	255	588
nEUE [ppm]	1.1	1.3	3.1

Q WHAT ARE YOUR CONCLUSIONS FROM THE 2040 RELIABILITY COMPARISON?

A Again, the lower load in the NCSEA Alternative Portfolio means that a reliable system can be achieved with less firm capacity online in 2040. By contrast, the

⁷⁰ *Id.*

1 Reproduced Recommended Portfolio involves costly overbuilding to meet the
2 reliability standard. For example, the Reproduced Recommended Portfolio requires
3 additional nuclear capacity in 2040, despite considerable uncertainty around Duke
4 Energy's assumptions for nuclear costs. The Reproduced Recommended Portfolio
5 exceeds the reliability standard, but it does so at a cost and increased risk to
6 ratepayers.

7 **F The NCSEA Combined Utility Portfolio**

8 **Q DID YOU INVESTIGATE HOW RECENT DEVELOPMENTS**
9 **REGARDING THE COMBINATION BETWEEN DEC AND DEP COULD**
10 **IMPACT YOUR FINDINGS?**

11 A Yes. In an alternative scenario with a combined DEC and DEP topology, I find cost
12 savings in comparison to the Reproduced Recommended Portfolio. Using the same
13 approach to EnCompass modeling described in the section on NCSEA Alternative
14 scenario inputs on page 38, I assessed the impact of a combined DEC and DEP in
15 the NCSEA Combined Utility Portfolio. In particular, I applied scenario datasets
16 relevant to Duke Energy's own modeling of a merged topology, relying on datasets
17 from Duke Energy's Utility Combination sensitivity. I then applied these datasets
18 to the NCSEA Alternative's scenario settings and analyzed them in EnCompass.

19 **Q DO YOU HAVE ANY CONCERNS WITH HOW DUKE ENERGY**
20 **MODELED ITS COMBINED UTILITY COMBINATION?**

21 A Yes. I observed several anomalies that complicate the comparison between the
22 NCSEA Combined Utility Portfolio and the NCSEA Alternative Portfolio. For
23 example, I note that in the Combined Utility sensitivity outputs from Duke Energy,

1 firm capacity ratings for certain resources (e.g., solar, distributed generation, wind,
2 battery storage) are lower than their analogous values in the Preliminary Base or
3 NTAP scenario outputs. This change in firm capacity ratings (which are inherited
4 in NCSEA's Combined Utility scenario via the datasets used in the Duke Energy's
5 Combined Utility sensitivity) are likely to yield different build profiles. Second, I
6 observe that Duke Energy's Combined Utility sensitivity has non-zero quantities of
7 estimated unserved energy ("EUE") in most years. Likewise, in the results
8 associated with the NCSEA Combined Utility Portfolio, I observe a nonzero
9 amount of estimated unserved energy ("EUE") in every year of my modeling except
10 2027 and 2035. This suggests that there is a setting inherent in Duke Energy's
11 Combined Utility input datasets that does not limit EUE in the same way it is
12 limited in the Preliminary Base and NTAP scenarios (through 2040) and all
13 scenarios run by Synapse. In most modeling exercises, I would aim for 0 MWh
14 EUE in every year modeled. But in this case, I chose to keep my modeling inputs
15 as close to Duke Energy's as possible.

16 **Q HOW DID THESE MODIFICATIONS REFLECTING A MERGED DEC**
17 **AND DEP TOPOLOGY IMPACT YOUR RESULTS?**

18 A I find that by 2040, the resource builds found in the NCSEA Combined Utility
19 Portfolio are largely the same as those found in the NCSEA Alternative Portfolio
20 (see Table 15), with a few notable exceptions: an additional 12 MW of PowerPair,
21 12 MW of demand response, and 1,117 MW of nuclear are built, while 1,283 MW
22 of gas-fired combustion turbines, 300 MW of solar, and 1,500 MW of battery
23 storage are avoided.

Table 15. Comparison of total capacity in the NCSEA Alternative and NCSEA Combined Utility Portfolios, 2040 (MW)

Resource type	NCSEA Alternative Portfolio	NCSEA Combined Utility Portfolio	Delta (<i>Combined Utility Portfolio less NCSEA Alternative Portfolio</i>)
Coal	849	849	-
Demand response	2,572	2,572	-
PowerPair Storage	38	50	12
Other	74	74	-
Natural Gas CC	12,928	12,928	-
Natural Gas CT	10,511	9,227	-1,283
Natural Gas IC	187	187	-
Hydro	1,398	1,398	-
Pumped Storage	4,300	4,300	-
Nuclear	13,668	14,785	1,117
Solar	18,826	18,526	-300
Wind	-	-	-
Battery Storage	8,208	6,708	-1,500
Total	73,558	71,604	-1,954

Q WHAT ARE THE ANNUAL CAPACITY ADDITIONS IN THE NCSEA COMBINED UTILITY PORTFOLIO COMPARED TO THE REPRODUCED RECOMMENDED PORTFOLIO?

A I find that by 2040, the NCSEA Combined Utility Portfolio builds 3.7 GW of resources less than the Reproduced Recommended Portfolio (*see* Table 16). Notably, the NCSEA Combined Utility Portfolio builds an additional 156 MW of demand response, adds 50 MW of PowerPair, and builds 1,760 MW of pumped storage (Bad Creek II) compared to the Reproduced Recommended Portfolio. The NCSEA Combined Utility Portfolio avoids building 1,365 MW of natural gas combined cycle capacity, 855 MW of natural gas combustion turbine capacity, 525 MW of solar, and 2,900 MW of battery storage.

Table 16. Comparison of total capacity in the NCSEA Combined Utility and Reproduced Recommended Portfolios, 2040 (MW)

Resource type	Reproduced Recommended Portfolio	NCSEA Combined Utility Portfolio	Delta (<i>Combined Utility Portfolio less Reproduced Recommended Portfolio</i>)
Coal	849	849	-
Demand response	2,416	2,622	156
PowerPair Storage	-	50	50
Other	74	74	-
Natural Gas CC	14,293	12,928	-1,365
Natural Gas CT	10,083	9,227	-855
Natural Gas IC	187	187	-
Hydro	1,398	1,398	-
Pumped Storage	2,540	4,300	1,760
Nuclear	14,785	14,785	-
Solar	19,051	18,526	-525
Wind	-	-	-
Battery Storage	9,608	6,708	-2,900
Total	75,284	71,604	-3,679

Q DO BOTH THE NCSEA ALTERNATIVE PORTFOLIO AND NCSEA COMBINED UTILITY PORTFOLIO DEFER 1,365 MW OF NATURAL GAS COMBINED CYCLE GENERATION?

A Yes. In addition, the NCSEA Combined Utility Portfolio avoids 855 MW of natural gas combustion turbine generation compared to the Reproduced Recommended Base Portfolio. As in the NCSEA Alternative Portfolio, additional energy efficiency and DSM help to lower the demand for electricity and thereby defer the need to build large central station power plants at uncertain prices. Together with the addition of Bad Creek II (a pumped storage facility built using mature, well-understood technology) these resources potentially save ratepayers money by enabling the deferral of large, centralized capital-intensive resources.

1 **Q DOES THE NCSEA COMBINED UTILITY PORTFOLIO INCLUDE THE**
2 **SECOND UNIT OF LLWR THAT WAS NOT SELECTED BY THE NCSEA**
3 **ALTERNATIVE PORTFOLIO?**

4 A Yes. In the NCSEA Combined Utility Portfolio, an additional 1,117 MW of nuclear
5 generating capacity is built in 2037. However, this demonstrates that nuclear
6 technologies, as with other long lead resources in past CIPRP proceedings, can be
7 a “ductile” resource.⁷¹ Specifically, the NCSEA Alternative Portfolio and the
8 NCSEA Combined Utility Portfolio demonstrate that the second unit of a LLWR
9 generation asset does not need to arrive by a specific year for the Companies to
10 maintain a reliable grid in the near term. As a result, it does not need to be approved
11 as reasonable for planning purposes in this CIPRP proceeding.

12 **Q DID YOU COMPLETE A PVRR ANALYSIS FOR THE NCSEA**
13 **COMBINED UTILITY PORTFOLIO?**

14 A Yes. I find that the NCSEA Combined Utility Portfolio yields a 2.9 percent higher
15 PVRR than the NCSEA Alternative Portfolio, and a 0.9 percent greater PVRR than
16 Duke Energy’s Combined Utility Sensitivity Portfolio. I compare the NCSEA
17 Combined Utility Portfolio with Duke Energy’s Combined Utility Sensitivity
18 Portfolio and not a Reproduced Combined Utility Portfolio. As shown by the results
19 of the Reproduced Preliminary Base and the Reproduced Recommended portfolios,
20 a hypothetical Reproduced Combined Utility Portfolio should yield similar results
21 to Duke Energy’s Combined Utility Sensitivity Portfolio. I also apply my

⁷¹ See 2023-2024 CIPRP Order, at 143–44 (concluding that offshore wind was a highly “ductile” or influenced resource as it would be selected in different years depending on the inputs and assumptions of different scenarios and sensitivities).

1 calculation methodology to Duke Energy's Combined Utility Sensitivity Portfolio.
2 Using my methodology, I calculate a PVRR of \$92.522 billion from 2026-2040 for
3 Duke Energy's Combined Utility Sensitivity Portfolio, which is within 0.03% of
4 Duke Energy's own PVRR calculation for the same portfolio.

5
6 As the PVRR for the NCSEA Combined Utility Portfolio is only 0.9 percent greater
7 than Duke Energy's Combined Utility Sensitivity Portfolio, I note that this is very
8 likely within the analyses' margin of error. In addition, because of the modeling
9 abnormalities present in all of Duke Energy's combined utility analyses (discussed
10 above), it is possible that the NCSEA Combined Utility Portfolio could be less
11 expensive than Duke Energy's Combined Utility Sensitivity Portfolio if Duke
12 Energy's inputs were corrected. Notwithstanding these abnormalities present in all
13 of Duke Energy's combined utility analyses, the NCSEA Combined Utility
14 Portfolio demonstrates that the biggest driver in costs for ratepayers in these plans
15 is the additional 1,117 MW of nuclear generating capacity built in 2037. Given the
16 uncertainties of the topology of Duke Energy's Combined Utility Sensitivity
17 Portfolio, and the uncertainties of the nuclear technology that Duke Energy plans
18 to deploy,⁷² the Commission should not approve the additional 1,117 MW of
19 nuclear as reasonable for planning purposes in this proceeding.

20
21 Overall, my findings for this portfolio are much the same as in the NCSEA
22 Alternative Portfolio, suggesting that the combination between DEC and DEP

⁷² 2025 Carolinas Resource Plan, App'x J, at 26, 31-34.

1 would not materially affect my findings and that the inclusion of more energy
2 efficiency, more demand response, an expansion of PowerPair, and the addition of
3 Bad Creek II would likely provide lower costs to ratepayers.

4 **Q DID YOU MODEL THE RELIABILITY OF THE ALTERNATIVE**
5 **SCENARIO UNDER A COMBINED UTILITY SENSITIVITY?**

6 A No. Consistent with Duke Energy's approach, I did not model the reliability of the
7 Combined Utility sensitivity.

8 **G Key findings**

9 **Q WHAT ARE THE KEY FINDINGS AND RECOMMENDATIONS FROM**
10 **THE NCSEA MODELING?**

11 A I find that the NCSEA Alternative Portfolio is more cost-effective and just as
12 reliable as the Reproduced Recommended Portfolio. Because of the similarities in
13 Duke Energy's Preliminary Base Portfolio and Duke Energy's Recommended
14 Portfolio compared to the Reproduced Base Portfolio and Reproduced
15 Recommended Portfolio, I also find that the NCSEA Alternative Portfolio is more
16 cost-effective and just as reliable as Duke Energy's Recommended Portfolio. This
17 indicates that the NCSEA Alternative Portfolio is the least-regrets portfolio.

18
19 To ensure reliability, reduce system costs, reduce costs to ratepayers, and minimize
20 risk, Duke should pursue greater energy efficiency savings, expand its demand
21 response programs, including PowerPair, and expand its pumped hydro storage
22 capacity through bringing Bad Creek II online by 2037.

1 **Q TO BE CLEAR, DESPITE THIS KEY FINDING, NCSEA IS NOT**
2 **RECOMMENDING A PRESCRIPTIVE LEVEL OF ENERGY**
3 **EFFICIENCY, DSM, OR POWERPAIR?**

4 A No. The modeling Synapse completed quantifies the significant value that energy
5 efficiency, DSM, and PowerPair provide. By reducing electricity consumption and
6 reducing peak demand for electricity, energy efficiency, DSM, and PowerPair
7 resources can help to defer the need for costly, uncertain central-station power
8 plants and reduce costs for ratepayers. Any additional savings above 1 percent of
9 eligible retail sales directly benefits Duke Energy's customers.

10 **Q HOW DOES SOLAR ENERGY CONTRIBUTE TO A LEAST COST**
11 **PORTFOLIO?**

12 A Throughout Duke Energy's analysis, solar energy is a primary source of new
13 generation in 2026–2040. In every key portfolio informing the NTAP amount of
14 solar described in the 2025 CPIRP,⁷³ there is at least 1,650 GW of solar built by
15 2031 in addition to 4,686 MW of solar under development.⁷⁴ When combined with
16 other resources, such as conventional pumped storage resources, battery storage
17 resources, and DSM resources, solar can have an even bigger role in Duke Energy's
18 electric system, as shown by my NCSEA Alternative Portfolio and NCSEA
19 Combined Utility Portfolio.

⁷³ See *2025 Carolinas Resource Plan*, Ch. 3, at 24 (referring to Table 3-12: Solar Selections in Key Portfolios Informing NTAP Amount comparing the Preliminary Base with the High Gas Price, No Wind Availability, Low Solar Cost, High Solar & Storage Availability, High Load, and Moderate Development Load portfolios.).

⁷⁴ See *id.*; see also *2025 Carolinas Resource Plan*, App'x C, at 23 (referring to Table C-8: Forecasted Solar Capacities (Nameplate MW)).

1 **Q WHAT SHOULD THE COMMISSION TAKE AWAY FROM THE**
 2 **MODELING SYNAPSE COMPLETED FOR NCSEA?**

3 A The NCSEA Alternative Portfolio is more cost-effective than Duke Energy's
 4 Recommended Portfolio. It meets reliability requirements both in the near term and
 5 through a longer, more uncertain timeframe. As a result, NCSEA's alternative
 6 modeling represents the least-regrets path forward.

7 **V ECONOMIC AND REGULATORY FACTORS IMPACTING THE CPIRP**

8 **Q DO DUKE ENERGY'S COST AND TIMING ASSUMPTIONS FOR GAS**
 9 **TECHNOLOGIES INTRODUCE UNNECESSARY RISK FOR**
 10 **RATEPAYERS?**

11 A Yes. As discussed above, Duke incorporated ELNG as an available resource in its
 12 modeling as a result of anticipated future conditions for low firm pipeline access.
 13 ELNG is an immature technology that creates unnecessary risk exposure for
 14 ratepayers. Duke assumes that all gas plants require ELNG facilities in [BEGIN
 15 CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL] and have an implied price
 16 [BEGIN CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL]
 17 relative to a traditional combined cycle plant without ELNG.⁷⁵ ELNG facilities
 18 have not yet been built anywhere in the United States,⁷⁶ making this assumed price

⁷⁵ See **Exhibit DG-3**, Duke Energy Corrected Response to PS DR 6-13; see also Duke Energy CONFIDENTIAL Response to Public Staff 10-3(b); see also Duke Energy Confidential Response to Public Staff DR 16-1(e) (referring to the data within Confidential attachment "CONFIDENTIAL PS DR 16-1-e Duke Energy LNG Generic - Base Case.xlsx, at tabs "ELNG Base Case!H12"); see also Duke Energy Confidential Response to Public Staff DR 1-7 (referring to Confidential Attachment "PS DR 1-7 IRP Generic Unit Summary DEC DEP (Confidential).xlsx, at tabs "2025 IRP Summary_IRP!AB10").

⁷⁶ See *Supplemental Direct Testimony of H. Lee Mitchell, IV on Behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, Dkt. No. E-100, Sub 207, 3-4 (Dec. 19, 2025) (citing *Direct Testimony of*

1 and timeline uncertain. Furthermore, increasing the share of the Companies'
 2 generation that comes from natural gas will further increase its exposure to fuel
 3 price volatility and rate shocks during sustained extreme weather events or
 4 geopolitical events, regardless of storage capacity.

5 **Q EXPLAIN THE RISKS POSED TO RATEPAYERS BY FUEL PRICE**
 6 **VOLATILITY.**

7 A High reliance on gas resources can expose ratepayers to fuel price volatility for
 8 which ratepayers cannot plan. Gas is a global commodity, which means that both
 9 domestic and global market forces can impact the price and demand for the
 10 resource. We are seeing this right now with the Iran conflict limiting the movement
 11 of oil tankers through the Strait of Hormuz.⁷⁷ Gas prices also regularly spike during
 12 extreme weather events, such as we saw during winter storm Uri in February 2022,
 13 winter storm Elliot in December 2022, and winter storm Fern January 2026.⁷⁸

14 **Q EXPLAIN MORE ABOUT HOW GLOBAL CONFLICTS IMPACT**
 15 **NATURAL GAS PRICES IN THE UNITED STATES.**

16 A After roughly doubling from 2019 to 2023,⁷⁹ North American liquid natural gas
 17 export capacity is projected to double between 2025 and 2029 from current levels

Jeffery C. Miscikowski on behalf of Virginia Electric and Power Company, Case No. PUR-2024-00096 (Va. State Corp. Comm'n, Nov. 19, 2024) (identifying proposed plants in Virginia and Wisconsin and a shuttered LNG facility in Massachusetts).

⁷⁷ L. Kilian, et al., *What the closure of the Strait of Hormuz means for the global economy*, FED. RESERVE BANK OF DALLAS, (Mar. 20, 2026), <https://www.dallasfed.org/research/economics/2026/0320>.

⁷⁸ Chris Newman, *Henry Hub Prices Smash All-Time Records as Winter Storm Fern, LNG Tag-Team to Tighten Balances*, NAT. GAS INTELLIGENCE (Jan 28, 2026), <https://naturalgasintel.com/news/henry-hub-prices-smash-all-time-records-as-winter-storm-fern-lng-tag-team-to-tighten-balances/>.

⁷⁹ Victoria Zaretskaya, *North America's LNG export capacity is on track to more than double by 2028*, U.S. ENERGY INFO. ADMIN. (Dec. 30, 2024), <https://www.eia.gov/todayinenergy/detail.php?id=64128>.

1 of 11.4 billion cubic feet per day at the beginning of 2024 to more than to more
 2 than 24 billion cubic feet per day in 2029.⁸⁰ To put this in perspective, U.S. total
 3 gas consumption in 2025 averaged roughly 92 billion cubic feet per day.⁸¹ The
 4 global market consumption effect on prices in the United States will continue to
 5 increase significantly over even the next few years.

6
 7 When the market is constrained and prices spike, those costs are passed directly to
 8 ratepayers. This happened recently in 2022 when Russia invaded Ukraine and
 9 European gas customers increasingly relied more on U.S. gas production. This
 10 drove up domestic gas prices, and those high costs were passed directly to
 11 ratepayers. For example, in the 2023 DEC annual fuel and fuel-related charge
 12 adjustments proceeding, Docket No. E-7, Sub 1282, DEC reported an under-
 13 recovery of fuel costs of approximately \$998 million during the test period ending
 14 December 31, 2022.⁸² This phenomenon also occurred in Michigan during the DTE
 15 Electric Company 2022 Fuel Reconciliation Docket. There, DTE noted that gas
 16 spending was 74 percent higher than planned. As a result, DTE requested recovery
 17 of an additional \$154 million for 2022 fuel costs alone.⁸³ Absent action from the
 18 Commission, Duke Energy and its shareholders are not impacted by these gas price

⁸⁰ Jordan Young, *North America's LNG Export Capacity Could More Than Double by 2029*, U.S. ENERGY INFO. ADMIN. (Oct. 16, 2025), <https://www.eia.gov/todayinenergy/detail.php?id=66384>.

⁸¹ *Natural Gas: Natural Gas Consumption by End Use* (Feb. 27, 2025), https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

⁸² See, generally, *Supp. Testimony of Sigourney Clark for Duke Energy Carolinas, LLC*, Dkt. No. E-7, Sub 1282 (May 4, 2023) (Clark Revised Exhibit 3 calculates the significant under-recovery of fuel and fuel-related costs).

⁸³ DTE Elec. Co. 2023. *Exhibit A-7*. Mich. Pub. Serv. Comm'n Docket No. E-21051. (Mar. 31, 2023).

spikes while ratepayers are paying for them in their entirety. Duke Energy should account for this in its CPIRP modeling and in planning its future resource mix. Reducing its reliance on fossil-based resources is the best way to protect its ratepayers from these future price volatility risks.

Q WHAT RISKS DOES DUKE ENERGY FACE FROM CONTINUED RELIANCE ON COAL ASSETS?

A The coal market has seen dramatic price volatility in parts of the United States over the past few years.⁸⁴ There have also been labor challenges both at the mines and the railroad companies that transport the coal, as coal workers demand better pay and have more options in the labor market.⁸⁵ Additionally, as an increasing number of coal plants across the United States retire and the demand for coal contracts, coal companies could consolidate. Concentration of coal supply in a few companies means less competition, which in turn can lead to higher coal prices.⁸⁶

Electric power sector coal consumption was down in 2025 relative to prior years and accounted for around 13 percent of generating capacity and 17 percent of total utility-scale generation.⁸⁷ This is a novel trend because coal's national market share of electric generation had been around 20 percent each month between 2020–2022;

⁸⁴ *Coal: Coal Markets*, U.S. ENERGY INFO. ADMIN. (Mar. 23, 2026), <https://www.eia.gov/coal/markets/>.

⁸⁵ *2025 Carolinas Resource Plan*, App'x F, at 6.

⁸⁶ *See id.*, at 3–4. *See also* *2023 Carolinas Resource Plan*, App'x F - Coal Retirement Analysis, Dkt. No. E-100, Sub 190, 2–3 (Aug. 17, 2023) (same, addressing the risks of coal producer consolidation).

⁸⁷ *Electricity: Electric Power Monthly*, U.S. ENERGY INFO. ADMIN., [eia.gov/electricity/monthly/epm_table_grapher.php?t=table_1_01](https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_1_01) (last visited Mar. 28, 2026) (Referring to Table 1.1: Net Generation by Energy Sour: Total – All Sectors 2016-January 2026, Table 1.1, which shows generation from coal dropped to 737,151 GWh in 2025 compared to 1,239,149 GWh in 2016).

1 and prior to 2020, coal had never comprised less than 20 percent of the market in
 2 any month.⁸⁸ Additionally, risks from increased environmental regulation, as I will
 3 discuss next, could result in higher costs and higher risks. Higher risk impacts not
 4 just resource planning economics, but also company risk profiles, which can lead
 5 to downgraded credit ratings and can impact access to capital.

6 **Q HOW DOES DUKE ENERGY'S BUILD PLAN IMPACT REGULATORY**
 7 **UNCERTAINTY AND RISK TO ENVIRONMENTAL COMPLIANCE?**

8 A The cost of operating Duke Energy's existing fossil resources is still high and the
 9 regulatory risk they face is real. Coal units will continue to face uncertain regulatory
 10 and environmental compliance costs from existing federal and state rules and new
 11 rules in the future. This regulatory uncertainty poses a substantial risk to ratepayers,
 12 even if Section 111 Rules are repealed in their current form.

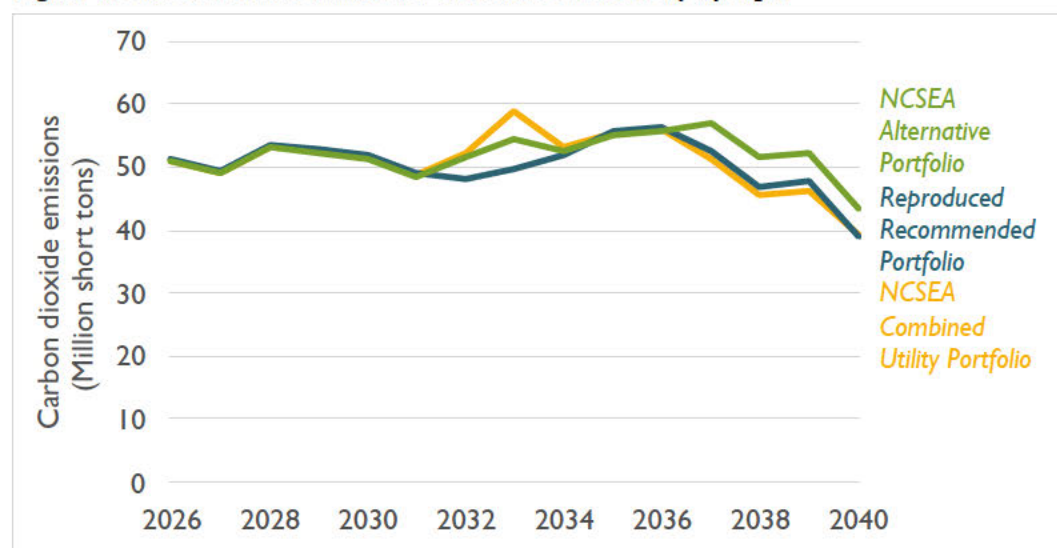
13 **Q HOW DO CARBON DIOXIDE EMISSIONS COMPARE BETWEEN THE**
 14 **REPRODUCED RECOMMENDED PORTFOLIO AND THE NCSEA**
 15 **ALTERNATIVE PORTFOLIO?**

16 A Carbon dioxide emissions between the three portfolios are similar in the near-term
 17 period. Through 2031, the Reproduced Recommended portfolio emits 2.3 million
 18 short tons of carbon dioxide more than the NCSEA Alternative portfolio and 1.3
 19 million short tons more than the NCSEA Combined Utility Portfolio. From 2026 to
 20 2040, the NCSEA Alternative Portfolio emits, on average, 1.6 million short tons
 21 more than the Reproduced Recommended portfolio annually. From 2026 to 2040,

⁸⁸ Seth Feaster, *Coal Use at U.S. Power Plants Continues Downward Spiral; Full Impact on Mines to be Felt in 2024*, INST. FOR ENERGY ECON. & FIN. ANALYSIS (Nov. 2, 2023), <https://ieefa.org/resources/coal-use-us-power-plants-continues-downward-spiral-full-impact-mines-be-felt-2024>.

the NCSEA Combined Utility Portfolio emits, on average, 0.6 million short tons of carbon dioxide more than the Reproduced Recommended Portfolio annually. Total carbon dioxide emissions over the study period (2026–2040) are 3 percent lower in the Reproduced Recommended Portfolio compared to the NCSEA Alternative Portfolio and 1 percent lower compared to the NCSEA Combined Utility Portfolio. This difference in emissions is largely caused by the NCSEA Alternative Portfolio and NCSEA Combined Utility Portfolio deferring the addition of gas-fired generation and relying more on existing resources (*i.e.*, coal). I also note that for all portfolios, total carbon dioxide emissions could be greater than estimated here if carbon dioxide emissions related to ELNG facilities owned by Duke Energy are taken into account—these facilities could produce emissions or leak emissions in quantities not accounted for in this analysis.

Figure 4. Carbon dioxide emissions in scenarios modeled by Synapse



Q DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes.