Carbon-Free by 2050

Pathways to Achieving North Carolina's Power-Sector Carbon Requirements at Least Cost to Ratepayers

Prepared for North Carolina Sustainable Energy Association, Southern Alliance for Clean Energy, Natural Resources Defense Council, and the Sierra Club

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EXECUTIVE SUMMARY

This report evaluates the proposed Carbon Plan filing in North Carolina by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP), (collectively, Duke Energy or Duke), and, using the shared foundation of Duke Energy's modeling database, revises several inputs to bring them more in line with real-world conditions and presents new resource portfolios that would meet carbon requirements more cost-effectively than Duke Energy's proposal.

Synapse Energy Economics, Inc. (Synapse) has years of experience reviewing Integrated Resource Plans (IRPs), including Duke's 2018 and 2020 IRPs. For this proceeding, Synapse used EnCompass capacity expansion and production cost modeling software to model the Duke Energy system and identify the most cost-effective resource pathway for North Carolinians. This is the first proceeding in the Carolinas in which Duke Energy is also using the EnCompass software.

Using Duke's own EnCompass modeling database as a shared foundation, Synapse revised specific model inputs and allowed the EnCompass model to re-optimize for the most economic resource portfolio. This report presents the results of that revision and re-optimization across two scenarios: The *Optimized* scenario, which allows EnCompass to choose the optimal scenario based on those revised inputs, and the *Regional Resources* scenario, which additionally allows EnCompass to select Midwest wind resources procured via power purchase agreements through the PJM Interconnection (PJM). Synapse also reviews several manual adjustments made by Duke Energy in EnCompass to their Carbon Plan proposals, which deviate from resource planning best practices and add additional costs to ratepayers. The report discusses Duke Energy's EnCompass post-processing in Section 4, and specific changes to Duke Energy's modeling assumptions can be found in Appendices A and B.

The scenarios modeled by Synapse yield large cost savings relative to Duke's Portfolio 1 – Alternate, the only scenario proposed in Duke Energy's Carbon Plan filing designed to reach North Carolina House Bill 951 (HB 951)'s 70% reduction requirement by 2030 without assuming additional Appalachian firm gas transportation capacity.[1] Synapse used this portfolio as a baseline, against which it compared the resource trajectories and costs of the *Optimized* and *Regional Resources* scenarios. Total net capacity changes and net present value revenue

[1] Duke Energy's production cost modeling found that, despite being designed to meet the carbon requirements in in 2030, Portfolio 1 – Alternate would not actually achieve 70 percent reduction in carbon emissions by 2030; See Duke Energy Carbon Plan Appendix E (Appendix E), p. 89.

requirement (NPVRR) 2022-2050 for each Synapse portfolio are shown below in Figure 1 and Table 1.

Figure 1. Capacity by Resource Type, 2022 and 2050, by Scenario

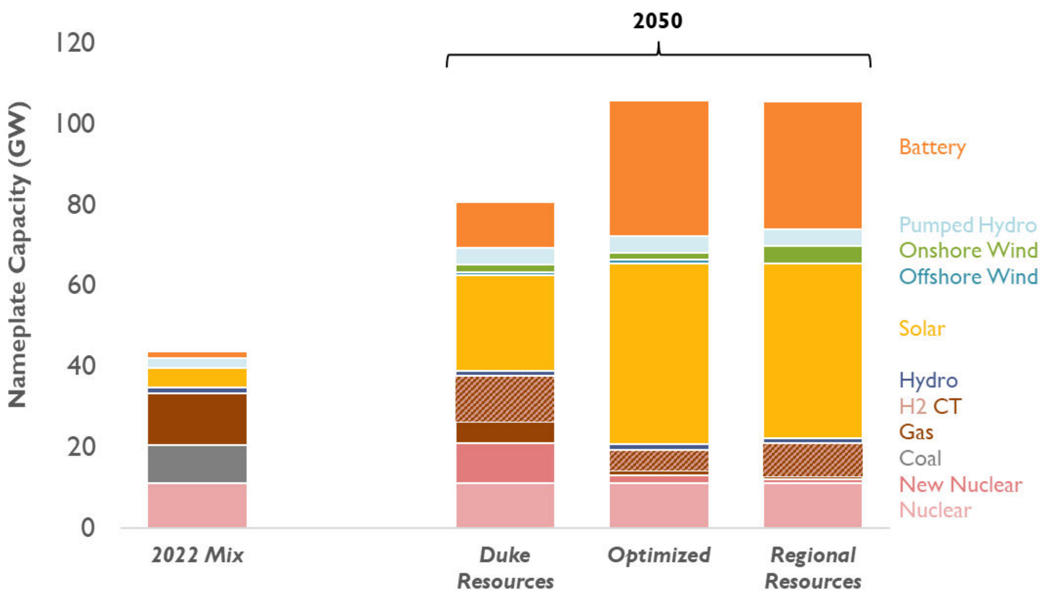

Table 1. Net Present Value Revenue Requirement over Time by Portfolio

Results (2022-2050)	*Duke Resources*	*Optimized*	*Regional Resources*
2030 NPVRR ($B)	$36.7	$36.0	$34.3
2040 NPVRR ($B)	$77.7	$69.8	$65.8
2050 NPVRR ($B)	$121.2	$103.5	$98.1

Synapse's modeling shows that, compared to the *Duke Resources* scenario that models the "Portfolio 1 -Alternate" scenario proposed in Duke Energy's Carbon Plan filing, scenarios that rely on proven energy efficiency, solar, storage, and wind resources can deliver a reliable, de-carbonized grid at a lower cost to ratepayers. The most economic path for North Carolina ratepayers requires (i) investing in energy efficiency to cost-effectively reduce overall load; (ii) accelerating deployment and maximizing the value of renewable energy resources; (iii) limiting undue reliance on investments in unproven nuclear technologies and uncertain hydrogen generation; and (iv) avoiding capital investments in risky additional gas-fired generation. Key results of Synapse's analysis include:

- Synapse's analysis shows that **compared to the *Duke Resources* scenario, net present value of revenue requirements savings from the Synapse scenarios range between $700 million and $2.4 billion (2 to 7 percent) through 2030.** By 2050, the range of savings increases considerably, from $17.7 to $23.1 billion (15 to 19 percent) across the Synapse scenarios.

- Synapse's *Optimized* and *Regional Resources* scenarios include utility energy efficiency savings that increase to incremental annual savings of 1.5 percent of total retail load. **Including additional achievable and cost-effective energy efficiency results in the Duke Energy system requiring 2 percent less energy in 2035 and 5 percent less energy in 2050** compared to Duke Energy's baseline energy efficiency assumption. Synapse's analysis shows that increased energy efficiency alone could save ratepayers billions of dollars on an NPVRR basis by 2050.

- Synapse's scenarios **do not select any additional gas combined-cycle (CC) or combustion turbine (CT) units across any portfolio,** despite these resources being available to the economic optimization algorithm model. Synapse's scenarios also rely less on unproven, uncertain future resources like new nuclear technology and zero-carbon hydrogen availability.

- Synapse's scenarios **economically retire 3.5 gigawatts (GW) of coal capacity earlier than the *Duke Resources* scenario** as the system shifts to more economical and less emissions-intensive power.

- Synapse's scenarios select solar, storage and onshore wind to meet energy and capacity needs. In the *Optimized* scenario, EnCompass selects **7.2 GW of incremental solar and 5.6 GW of storage by 2030.** By 2040, the *Optimized* scenario builds a cumulative 22.5 GW of incremental solar, 800 MW of offshore wind, 1.5 GW of onshore wind, and 17 GW of energy storage resources compared to today.

- In the final years of the planning period, Synapse's scenarios **economically retire between 800 and 1,300 megawatts (MW) of existing gas resources, rather than have them undergo retrofits to burn hydrogen.** Combined with ongoing technical and economic uncertainty around hydrogen retrofits, these retirements underscore the risks posed to gas-fired resources.

- Synapse's *Regional Resources* scenario allows EnCompass to choose wind power purchase agreements from the Midwest, as evaluated by the North Carolina Transmission Planning

Collaborative.[2] **Allowing the system to procure 2.5 GW of cost-effective Midwest wind resources results in $1.7 billion in savings to ratepayers by 2030 and $5.4 billion by 2050.** This result demonstrates the ability for regional coordination and transmission to deliver savings to for ratepayers.

- Synapse also performed a sensitivity that assessed the impact on carbon emissions if the Carolinas participated in the Regional Greenhouse Gas Initiative (RGGI). **Synapse finds that RGGI would drive emissions reductions of hundreds of thousands of tons per year in the 2020s and 2030s.**

Synapse's model generates these results while meeting reserve margin requirements established by Duke Energy in every month between 2022-2050. Synapse's modeling reliably meets load in every hour modeled, with no loss of load or unserved energy.

Table 2, below, summarizes near-term actions necessary to launch implementation of the Synapse portfolios. These procurement and analysis activities represent a "no-regrets" series of steps that Duke Energy and stakeholders, with oversight from the North Carolina Utilities Commission (NCUC) and subject to regulatory approvals, can take on the path toward cost-effective, low-carbon power in North Carolina.

Table 2. Short-Term Execution Plan

Resource	Amount	Proposed Near-Term Actions
Proposed Resource Selections: In-Service through 2030		
Energy Efficiency	1.5 percent of retail load	• Expand utility energy efficiency savings targets to 1.5 percent of total retail load
Distributed Energy Resources	At least 1 GW by 2035	• Develop and support programs to empower customer-owned energy resources to accelerate contribution to grid needs
Additional Solar	7,200 MW	• Invest in transmission projects to unlock additional cost-effective solar power • Begin procurement of 4 GW of new solar 2022-2024 with target in-service dates of 2025-2028 • Develop interconnection methods that will be robust long-term
Battery Storage	5,600 MW	• Begin procurement for 4 GW of stand-alone storage with target in-service dates of 2025-2028

[2] North Carolina Transmission Planning Collaborative (2022, May). Report on the NCTPC 2021 Public Policy Study. Retrieved at: http://www.nctpc.org/nctpc/document/REF/2022-05-10/NCTPC_2021_Public_Policy_Study_Report_05_10_2022_Final_%20Draft.pdf.

		• Invest in operational capabilities for capitalizing on energy storage resources for grid services
Onshore Wind *(in-state)*	900 MW	• Engage with communities on onshore wind siting • Prepare for continued advancement of onshore wind, long-term
Onshore Wind *(Midwest)*	2,500 MW	• Engage in inter-regional coordination with PJM for facilitating power purchase • Integrate Midwest wind import into short-term transmission planning
Offshore Wind	800 MW	• Initiate development and permitting activities for 800 MW, with eye toward potential additional procurement long-term
Proposed Resource Selections: Options for Long-Term Cost-Effective Carbon Reductions		
Coal Retirement	--	• Develop retirement plans for coal units consistent with economic optimization
Transmission Planning	--	• Develop processes for long-term, prospective and regional transmission planning that can cost-effectively meet economic and carbon reduction requirements of HB 951
Pumped Storage Hydro	1,700 MW	• Conduct feasibility study, develop EPC strategy, and apply at FERC for re-licensing
Hydrogen Planning	--	• Develop more detailed hydrogen fuel cost planning methodology • Conduct studies of hydrogen transport, storage, and distribution • Integrate cost of production and distribution into resource planning

The Carbon Plan process presents an opportunity for North Carolinians to envision what their clean energy future looks like and take decisive steps in that direction. Synapse's analysis charts a path toward a clean energy future that capitalizes on demand-side resources, moves decisively to exit coal generation, avoids unnecessary new gas generation, and deploys proven zero-emissions renewable energy resources at scale, achieving the statutory carbon reduction mandates for 2030 and 2050 at less cost than the Duke Resources scenario.

1. INTRODUCTION

Governor Roy Cooper signed North Carolina House Bill 951 into law on October 13, 2021. Among other things, the bill law directs the North Carolinas Utilities Commission to "take all reasonable steps" to achieve a 70 percent reduction in carbon emissions from the state's power sector by 2030 and carbon neutrality by 2050.[3] The law further requires the NCUC to develop a "Carbon Plan" by December 31, 2022 that achieves these goals. To implement its mandate, the NCUC directed Duke Energy to submit a proposed "Carbon Plan" that achieves these goals and provided that intervenors could file comments on Duke's proposal as well as their own alternative plans. In keeping with core principles of regulating utilities in the public interest and as required by HB 951, the Carbon Plan's resource pathways must also meet ratepayers' energy needs affordably and reliably.

Duke Energy's proposed Carbon Plan filing includes several proposed portfolios of new generation resources designed to meet North Carolinians' energy needs over the long-term, only one of which achieves HB 951's 70 percent reduction requirement by the default 2030 deadline ("Portfolio 1").[4] Each portfolio includes a case where, as directed by the Commission, additional firm gas transport capacity is unavailable,[5] and a case where some additional firm gas transport capacity is available. Cases where additional firm Appalachian gas transport capacity is unavailable are designated as "Alternate" in Duke Energy's proposed Carbon Plan filing.

Duke's proposed portfolios each include two technologies that have yet to be commercially deployed in power generation: small, modular nuclear reactors (SMRs) and widespread production, transport, and storage of hydrogen to either blend into the current gas supply or burn in specialized combustion turbines (CTs). Duke's Carbon Plan proposals place undue reliance on these technologies, rather than commercially available, proven zero-carbon generation and storage technologies combined with investment in energy efficiency, demand response, and transmission, which are elements that high-quality national decarbonization models cite as hallmarks of least-cost power generation in the transition to a low-carbon

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[3] North Carolina House Bill 951. Retrieved at: https://www.ncleg.gov/Sessions/2021/Bills/House/PDF/H951v5.pdf.

[4] HB 951 allows for delays for meeting the 70 percent reduction target under certain circumstances.

[5] North Carolina Utilities Commission (2021, October). Order Accepting Integrated Resource Plans, REPS and CPRE Program Plans with Conditions and Providing Future Direction for Future Planning. Docket No. E-100, Sub 165. Pp. 10-11. Retrieved at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=3142e686-6cb0-43e4-a71a-afb3e2518f94.

energy system.[6] The Duke Energy portfolios' shared dependence on these unproven resources are a meaningful source of operational and cost risks to ratepayers in Duke's proposals.

In addition to reviewing Duke's proposal in detail, Synapse conducted a resource planning analysis using EnCompass, the same capacity expansion and production cost modeling software that Duke Energy used to create their proposed Carbon Plan portfolios. Synapse's EnCompass analysis uses a comprehensive set of modeling inputs from Duke Energy as a baseline and makes several revisions to those model inputs to more accurately account for existing and projected future conditions. Synapse's EnCompass analysis then develops several scenarios that compare the effectiveness of different approaches:

- The *Duke Resources* scenario provides a baseline for comparison with Synapse's *Optimized* and *Regional Resources* scenarios. To provide an "apples-to-apples" comparison, this scenario uses the revised model inputs detailed in Table 3 below but maintains the resources that Duke Energy proposed in "Portfolio 1 – Alternate" portfolio.
- The *Optimized* scenario allows the EnCompass economic optimization algorithm to choose an economically optimal portfolio based on revised model inputs and expanded availability of zero-carbon resources. The resulting *Optimized* portfolio results in a broader range of resources—including energy efficiency, renewable energy, and battery storage—playing a greater role in meeting HB 951's carbon-reduction targets and the needs of Duke's ratepayers at a lower long-term cost.
- The *Regional Resources* scenario illuminates the potential economic benefit of access to Midwest wind resources. The resulting *Regional Resources* portfolio selects Midwest wind resources, in addition to energy efficiency, solar, and storage, and achieves more cost reductions while facilitating earlier retirement of some of Duke Energy's coal units.

All scenarios use the same set of core modeling inputs, allowing for a consistent comparison between the *Duke Resources* baseline and the Synapse scenarios. Portfolios developed in EnCompass meet all resource adequacy requirements and meet 100% of load in all hours modeled over the planning period.

This report describes in detail the development of Synapse's EnCompass scenarios (Section 2) and presents the results of Synapse's modeling analysis (Section 3). Section 4 explores the

[6] *See:* Princeton *Net Zero America* study (2020); MIT *Value of Inter-regional Coordination* study (2021); Electric Power Research Institute *Powering Decarbonization: Strategies for Net-Zero CO_2 emissions* (2021); and NREL *Seams* Study (2017).

EnCompass modeling conducted by Duke Energy in the development of their proposed Carbon Plan portfolios. The final section of the report provides Synapse's conclusions.

Economic optimization analysis can help to ensure that North Carolina pursues the resource pathway that is in the best interest of North Carolina ratepayers. Synapse's analysis shows that when costs are accounted for appropriately and cost-effective resources are allowed to compete, North Carolina can design a Carbon Plan that achieves HB 951's carbon-reduction requirements with lower costs and less risk than Duke's proposals.

2. SYNAPSE SCENARIO ANALYSIS

2.1. Duke Inputs and Revised Inputs

Duke Assumptions Adopted by Synapse

Synapse used the EnCompass database shared by Duke Energy as the foundation for their development of alternative resource portfolios. This scenario analysis maintains the vast majority of the data inputs and modeling parameters used by Duke in their own modeling, including the following key inputs:

- **System Transmission Topology**: Like Duke, Synapse modeled the DEC, DEP-East, and DEP-West areas individually, with transfer capability between areas. Consistent with the EnCompass analysis presented in Duke Energy's proposed Carbon Plan, the combined Duke Energy system is treated as an "island," separate from neighboring systems.
- **Reserve Margin:** Synapse's analysis maintained the same 17 percent winter reserve margin for the system, with a 15 percent reserve margin in the summer months. Portfolios developed by the EnCompass optimization must meet reserve margin requirements for every month and year in the analysis period.
- **Coal Prices:** Synapse used identical coal price projections to Duke's.
- **Carbon Constraint:** Synapse used the same carbon constraint as Duke Energy's Portfolio 1, which charts a linear mass-based carbon restraint from 2022 to 70 percent reduction from 2005 levels by 2030 and zero carbon, without the use of offsets, by 2050.
- **Ancillary Service Requirements:** Synapse used the same ancillary service requirements as Duke's analysis.
- **Gas Fuel Distribution and Cost Adders:** The Synapse analysis used the same gas fuel distribution infrastructure and cost adders as Duke's analysis.
- **Operating Characteristics of Generation Resources:** Except for the revisions shown in Table 3 below, Synapse adopted Duke Energy's specifications of the operational parameters of their existing conventional and renewable resources, as well as candidate resources. These parameters include, for example, heat rate, capability for co-firing, solar generation curves, and ancillary service capability.
- **Effective Load Carrying Capability:** This analysis assigned the same capacity value to conventional, energy-limited, and variable energy resources as Duke Energy does, using the same effective load carrying capability (ELCC) approach.

- **Transmission "Adders" for New Capacity:** Synapse analysis maintained the same approach to transmission investment that Duke Energy used in their EnCompass analysis by applying an additional cost per megawatt of new capacity to represent the carrying costs of additional transmission. Just as in Duke Energy's analysis, these additional transmission costs vary by resource.

Revisions to Duke Modeling Inputs

After evaluating and analyzing Duke Energy's modeling assumptions and EnCompass files, Synapse made several revisions to the modeling inputs used by Duke in developing their proposed Carbon Plan. These revised inputs provide a more accurate and realistic projection of future conditions. Table 3 provides a summary of these revisions. Additional details for these inputs can be found in Appendix A.

Table 3. Duke Inputs and Revised Inputs

Input	Duke Inputs	Revised Inputs
	System Settings	
Gas Prices	NYMEX futures for 5 years, blended into EIA 2021 AEO 'base' forecast[7]	NYMEX futures for 24 months, blended into EIA 2021 AEO 'base' forecast
Hydrogen Prices	Duke Energy internal forecast	Industry reference (BloombergNEF, Hydrogen Council)
	Existing Resources	
Coal Fixed Operations & Maintenance Costs	Internal Duke estimate	Forecast based on EIA's Sargent & Lundy fixed operations & maintenance study[8]
Gas Plant Depreciation	35 year book and operational lifetime[9]	Book life 20 years; Operational life 25 years
	Candidate Resources	
SMR Nuclear Capital Costs	Internal Duke estimate	EIA AEO 2022[10]
Gas New-Build Capital Costs	Internal Duke estimate	EIA AEO 2022
H2 New-Build Capital Costs	[BEGIN CONFIDENTIAL] [redacted]	[BEGIN CONFIDENTIAL] [redacted]

[7] Appendix E, p. 39.

[8] Sargent & Lundy (2018, May). Generating Unit Annual Capital and Life Extension Costs Analysis: Final Report on Modeling Aging-Related Capital and O&M Costs. Prepared for US Energy Information Administration. Retrieved at: https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

[9] Appendix E, p. 31.

[10] US Energy Information Administration (2022, March). Cost and Performance Characteristics of New Generating Technologies, *Annual Energy Outlook 2022*. Retrieved at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

	[redacted] [redacted] [END CONFIDENTIAL]	[redacted] [END CONFIDENTIAL]
H2 Retrofit Costs	Internal Duke estimate	25 percent of initial capital cost[12]
Solar Costs	Duke estimate from Guidehouse	NREL ATB 2022 – Moderate[13]
Solar-plus-Storage Costs	Duke estimate from Guidehouse	Mix of NREL ATB 2022 – Moderate (Solar) and Advanced (Storage)
Onshore Wind Costs	Duke estimate from Burns & McDonnell	NREL ATB 2022 – Moderate
Offshore Wind Costs	Duke estimate from Guidehouse	NREL ATB 2022 – Advanced
Storage Costs	Duke estimate from Guidehouse	NREL ATB 2022 – Advanced

To ensure consistency in comparing scenario results, Synapse used these revised inputs to calculate costs and economically optimize capital projects, retirements, and dispatch across all scenarios included as part of its analysis.

Synapse also adjusted some EnCompass settings compared to Duke Energy's configuration for its analysis. These are detailed, alongside other relevant issues that Synapse encountered in its EnCompass analysis, in Appendix B.

2.2. Baseline Portfolio for Scenario Analysis

Synapse's analysis includes a baseline scenario, which can be thought of as a "business as usual" counterfactual. Using a baseline in this way allows the comparison of resource additions and costs with a consistent set of underlying assumptions. Comparing results across analyses with different underlying assumptions can obscure why two outcomes might be different; this analysis uses a baseline scenario to avoid that issue.

Synapse identified as the baseline scenario the portfolio labeled by Duke Energy as "Portfolio 1 – Alternate" in their Carbon Plan proposal because it is designed to comply with the default HB 951 requirement of reaching 70 percent emissions reductions by 2030 and does not assume additional firm gas transmission capacity. Based on least-cost planning principles of avoiding major risks and on recent developments affecting Appalachian gas transmission, including the cancellation of the Atlantic Coast Pipeline and the uncertain future of the Mountain Valley

[11] Confidential Duke Energy Response to North Carolina Public Staff (NC Public Staff) Data Request (DR) 8-20.

[12] Öberg, S., Odenberger, M., & Johnsson, F. (2022). Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems. *International Journal of Hydrogen Energy*, 47(1), 624-644. Retrieved at: https://www.sciencedirect.com/science/article/pii/S0360319921039768.

[13] National Renewable Energy Laboratory (2022, June). Annual Technology Baseline. Retrieved at: https://atb.nrel.gov/.

Pipeline,[14] planning for a future without access to firm Appalachian gas represents a "no-regrets" approach.

2.3. Synapse Scenarios

Duke Resources Scenario

The *Duke Resources* scenario re-creates the set of resources proposed by Duke in "Portfolio 1 – Alternate."

Due to the extent of changes made in post-processing by Duke Energy in the development of their proposed scenarios and the analytical issues with these approaches described in Section 4, it was not feasible to re-create the same post-processing in Synapse's analysis. Instead, Synapse re-created precisely the same set of resources from Duke Energy's proposed "Portfolio 1 – Alternate" (P1-Alt). For this scenario, EnCompass was not allowed to economically optimize resource builds or retirements; instead, additions and retirements were all explicitly defined based on Duke Energy's proposed P1-Alt. This treatment places the set of resources to be either approved or denied by the NCUC in the context of a set of assumptions that better reflect actual and projected market conditions.

Optimized Scenario

The *Optimized* scenario allows the EnCompass model to select the set of resources and retirements that result in the most economic portfolio for North Carolina ratepayers under revised inputs and assumptions.

Duke Energy constrains deployment of several resources in their EnCompass modeling, which impede EnCompass's options for economic optimization in their proposed Carbon Plan. On the demand side, Duke Energy's baseline energy efficiency forecast assumes that incremental utility energy efficiency savings will decline from present levels to 1 percent of retail load (net of opt outs) over the long term. This treatment pre-emptively forecloses the ability for energy efficiency to cost-effectively compete with other resources or meet the system's energy needs. For the *Optimized* scenario, Synapse assumes that Duke Energy expands, rather than contracts, incremental energy efficiency savings to 1.5 percent of total retail load. For more details on Synapse's energy efficiency forecast, see Appendix A. Synapse also assumes that market trends and Duke Energy policies will continue to support the growth of distributed energy resources

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[14] In its October 21 Order on Duke Energy's 2020 IRPs, the NCUC stated that "Cancellation of the Atlantic Coast Pipeline and the present status of the Mountain Valley Pipeline extension both counsel the need for consideration of such possibility [of constrained transmission capacity." NCUC (2021), p. 7.

including rooftop solar, and the *Optimized* scenario adopts Duke Energy's high net energy metering (NEM) forecast.

Duke Energy's availability assumptions on the supply side constrain some resources, while allowing for the dramatic expansion of others. For example, Duke Energy allowed EnCompass to select a total of 10 GW of new nuclear capacity over the planning period, while constraining 4-hour batteries to 3.3 GW over the same period.[15] Synapse made several revisions to these inputs, consistent with reasonable expectations about future resource availability. These include a modest increase to solar availability to account for future procedural and policy innovations in interconnection, removing the aforementioned cap on 4-hour battery storage, and applying a more conservative approach to new nuclear deployment. Such assumptions about resource availability do not force EnCompass to choose these resources; instead, they provide more flexibility for the model to choose optimal resources. Synapse implemented changes to resource availability for the *Optimized* scenario as well as the *Regional Resources* scenario.

Table 4, below, shows the limitations that Duke placed on selected demand- and supply-side resources' eligibility to be selected by the EnCompass model, and compares those to the limitations that Synapse imposed in the Optimized Portfolio. The availability of each resource is expressed in capacity and/or number of units. Notably, incremental gas generation resources are not further constrained in the Synapse optimization compared to Duke Energy's assumptions around no further Appalachian firm gas transport. Additional details on these parameters can be found in Appendix A.

Table 4. Demand-Side Resources and Resource Availability Limits in Synapse *Optimized* Portfolio

INPUT	DUKE INPUTS	REVISED INPUTS
Energy Efficiency & DERs	Incremental savings at 1% of 'available' retail load; 'base' net metering forecast[16]	Ramping up to incremental savings of 1.5% of total retail load; 'high' net metering forecast
New Gas CCs and CTs	One 812 MW CC unit; no limits on CTs[17]	Same as Duke

[15] Synapse found that, for at least some portion of capacity expansion runs in Duke Energy's EnCompass database, 4-hour batteries were constrained to 3.3 GW (cf. the "HB951 CapEx-A2 (SMC2030-Seg8-ForceRet-NewZ4FT)" scenario and the "HB 951-Declining Bat ELCC-3.24.22 w/ BCPH2 Update" dataset). Counsel from Duke Energy verified that no confidential material has been divulged relating to this portion of the confidential EnCompass database.

[16] Appendix E, p. 16-17.

[17] Appendix E, p. 30-32.

SMR Deployment	Up to 20 units through 2050[18]	Up to 4 units through 2050
Economic Coal Retirement	Manually set by Duke Energy	Endogenous to EnCompass
Existing Gas Retirement	Not allowed to retire	Endogenous to EnCompass
Annual Solar Deployment Limits	Ramping from 750 MW in 2027; 1,800 MW in 2028 onwards[19]	1,200 MW in 2025; 1,800 MW 2026–2028; 2,300 MW in 2029 onwards
4-hour Storage Deployment Limits	System maximum 3.3 GW[20]	No maximum
Offshore Deployment Limit	1,600 MW through 2032, up to 4.8 GW through 2044[21]	8 GW by 2040; 10 GW by 2050

Regional Resources Scenario

In addition to the resources made available to the model in the *Optimized* scenario, the *Regional Resources* scenario allows the model to select power purchase agreements (PPAs) for Midwest wind, imported through the PJM Interconnection (PJM). These PPA resources were designed to imitate the Midwest wind resources identified in the North Carolina Transmission Planning Consortium's 2021 Public Policy Study.[22] Costs for these PPAs include the PJM border charge for firm point-to-point transmission service. Further details about these PPAs can be found in Appendix A.

[18] Appendix E, p. 33-36.

[19] Appendix E, p. 30.

[20] See footnote 15.

[21] Appendix E, p. 38.

[22] North Carolina Transmission Planning Consortium (2022, May). Report on the NCTPC 2021 Public Policy Study. Retrieved at: http://www.nctpc.org/nctpc/document/REF/2022-05-10/NCTPC_2021_Public_Policy_Study_Report_05_10_2022_Final_%20Draft.pdf.

3. SYNAPSE ENCOMPASS MODELING RESULTS

For each scenario, Synapse performed a two-step analysis in EnCompass. First, Synapse performed a capacity expansion analysis for each scenario, which identifies the pathway of new resources and retirements that the scenario will take 2022–2050. Next, Synapse performed a production cost analysis for each scenario, which simulates the operation of the identified resource pathway under more granular technical and temporal settings. The results of capacity expansion modeling are presented in Sections 3.1 and 3.2; results of production cost modeling are used for Sections 3.3 through 3.6.

3.1. Capacity Expansion Modeling Results

Figure 2 shows incremental resources and retirements chosen by capacity expansion modeling for each portfolio through 2030. In the *Duke Resources* scenario, a substantial amount of coal capacity is retired, and several additional gigawatts of gas capacity are accompanied by an increase in solar and storage capacity. The *Optimized* scenario retires the same amount of coal and focuses capacity deployment on solar plus storage. In the *Regional Resources* scenario, more of Duke's coal fleet can retire because of additional cost-effective Midwest wind resources.

Figure 2. Incremental Resource Builds and Retirements, 2022–2030

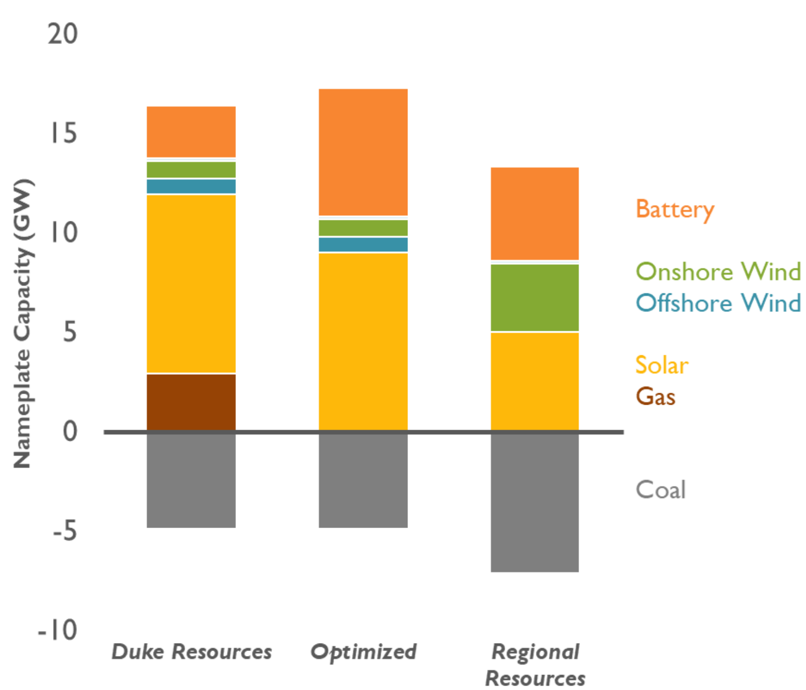


Figure 3 below shows the capacity expansion modeling results for the scenarios Synapse evaluated compared to the present capacity mix in 2022. By 2030, both the *Optimized* and *Regional Resources* scenarios show a notable decrease in carbon-emitting capacity, while the *Duke Resources* scenario's fossil capacity shifts incrementally toward gas from coal capacity. All scenarios contemplate an expansion of solar and energy storage resources, with the *Regional Resources* scenario selecting the most wind capacity (2.5 GW of onshore wind) of the scenarios over this period. Each 2030 portfolio was selected to achieve the 70 percent HB 951 carbon reduction requirement by 2030.

Figure 3. Capacity by Resource Type, 2022 and 2030, by Scenario

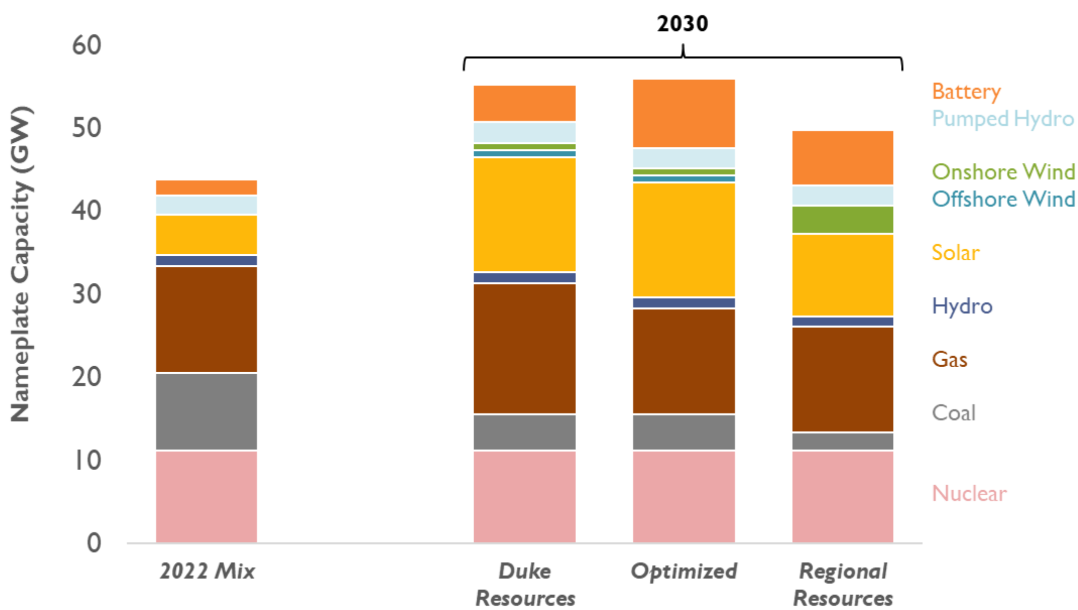


Figure 4 shows incremental resources and retirements between 2030 and 2050 for each scenario. Over this period, the *Duke Resources* scenario is noticeably different from the other scenarios, contemplating roughly 10 GW of incremental capacity of both new nuclear and hydrogen-burning resources. Both the *Optimized* and *Regional Resources* scenarios continue to build out solar and storage capacity. All resources retire the remainder of Duke's coal fleet over this period, and much of Duke Energy's gas capacity is also retired. The *Optimized* and *Regional Resources* scenarios retire an incremental 800 to 1,200 MW of gas capacity instead of retrofitting those units to burn 100% hydrogen.

Figure 4. Incremental Resource Builds and Retirements, 2030–2050

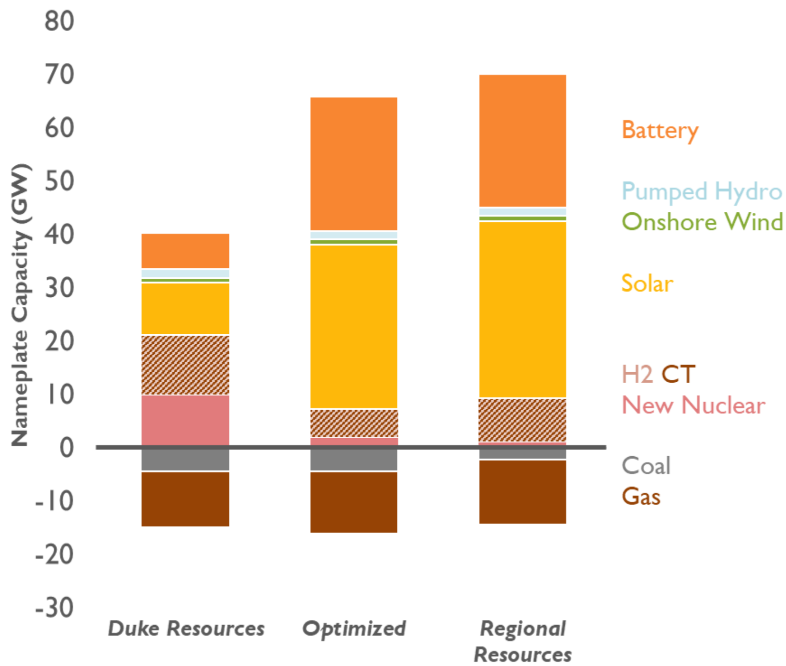
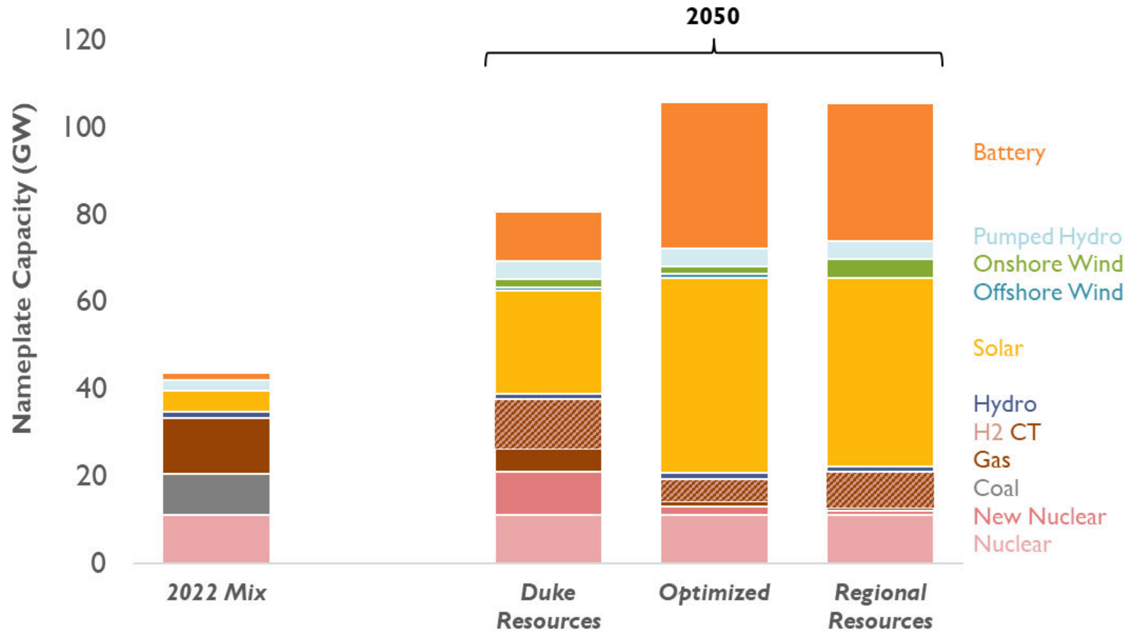


Figure 5 shows the total capacity for each portfolio in 2050 versus the 2022 capacity mix. In this case, differences in resource capacity are much clearer between the *Duke Resources* and the Synapse *Optimized* and *Regional Resources* portfolios. The *Duke Resources* portfolio includes substantial additions of new nuclear and hydrogen CTs, bringing 2050 nuclear, gas, and hydrogen capacity roughly equivalent to total generating capacity in 2022. In the *Optimized* and *Regional Resources* scenarios, EnCompass selects additional solar and storage resources instead of new nuclear and hydrogen. Load and capacity tables for these scenarios can be found in Appendix C.

Figure 5. Capacity by Resource Type, 2022 and 2050, by Scenario



3.2. Optimized Retirements

Retirement of Coal Units

Table 5 shows retirement years for Duke Energy's coal units by scenario. In the *Duke Resources* scenario, these retirement years are set manually, subject to the process described in Section 4; in the Synapse scenarios, these coal units are eligible to be economically retired by EnCompass.[23]

[23] Transmission must-run designations were left intact to ensure no adverse impacts to transmission conditions.

Table 5. Retirement Year for Selected Coal Units, by Scenario

Coal Unit	Capacity (MW)	Retirement Year		
		Duke Resources	*Optimized*	*Regional Resources*
Belews Creek 1-2	2,220	2036	2034	2030
Cliffside 5	546	2026	2023	2023
Marshall 1-2	760	2028	2026	2026
Marshall 3-4	1,318	2032	2032	2032
Mayo 1	713	2028	2028	2028
Roxboro 1-2	1,053	2028	2028	2028
Roxboro 3-4	1,400	2027	2027	2027

Source: Appendix E, p. 49.

Synapse's optimization finds that, even without building incremental gas CC or CT resources, accelerating retirement of coal units is still in the best interest of ratepayers. EnCompass modeling shows that, for instance, Duke could retire the Cliffside 5 unit in 2023 and continue to meet system reserve margin requirements and serve load, while delivering more cost-effective power. The Synapse scenarios also choose to retire the Belews Creek units either two or six years earlier and Marshall Units 1-2 two years earlier, reflecting the uneconomic nature of these units.

Retirement of Gas Units

Duke Energy's Carbon Plan assumes that, by 2047, hydrogen infrastructure and retrofit technology will allow for existing gas-fired units to be retrofitted to be capable of burning 100 percent hydrogen. [24] Duke Energy's scenarios assume that gas-fired resources with lives that extend past 2050 will each be retrofitted. In the Synapse scenarios, these units may be either retired or retrofitted for 100 percent hydrogen operations, depending on which choice is most economical. The status of each of these resources in 2050 by scenario is presented in Table 6.

[24] Appendix E, p. 23.

Table 6. 2050 Status of Gas-Fired Resources, by Scenario

Gas Unit	Capacity (MW)	2050 Status		
		Duke Resources	*Optimized*	*Regional Resources*
Asheville Combined Cycle	560	Retrofitted	Retrofitted	Retrofitted
W.S. Lee Combined Cycle	750	Retrofitted	Retired	Retired
Lincoln Combustion Turbine 17	402	Retrofitted	Retrofitted	Retired
Sutton Combustion Turbines	84 units (42 MW x 2 units)	Retrofitted	One unit retired	Retired

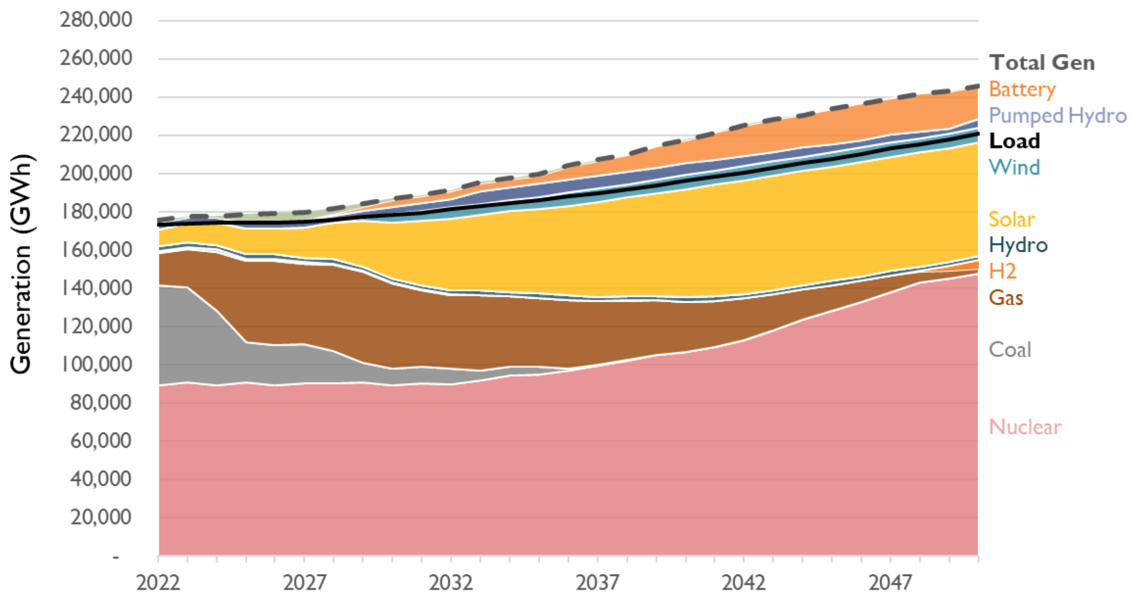
Source: Appendix E, p.23.

In both the *Optimized* and *Regional Resources* scenarios, some gas units are retired rather than being retrofitted for hydrogen use to avoid the incremental capital cost of hydrogen retrofitting. Retirement of these units reflects the additional risk of carbon-emitting generation: As carbon reduction requirements tighten, these units must either reduce generation or undergo substantial technical changes to maintain operation. Given the uncertainty around the feasibility and cost of zero-carbon retrofits, the assumption that such a retrofit is available is a substantial source of risk for prospective and existing gas units.

3.3. Production Cost Modeling Results

Figure 6 shows annual generation over time for the *Duke Resources* scenario, as optimized by EnCompass's production cost modeling function. The most striking feature of *Duke Resources'* generation curve is the substantial increase in total nuclear generation over time, producing 65 percent more generation in 2050 than the technology did in 2022. In the later years, solar and storage grow to serve most of the load not already served by nuclear. Gas share of total generation peaks at 30 percent in 2029.

Figure 6. Annual Generation Over Time, *Duke Resources* Scenario



Annual generation by technology for the *Optimized* scenario is provided in Figure 7. Nuclear generation remains constant in this scenario, generating roughly as much in 2022 as it does in 2050. Solar and energy storage grow to meet remaining load over the period, with renewable generation representing 62 percent of total generation in 2050. In both scenarios, gas and hydrogen generation combine to serve 3% of total load in 2050.

Figure 7. Annual Generation over Time, *Optimized* Scenario

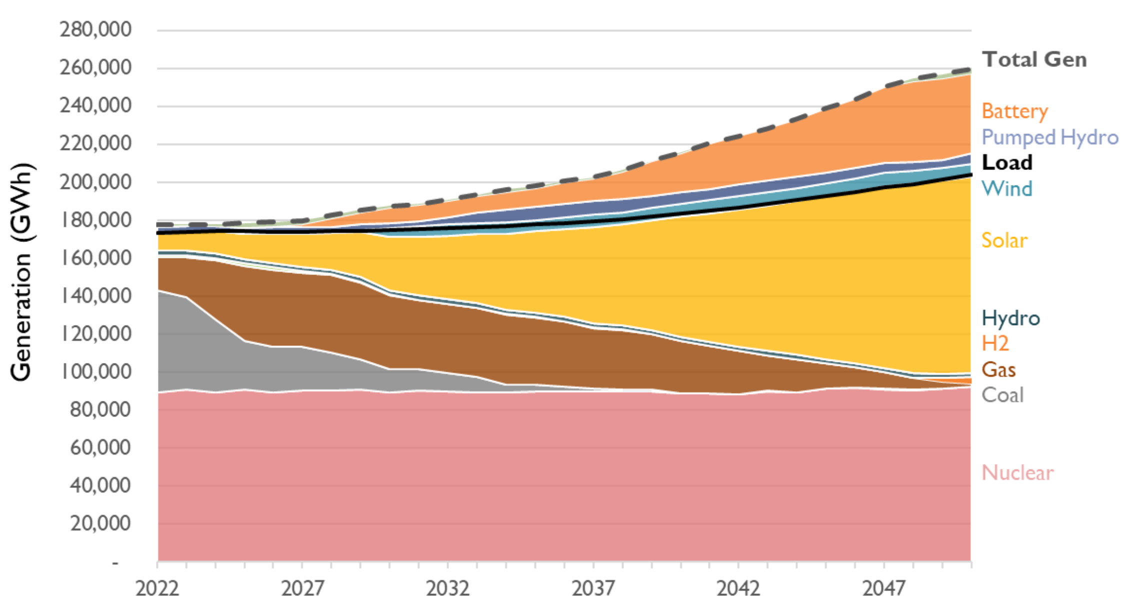
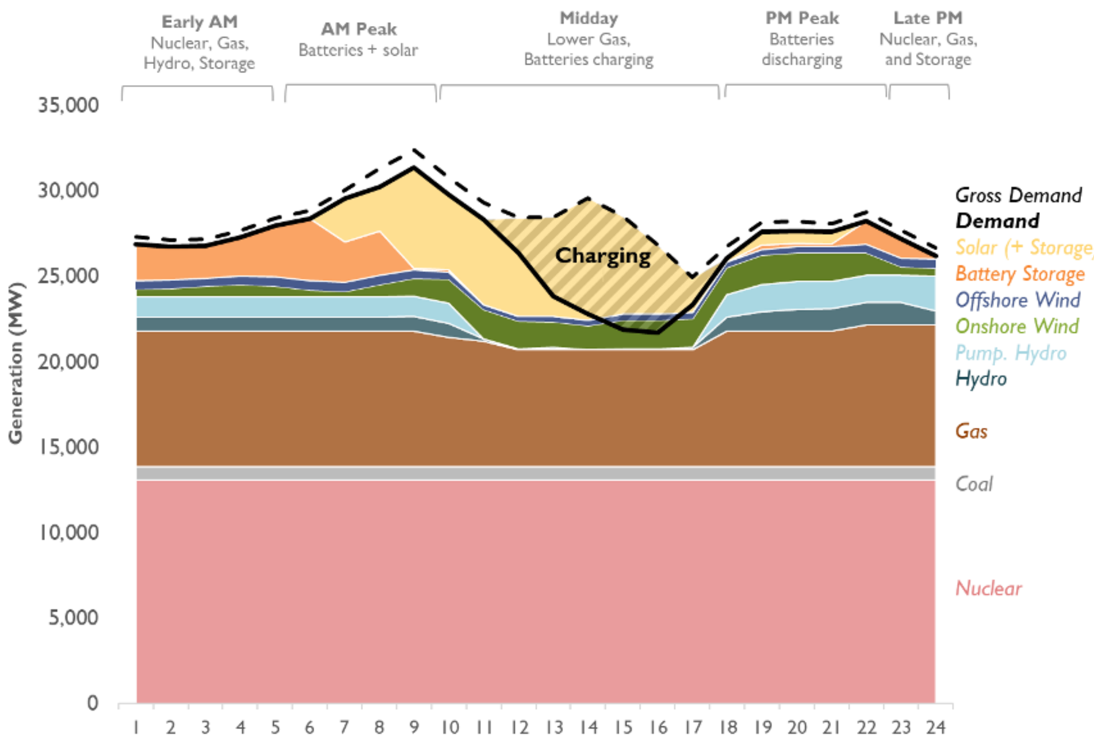


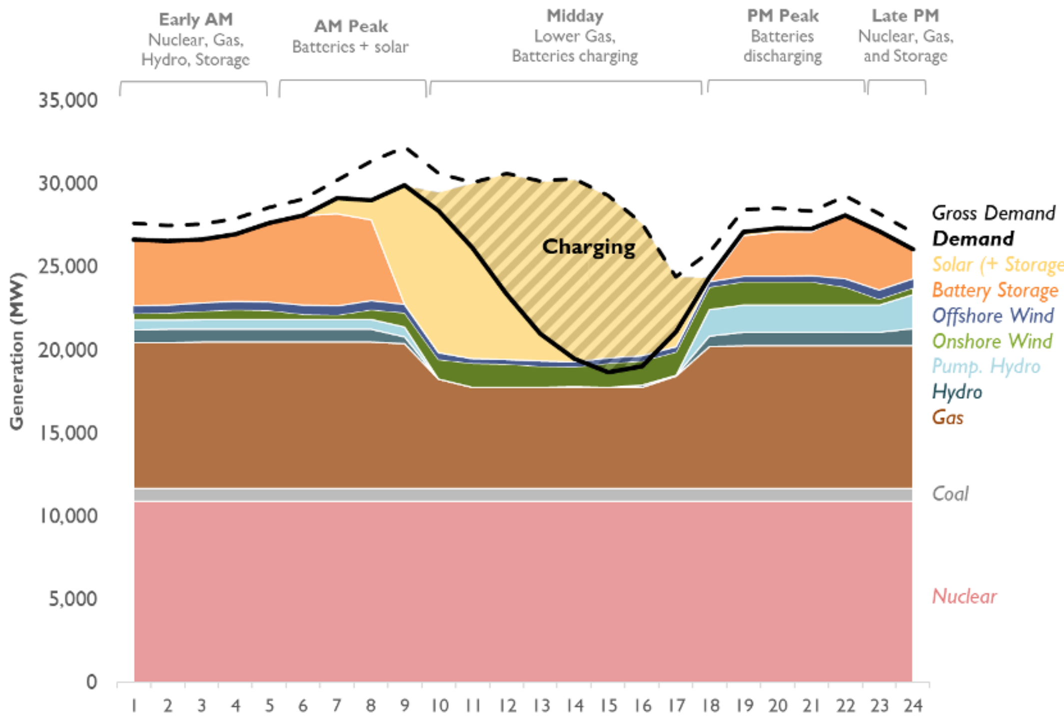
Figure 8 and Figure 9, below, show the mix of energy technologies that serve load during winter peaks in 2040 in the *Duke Resources* and *Optimized* scenarios. These graphs provide additional detail on how the system could dispatch its available resources to meet load under high-stress conditions.

Figure 8. Winter Peak Generation by Technology, January 2040, *Duke Resources* Scenario



The black line represents net demand served by generation resources, with shaded areas above the line representing charging for battery storage resources. The dotted "gross demand" line shows the impact of both battery charging and utility energy efficiency on load. In the *Duke Resources* scenario, the system has roughly 22 GW of nuclear, gas, and coal resources (although the lone coal unit, Cliffside 6, is running on 100-percent gas). The *Duke Resources* scenario selects considerable amounts of solar-plus-storage resources, which are able to shift dispatch to earlier in the day to meet the winter morning peak. In the middle of the day, solar generation allows higher-cost resources to ramp down and charges battery storage. Overnight, hydro, gas, and storage resources ramp up to meet demand.

Figure 9. Winter Peak Generation by Technology, January 2040, *Optimized* Scenario



In the *Optimized* scenario shown in Figure 9, the relative proportions of gas and nuclear are lower while the proportions of solar and storage are higher. This graph also shows the impact of investment in increased energy efficiency over time (2022–2040), as cumulative EE savings push morning net peak load down by roughly 2 GW. As before, battery storage is used to meet load overnight and charged during mid-day, when low-cost solar generation is available.

Both of these graphs demonstrate the basic dynamics of a grid with increased penetration of renewable energy resources. Renewables provide plentiful, low-cost power, and flexible resources like storage and pumped hydro are able to charge during high-solar periods and discharge when needed. Effectively, these storage resources shift low-cost renewable energy around to meet load. Compared with the *Duke Resources* scenario in Figure 8, the *Optimized* scenario in Figure 9 shows the incremental benefit of additional energy efficiency, which drives down load in all hours, and the flexibility of battery storage, which is able to support generation around the clock.

3.4. Carbon Dioxide Emissions

Consistent with Duke Energy's production cost modeling, Synapse did not include any per-ton carbon costs in its base production cost modeling. Nevertheless, the portfolios generally trace the linear carbon target to 70 percent reduction by 2030 and zero carbon by 2050. Synapse's analysis finds that, without per-ton pricing of carbon emissions, the *Duke Resources* scenario does not comply with the HB951 70 percent reduction requirement in 2030. Table 7 shows carbon emissions in 2022, 2030, and 2050 across scenarios.

Table 7. Carbon Emissions by Scenario

Carbon Emissions (Million Tons)	*HB 951 Carbon Requirement*	*Duke Resources*	*Optimized*	*Regional Resources*
2022	*None*	59.4	59.4	59.4
2030	24.9	25.2	24.8	24.9
2050	0	0	0	0

3.5. Net Present Revenue Requirements of Synapse Portfolios

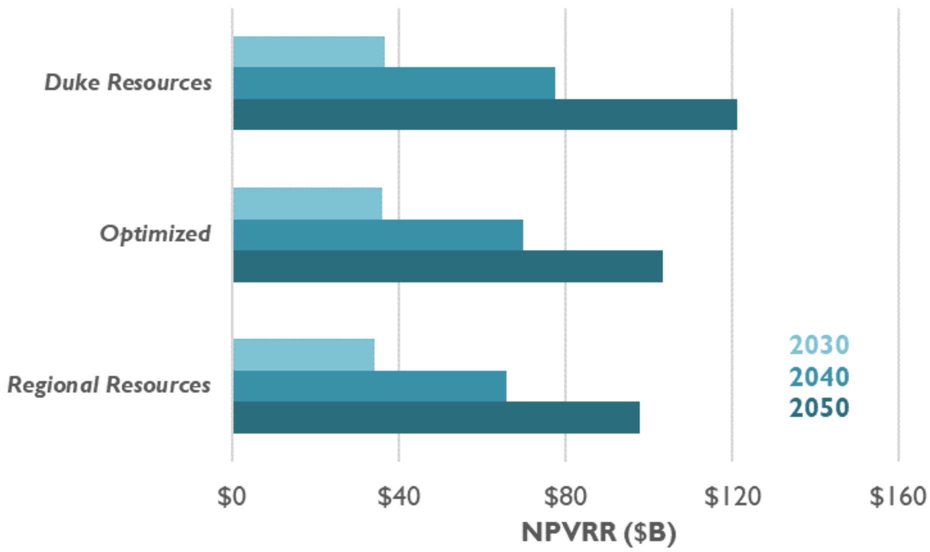
Table 8 shows the net present revenue requirement (NPVRR), or long-term system cost to ratepayers, for each portfolio over time, discounted by Duke Energy's weighted average cost of capital. Each of the Synapse portfolios has a lower NPVRR than the *Duke Resources* portfolio, with $8 to 12 billion in savings to ratepayers in 2030 and $18 to 23 billion in 2050. These savings are principally driven by avoiding the high capital expenditures associated with Duke Energy's buildout of nuclear reactors, gas units, and hydrogen units in the *Duke Resources* case and the higher energy efficiency forecast that results in less total load to be served by supply-side resources. Again, the *Regional Resources* portfolio stands out for its sizable cost reductions even compared to the *Optimized* scenario, with savings of $5 billion compared to the *Optimized* scenario and $23 billion compared to the *Duke Resources* scenario on a net present basis through 2050. This result demonstrates the economic benefit of accessing cost-effective, zero-carbon power from outside the Duke Energy service territory.

Table 8. Net Present Value Revenue Requirement over Time by Scenario

Results (2022-2050)	*Duke Resources*	*Optimized*	*Regional Resources*
2030 NPVRR ($B)	$36.7	$36.0	$34.3
2040 NPVRR ($B)	$77.7	$69.8	$65.8
2050 NPVRR ($B)	$121.2	$103.5	$98.1

Figure 10 shows the revenue requirement by scenario for 2030, 2040, and 2050.

Figure 10. Revenue Requirement by Scenario



In general, the revenue requirement produced by EnCompass is not designed to be comprehensive or directly comparable to the entire set of costs incurred by a utility as presented in a rate case. Instead, the NPVRR reported by EnCompass represents the portion of total revenue requirement that goes toward construction and operation of generation resources, as well as incremental transmission. Synapse added incremental energy efficiency costs to both scenarios to ensure consistent treatment of demand-side resources.

3.6. Sensitivity Analysis

Synapse ran several sensitivities using EnCompass's production cost modeling function to evaluate the impact of other potential future conditions on the different portfolios.

RGGI Sensitivity

Synapse included a sensitivity in which the Carolinas joined the Regional Greenhouse Gas Initiative (RGGI) to assess the impact that RGGI would have on Duke system emissions.[25] This sensitivity is implemented by applying a per-ton price to carbon emissions based on the projected RGGI-wide clearing price. Compared to Duke Energy's carbon risk sensitivities, which

[25] Synapse used an annual RGGI allowance cost forecast from the Horizons Energy National Database's Fall 2021 release.

start at $5 per ton and increase by up to $10 annually, this RGGI forecast adds a per-ton cost to carbon emissions in the range of $10 to $50 per ton of CO_2.

The RGGI sensitivity impacted generation mix and projected emissions for the *Duke Resources* scenario. The incentive provided by RGGI shifted marginal generation from coal to gas resources, resulting in a decrease in coal generation of 10,000 GWh. Through 2035, inclusion of RGGI resulted in reductions of emissions of 0.2 to 1.1 million tons annually. This amount of reduction was sufficient to reduce the *Duke Resources* scenario's emissions to reach the HB 951 70 percent reduction requirement in 2030.

Per-ton costs on carbon generate RGGI revenues, which are deployed in a variety of ways across RGGI states to the benefit of ratepayers.[26] In the *Duke Resources* case, RGGI revenues reach $2 billion on a net-present basis by 2030 and $3.7 billion by 2050. These revenues could pay for the entirety of *Duke Resources'* utility energy efficiency expenditures over that period.

High Gas Price Sensitivity

Synapse modeled the *Duke Resources* and *Optimized* scenarios with a higher gas price forecast based on Duke Energy's high gas price forecast and Synapse's hydrogen price forecast. For these sensitivities, Synapse found an increase in costs in both scenarios to reflect the higher cost to run Duke's existing gas resources. Table 9 shows the revenue requirement for high gas price sensitivities for the *Duke Resources* and *Optimized* portfolios.

Table 9. Revenue Requirement for High Gas Sensitivities

Results (2022-2050)	*Duke Resources*	*Duke Resources – High Gas Price*	*Optimized*	*Optimized – High Gas Price*
2030 NPVRR ($B)	$36.7	$39.8	$36.0	$38.7
2040 NPVRR ($B)	$77.7	$84.2	$69.8	$76.0
2050 NPVRR ($B)	$121.2	$128.7	$103.5	$110.7

Lower Energy Efficiency Sensitivity

To ensure that the *Optimized* portfolio would remain cost-effective even with a lower level of energy efficiency, Synapse conducted a sensitivity that assumed energy efficiency savings

[26] Regional Greenhouse Gas Initiative, Inc. (2022). The Investment of RGGI Proceeds in 2020. Retrieved at: https://www.rggi.org/sites/default/files/Uploads/Proceeds/RGGI_Proceeds_Report_2020.pdf.

equivalent to 1 percent, rather than 1.5 percent, of total retail load. The resulting revenue requirements for this lower-EE sensitivity are shown in Table 10.

Table 10. Net Present Revenue Requirement over Time, Energy Efficiency Sensitivities

Results (2022-2050)	*Optimized*	*Optimized – Low EE*
2030 NPVRR ($B)	$36.0	$36.0
2040 NPVRR ($B)	$69.8	$71.0
2050 NPVRR ($B)	$103.5	$106.4

Increased energy efficiency investment in the short term keeps the *Optimized* and *Optimized – Low EE* scenarios at the same NPVRR through 2030, but those investments pay off in the long term where they result in a reduction of revenue requirement through 2050 of $2.9 billion. In terms of resources, the *Optimized – Low EE* sensitivity builds substantially more resources to serve additional load compared to the *Optimized* scenario: Overall, the *Low EE* case builds an additional 752 MW of gas combustion turbines, 3.8 GW of solar, and 2.6 GW of energy storage. Savings over time in the *Optimized* case demonstrates that investment in energy efficiency is a more cost-effective choice than selecting additional supply-side resources.

4. Duke's EnCompass Analysis and Post-Processing Methodology

Duke Energy used the EnCompass capacity expansion and production cost modeling software as the starting point for their resource planning analysis. When used appropriately, economic optimization software like EnCompass can identify the resource pathway that delivers power at least cost. When model inputs do not accurately represent current and future conditions, or when the user overrides resource selections identified by EnCompass with manual post-processing changes, however, the analytical power of EnCompass software is diminished. As a result, selected portfolios are not likely to be most cost-effective for ratepayers.

Rather than providing a wide selection of resource options and allowing EnCompass economic optimization to select an optimal portfolio, Duke Energy's methodology constrained resource choices and, over several analytical steps, directly over-rode selections made by EnCompass by "forcing in" additional resources or making substitutions. These actions undermine the ability for portfolios to meet HB 951's requirements that portfolios deliver carbon reductions at least cost. The proposed Carbon Plan filing details the alterations Duke Energy made in developing their proposed portfolios:

- **Coal Retirement.** Duke Energy used a combination of EnCompass analysis and additional, manual delays to identify the retirement years for coal units proposed in the Carbon Plan.
- **Replacement of Battery Storage with Combustion Turbines.** Duke Energy manually replaced battery storage selected by the economic optimization model with additional gas-fired CTs.
- **Resource Adequacy and Reliability Verification.** Duke Energy added additional CTs based on a high-level assessment of continued portfolio reliability metrics.

4.1. Duke's Coal Retirement Methodology

In its order reviewing Duke Energy's 2020 IRPs, the NCUC directed Duke Energy to further analyze the retirement timing of Duke Energy' coal fleet.[27] Duke Energy conducted their previous coal retirement analysis without a capacity expansion and production cost model like EnCompass, and instead used a non-economic "ranking" of coal units and an imprecise estimate of the value of the legacy coal fleet's capacity and energy.[28] In contrast, using economic optimization software to dynamically select coal retirement dates allows the retirement of coal resources to be timed optimally with the addition of new resources and re-dispatch of existing resources, resulting in lower total costs across the entire portfolio. In terms of coal unit economics, endogenous retirement analysis that allow the portfolio as a whole to adapt and evolve provides a much more precise analytical tool than discrete analyses that must approximate the value of energy and capacity to the system.

In developing their proposed Carbon Plan, Duke Energy did allow EnCompass to co-optimize coal retirement timing with new resource construction and resource dispatch as a part of their overall coal retirement analysis. Duke Energy's subsequent manual changes to retirement dates, however, functionally over-rode the conclusions of the endogenous retirement analysis conducted in EnCompass.

[27] *See:* North Carolina Utilities Commission (2021, October). Order Accepting Integrated Resource Plans, REPS and CPRE Program Plans with Conditions and Providing Further Direction for Future Planning. Docket No. E-100 Sub 165. P. 10. Retrieved at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=3142e686-6cb0-43e4-a71a-afb3e2518f94.

[28] *Ibid.*

Duke Energy's manual adjustments created a difference of up to six years between the endogenously-identified least-cost retirement timeline selected by Duke Energy's original EnCompass results and the proposed retirement timeline Duke Energy ultimately chose.[29] Compared to the "Earliest Practicable" retirement years identified in Duke Energy's 2020 Integrated Resources Plans, this difference grows to eight years. Synapse's EnCompass analysis projects that keeping these coal units online to meet Duke Energy's proposed retirement dates (rather than those selected by EnCompass) would cost ratepayers an additional $1.4 billion, even before accounting for fuel costs or variable operation and maintenance costs, which would further increase total costs to ratepayers. Delaying these retirements also diminishes the value of securitizing these assets.

Table D-1, in Confidential Appendix D, shows coal unit retirement years as selected by EnCompass (labeled as "2022 Most Economic Retirement Year" in the table) versus those chosen by Duke Energy (labeled as "2022 Proposed Retirement Year"). The table also includes earliest practicable coal retirement dates from Duke Energy's 2020 Integrated Resources Plans as "2020 Earliest Practicable Retirement Year."

Duke Energy justifies their proposed delays beyond the economically optimal coal retirement dates by noting the need to consider transmission constraints and replacement resources when retiring legacy coal units. However, Duke's proposed Carbon Plan does not provide enough information to systematically understand the nature of these constraints, identify potential solutions, and develop resources to facilitate coal retirement. [30] Duke Energy's Appendix P states that the Belews Creek units "will continue to operate into the 2030s," for example, even though Duke Energy's 2020 Integrated Resource Plans identified 2029 as the earliest practicable retirement date for these units.[31] To the extent that local transmission or generation resources are needed to retire these units, Duke Energy could identify and accelerate development of these resources, including using transparent, all-source procurement for replacement generation resources, to meet economical retirement dates.[32] Instead, Duke Energy's methodology results in continued operations of uneconomical coal plants to ratepayers' detriment.

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[29] Confidential Duke Energy response to North Carolina Sustainable Energy Association and Southern Alliance for Clean Energy (NCSEA-SACE) DR 3-39(L). Counsel from Duke Energy verified that no confidential material has been divulged relating to this confidential response to data request.

[30] Appendix E, p. 48.

[31] Duke Energy Carbon Plan Appendix P (Appendix P), p. 15 and Duke Energy Carolina Integrated Resource Plan 2020 Biennial Report, p. 175.

[32] For an example of all-source procurement used for coal unit retirement, see Northern Indiana Public Service Company's 2018 Integrated Resource Plan.

4.2. Duke's Manual Replacement of Battery Storage with CTs

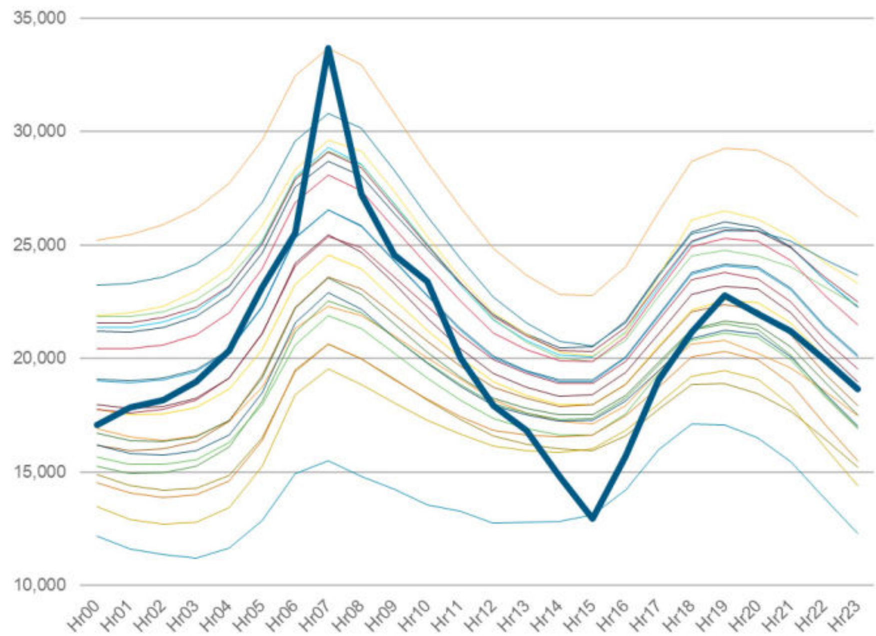
After the coal retirement analysis, Duke Energy completed a capacity expansion and production cost modeling exercise with Duke's chosen coal retirement dates "locked in." Next, Duke Energy replaced battery storage identified by EnCompass as economically optimal with additional gas CTs. As a result of this process, Duke Energy manually removed between 1.6 and 2 GW of battery storage that had been selected by the EnCompass model from their portfolios and added between 1.5 and 1.9 GW of natural gas CTs.[33] This represents a substantial portion of the total new natural gas-burning CTs built over the planning period in Duke Energy's proposed portfolios: In "Portfolio 1 – Alternate," CTs added during this step represent five of the seven total natural gas-burning CTs added (or over 70 percent of total gas CT capacity added).[34]

Duke Energy's justification for the manual replacement of battery storage selected by EnCompass with gas CT capacity is that the "typical day" load construct used by EnCompass to ensure that resource portfolios can serve a wide variety of conditions favors battery storage technologies that can serve a narrow 'peak' over CTs that can provide capacity over a longer period. Figure 2 provides an example of this "typical day" load shape.

[33] Appendix E, p. 60.

[34] Appendix E, p. 60.

Figure 11. Capacity Expansion "Typical Day" Load Shape, Example



Source: Appendix E, p. 58. Each line on the above graph represents total load over time for an individual day. The bold line, representing the "typical day" load shape, is designed to capture the wide range of potential load conditions in a single day.

This justification relies on an inaccurate characterization of Duke Energy's capacity expansion modeling process, applies a remedy that does not treat all resources consistently, and ultimately creates additional risk of stranded generation assets and non-attainment of carbon reduction requirements.

First, while it is true that the Duke Energy's capacity expansion runs use the "Typical Day" load construct, Duke also applies additional simplifications to system load for these runs. Duke Energy's capacity expansion runs condense each 24-hour day into six 4-hour intervals.[35] This interval represents the smallest unit of time available to EnCompass during one of Duke's modeling runs: load is constant over the course of a single interval, and dispatch choices, for example, cannot change during an interval. Therefore, at a minimum, any "peak" observed in the capacity expansion would need to be at least four hours in duration. Given this additional transformation, "Typical Day" daily peak loads are not, in fact, modeled as "needle peaks."

[35] *See* "HB951 EnCompass Scenarios and Datasets - Master Import File - 5.13.22.xlsx." from Duke Energy's May 16, 2022 EnCompass data share. Counsel from Duke Energy verified that no confidential material has been divulged relating to this information from the confidential EnCompass database.

Second, Duke Energy's proposed remedy to this solution contemplates substituting only one resource type—gas-fired CTs—for one other resource type—battery storage. This approach runs directly counter to the resource planning principle of allowing all resources to compete and choosing the most economical portfolio. Solar generation, for example, would generate a substantial portion of its energy between Hour 9 and Hour 15 on Figure 11. Some combination of solar and other resources, including longer-duration storage, might have even more cost-effectively addressed load, but Duke Energy did not consider other configurations of resources beyond additional CTs. Duke Energy did not provide the PVRR value of this replacement in their proposed Carbon Plan, nor did it cite any specific reliability standard in justifying these replacements.[36]

Finally, by 'forcing in' carbon emitting resources outside of capacity expansion modeling during this process, Duke Energy bypassed the model's evaluation of HB 951 's carbon requirements compliance for the additional gas turbines. Duke Energy is unable to test whether these resources endanger compliance with carbon requirements or determine whether these resources are cost-effective when planning for a de-carbonized grid. Effectively, these resource replacements represent a selective application of HB 951's emissions requirements: applicable to most resources selected by EnCompass, but not applicable to resource additions and substitutions after the fact. Duke Energy's finding that some of their portfolios are unable to meet carbon reduction requirements in subsequent production cost modeling could be a reflection of these *ex post* resource decisions.[37]

4.3. Additional Manual Resource Additions

Portfolio Reliability and 2050 CO_2 Reduction Verification

In this step, Duke Energy added between 900 and 1,100 megawatts (MW), varying by portfolio, of additional "Reliability and CO2 Reduction Requirement" resources to their portfolios to address "resource insufficiencies" identified during production cost modeling.[38]. Although the technology is not explicitly identified in their proposed Carbon Plan, Duke Energy has confirmed that the contemplated technology is additional SMRs.[39] As with other decisions described above, this decision undermines the analytical power of EnCompass's economic optimization. If Duke Energy desired additional reliability from the system over a given time period, it could revise system requirements in EnCompass such as the reserve margin, and the economic

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[36] Appendix E, p. 57-59.

[37] Appendix E, p. 89.

[38] Appendix E, p. 61.

[39] Duke Energy response to NCSEA-SACE 3-43.

optimization will select the most cost-effective resource to meet those needs, while co-optimizing against carbon and cost-effectiveness requirements. Manually "forcing in" additional resources is not consistent with an economically optimal approach.

Portfolio Loss of Load Expectation (LOLE) and Resource Adequacy Validation

Finally, Duke Energy used extrapolated values from their 2020 Resource Adequacy study to characterize future reliability for their Carbon Plan proposed portfolios and add additional gas CTs if these portfolios did not reach a future reliability threshold constructed from the results of those studies.[40]

To summarize Duke Energy's methodology for this process, Duke Energy re-ran the DEC-DEP "Combined" scenario from their 2020 Resource Adequacy Studies with and without assistance from neighboring utility systems (an "interconnected" and an "islanded" case). Duke Energy converted the net benefit from neighboring utility systems in these model runs into a static "interconnection benefit" that could allow a system to achieve resource adequacy targets, even if the system might not meet those targets in an "islanded" case. Duke Energy performed additional SERVM runs on the proposed portfolios to determine if the system's own resources plus the static "interconnection benefit" would be sufficient to meet an established loss of load expectation (LOLE) threshold. If LOLE for any of the portfolios in 2030 or 2035 exceeded this threshold in SERVM analysis, Duke Energy added additional CTs to that portfolio.

This treatment represents a meaningful departure from the typical use of resource adequacy studies in resource planning, and Duke Energy acknowledges that it is not aware of any analysis or Commission decision that has contemplated, deployed, or approved this practice.[41] Typically, resource adequacy studies are used to develop a capacity reserve margin that can ensure reasonably reliable service over the planning period; each of these portfolios was designed to meet the 17 percent planning reserve margin developed by the 2020 Resource Adequacy Studies. Given the expected change in generation portfolios between now and 2030 and 2035, extrapolating LOLE results from today to those future dates is not appropriate. Further, this practice embeds an assumption that additional regional capacity coordination will not develop

[40] *See:* Duke Energy Carbon Plan Attachment I – DEC Resource Adequacy Study; and Duke Energy Carbon Plan Attachment II - DEP Resource Adequacy Study.

[41] Confidential Duke Energy Response to NCSEA-SACE DR 3-45. Counsel from Duke Energy verified that no confidential material has been divulged relating to this confidential response to data request.

in the intervening years, despite leading research showing that such coordination is cost-effective[42] and existing state and federal efforts to facilitate regional coordination.[43]

Similarly to the previous "Portfolio Reliability and 2050 CO_2 Reduction Verification" step, Duke Energy's decision to insert resources into the portfolio manually, rather than adjusting the reliability parameters in EnCompass, effectively circumvents the economic optimization process. Future reliability concerns could be addressed, for example, by increasing the reserve margin in future years; once these changes are set, EnCompass could select the most cost-effective resource given these updated reliability needs and existing carbon constraints. By contrast, the choice to manually insert CTs does not reflect planning best practices and is not as likely to achieve the most cost-effective outcomes for North Carolina ratepayers.

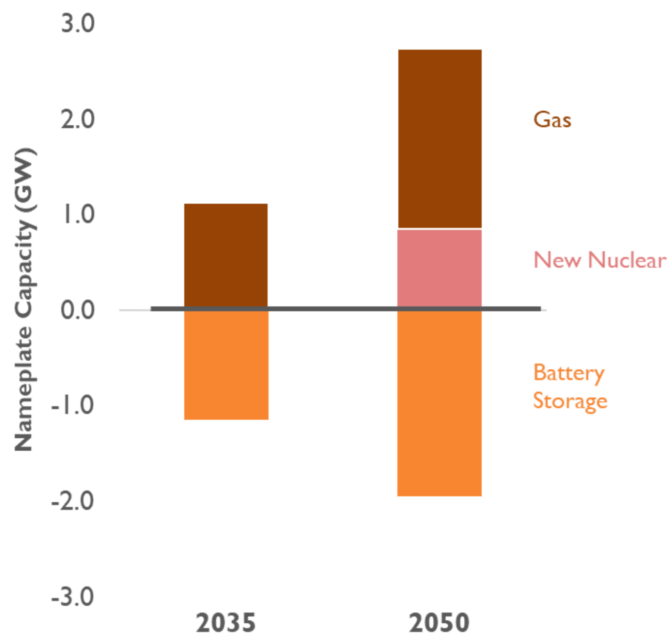
4.4. Cumulative Effect of Duke's Manual Portfolio Changes

Duke's manual revisions had a sizable impact on the system capacity mix for Duke Energy's portfolios. Figure 12 below shows the cumulative impact of manual revisions on Portfolio 1.

[42] *See:* Brown, P. R., & Botterud, A. (2021). The value of inter-regional coordination and transmission in decarbonizing the US electricity system. Joule, 5(1), 115-134.

[43] *See:* US Department of Energy (2022, January). Building a Better Grid Initiative to Upgrade and Expand the Nation's Electric Transmission Grid to Support Resilience, Reliability, and Decarbonization. Retrieved at: https://www.energy.gov/sites/default/files/2022-01/Transmission%20NOI%20final%20for%20web_1.pdf; *and* Sweeney, D. (2020, January). "SC lawmakers introduce joint resolution to study electricity market reform." S&P Global. Retrieved at: https://www.spglobal.com/marketintelligence/en/news-insights/trending/k_4edpusx8hnvqivnsh-7q2.

Figure 12. Manual Changes to Duke Energy Portfolios through 2035 and 2050, Duke Energy Portfolio 1



Source: Duke Energy Response to NC Public Staff DR 9-10.

For context, the total nameplate capacity of Duke Energy's generation fleet across all resources today is roughly 40 GW; the 5 GW net change in 2050 represents roughly one eighth of Duke Energy's total nameplate capacity today. This represents a substantial deviation from the portfolio selected by EnCompass's economic optimization software. As stated above, these resources were not subject to the declining HB 951 carbon mass cap that guided EnCompass resource selection in Duke Energy's initial cost runs. Given that Duke Energy adds gas and removes energy storage in the first half of the planning period, this might help to explain why some of Duke Energy's portfolios fail to meet carbon reduction requirements by their intended dates.[44]

4.5. Review of Duke Energy's Proposed Carbon Plan Portfolios

Based on Duke Energy's EnCompass analysis and their post-processing manual revisions described above, Duke Energy proposed eight distinct but similar portfolios in their proposed Carbon Plan. The primary distinguishing feature across portfolios is the year in which Duke achieves the 2030 carbon reduction requirement of 70 percent. The "Portfolio 1" (P1) portfolios

[44] See: Appendix E, p. 89.

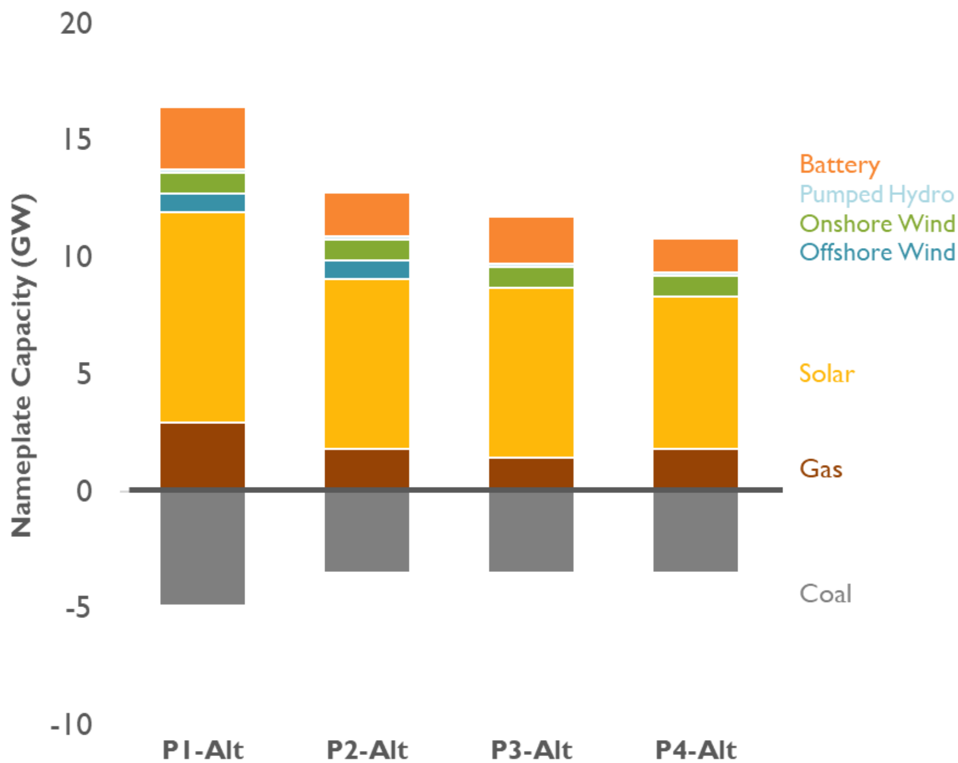
achieve the 70 percent reduction requirement in 2030. “Portfolio 2” and “Portfolio 3” (P2 and P3) achieve the interim reduction requirement by 2032, while deploying offshore wind and SMRs, respectively. “Porfolio 4” (P4) portfolios deploy both offshore wind and SMRs in the first half of the 2022–2050 planning period and meet the 70 percent reduction requirement in 2034.

As directed by the NCUC, each proposed portfolio includes a case that assumes additional firm Appalachian gas transport capacity is not available;[45] Duke Energy identifies these portfolios as the “alternate” portfolios. In practice, reduced access to firm gas transportation reduces the total number of combined-cycle (CC) units deployed and results in higher delivery costs for gas fuel. This section will compare the scenarios that do not assume additional firm capacity, but the “alternate” portfolios are broadly indicative of resource trajectories for the scenarios without additional firm capacity.

Figure 13, below, shows incremental capacity builds and retirements 2022-2030 across scenarios.

[45] North Carolina Utilities Commission (2021, October). Order Accepting Integrated Resource Plans, REPS and CPRE Program Plans with Conditions and Providing Further Direction for Future Planning. Docket No. E-100 Sub 165. P. 10. Retrieved at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=3142e686-6cb0-43e4-a71a-afb3e2518f94.

Figure 13. Incremental Resource Builds and Retirements, 2022–2030



P1-Alt, P2-Alt, P3-Alt, and P4-Alt designate the "alternate" portfolios that do not assume additional firm Appalachian gas transport capacity for Portfolios 1 through 4, respectively.

The four portfolios follow a similar trajectory, 2022–2030: Substantial investment in solar, while retiring a portion of Duke's coal fleet and investing in incremental gas-fired resources. Duke's scenarios also build out the first on- and off-shore wind projects and invest in several GW of energy storage.

Although the timing of the 70 percent reduction is different by portfolio (2030 for P1-Alt, 2032 for P2-Alt and P3-Alt, and 2034 for P4-Alt), there are few substantial differences in the portfolios through 2030. Figure 14 shows total capacity by resource type for each portfolio in 2022 versus 2030.

Figure 14. Capacity by Resource Type, 2022 and 2030, by Scenario

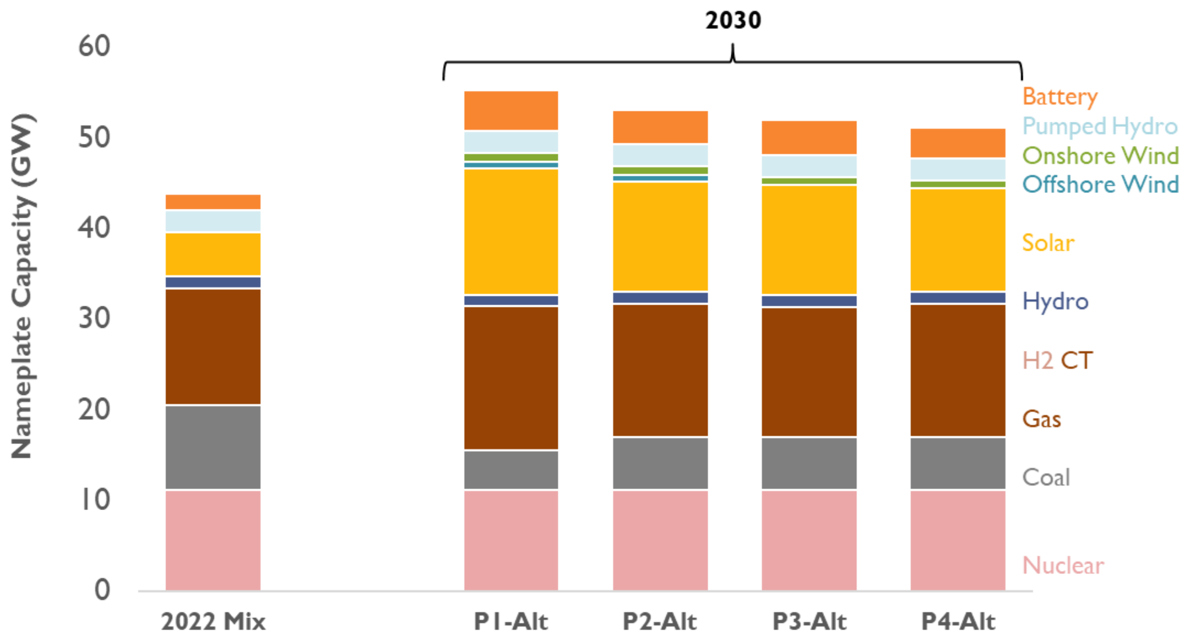


Figure 15 shows incremental resource builds and retirements between 2030 and the end of the planning period. The 2030–2050 period presents a dramatically different set of resource additions and retirements than capacity changes 2022–2030. Over this timeframe, roughly half of capacity additions are over 20 GW of new nuclear and hydrogen gas turbines, while a substantial amount of Duke's existing gas capacity and Duke Energy's remaining coal units are presumed to retire. Addition of solar and storage technologies slow substantially compared to the first decade of the planning period. The only immediately noticeable difference between portfolios is Portfolio 2's investment in offshore wind resources in the early 2030s.

Figure 15. Incremental Resource Builds and Retirements, 2030–2050

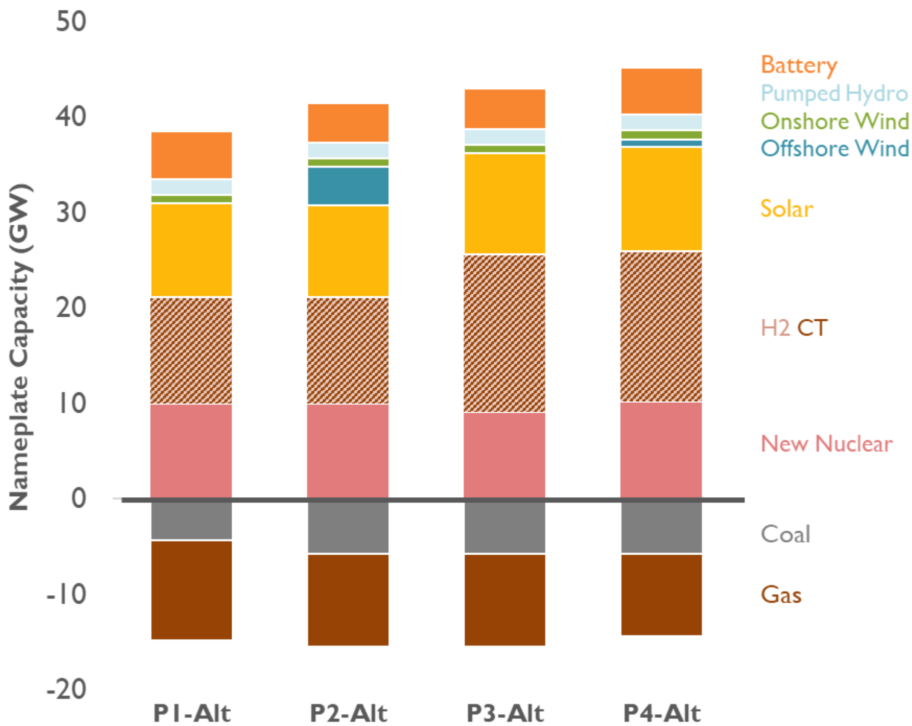
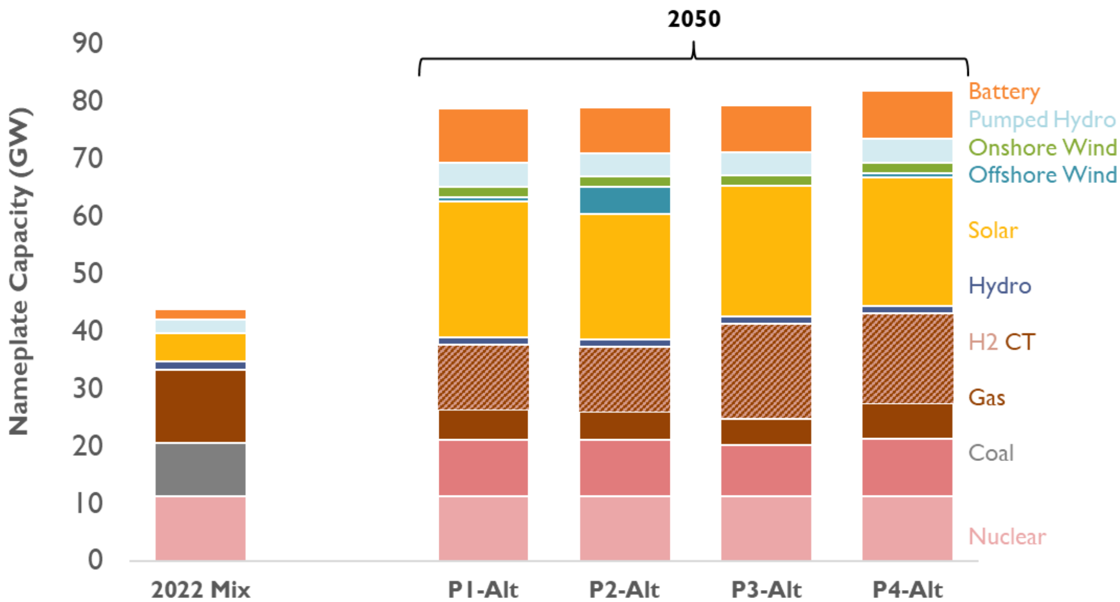


Figure 16 shows the final capacity mix of resources across Duke Energy portfolios in 2050 versus present-day capacity in 2022. Roughly half of capacity across portfolios is comprised of existing and new nuclear resources plus hydrogen-burning resources. Most of the remaining capacity is solar resources, with several GW of pumped hydro and battery storage. Again, one of the only noticeable differences between portfolios is several GW of offshore wind found in P2-Alt.

Figure 16. Capacity by Resource Type, 2022 and 2050, by Scenario



Overall, Duke Energy's proposed portfolios might better be thought of as variations on a single resource pathway than four distinct approaches to achieving a zero-carbon energy system. The portfolios share an identical short-term action plan, and, despite some differences in resource timing, they all have very similar total builds and projected generation mixes in 2050. Despite these similarities, only Portfolio 1 is designed to meet HB 951's 70 percent carbon reduction requirement by 2030. Nevertheless, Duke Energy's modeling shows that their P1–Alt scenario fails to meet its 70 percent carbon requirement in 2030.[46]

Consistent with their generation and capacity mixes, net present-value revenue requirements are also very similar across proposed portfolios. NPVRR results for each portfolio are presented below in Table 11. These costs are based on Duke Energy's model inputs, which are further discussed in Section 2 and Appendix A; these costs should not be directly compared with the results of Synapse's analysis, but are helpful for comparing between portfolios. As expected, there is little cost variation in Duke Energy's reported results.

[46] Appendix E, p. 89.

Table 11. Net Present Value Revenue Requirement over Time, Duke Portfolios

Results (2022-2050)	*P1-Alt*	*P2-Alt*	*P3-Alt*	*P4-Alt*
2050 NPVRR ($B)	$105.5	$102.7	$99.8	$100.2

Note: Costs reported by Duke Energy, adapted from Confidential Duke Energy Response to Public Staff Data Request 3-13 Corrected. Counsel from Duke Energy verified that no confidential material has been divulged relating to this confidential response to data request.

4.6. Role of New Nuclear and Green Hydrogen Resources

A common thread across all the portfolios in Duke Energy's proposed Carbon Plan is their dependence on SMR and zero-carbon hydrogen resources, neither of which are commercially available today. Duke Energy's proposed portfolios plan to deploy around 10 GW of new nuclear units over the next 20 years, alongside enough zero-carbon hydrogen generation, transport, and distribution to supply 11 to 16 GW of new-build hydrogen-burning units or retrofitted natural gas units. Both technologies present economic and operational risks to Duke Energy ratepayers, who will ultimately bear the economic burden of building and fueling these resources.

While several small nuclear reactors are in the early stages of development, it is not clear that any will be operational in the 2020s. In 2020, several utilities that had recently partnered with SMR first-mover Nuscale announced that they would back out of a deal to purchase power from the plant after Nuscale announced a $2 billion cost overrun.[47] More recently, changing geopolitics and supply chains have destabilized the supply of enriched uranium used to fuel the Natrium reactors contemplated by Duke Energy in their proposed portfolio.[48] Risks associated with construction costs and timelines have haunted recent nuclear projects in the Southeast, including the VC Summer plant in South Carolina[49] and Plant Vogtle in Georgia,[50] and while SMRs represent a new technology, these predominantly unlicensed designs bring their own

[47] Cho, A. (2020, November). Several U.S. utilities back out of deal to build novel nuclear power plant. *Science*. Retrieved at: https://www.science.org/content/article/several-us-utilities-back-out-deal-build-novel-nuclear-power-plant.

[48] Bleizeffre, D. (2022, March). Nixed Russian fuel supply complicates Natrium schedule. *Wyofile.* Retrieved at: https://wyofile.com/nixed-russian-fuel-supply-complicates-natrium-schedule/.

[49] Associated Press (2022, May). "$61 Million in Refunds for Customers in SC Nuclear Debacle." *US News & World Report*. Retrieved at: https://www.usnews.com/news/us/articles/2022-05-04/61-million-in-refunds-for-customers-in-sc-nuclear-debacle.

[50] Jones, E. (2022, June). "Plant Vogtle co-owners sue Georgia Power over cost overruns." *WABE*. Retrieved at: https://www.wabe.org/plant-vogtle-co-owners-sue-georgia-power-over-cost-overruns/.

risks and uncertainties. Early commitment to an unproven technology before it has reached commercial viability could present substantial risks for ratepayers' bills and carbon emissions trajectories.

Hydrogen electrolysis represents a more mature technology because of the use of hydrogen in industrial settings. Uncertainties remain, however, in the role that hydrogen will play as a fuel for power generation.

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Industry publications point toward the broader use of zero-carbon hydrogen across a de-carbonized economy;[51] Duke Energy's hydrogen supply analysis does not contemplate demand for zero-carbon hydrogen outside of power generation.[52]

Industry publications also continue to indicate the need for future research to develop a pathway for retrofitting existing gas turbines to burn 100-percent hydrogen for existing gas units.[53] At the same time, hydrogen resources will continue to struggle to compete economically against other generation resources. The Hydrogen Council notes that "Hydrogen is only relevant in regions constrained in renewables potential," and projects that the long-term cost of hydrogen power will be $140/MWh.[54] Finally, operation of hydrogen at scale for power generation in the Carolinas presumes the successful buildout of a hydrogen production, transport, and distribution infrastructure that does not exist today, as well as a tectonic shift from the emissions-intensive steam methane reformation process, which emits carbon dioxide and is used to produce 95 percent of hydrogen in the United States today, to hydrogen electrolysis powered by clean electricity.[55] Beyond the build-out of renewable generation capacity (e.g., wind and solar) to provide zero-carbon power for electrolysis, building out the

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[51] Hydrogen Council (2020, January). Path to hydrogen competitiveness: A cost perspective. Retrieved at: https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf.

[52] Appendix E, p. 102.

[53] ETN Global (2020, January). Hydrogen Gas Turbines. Retrieved at: https://etn.global/wp-content/uploads/2020/01/ETN-Hydrogen-Gas-Turbines-report.pdf.

[54] Hydrogen Council (2020, January). Path to hydrogen competitiveness: A cost perspective. Retrieved at: https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf.

[55] Hernandez, D. D., & Gençer, E. (2021). Techno-economic analysis of balancing California's power system on a seasonal basis: Hydrogen vs. lithium-ion batteries. *Applied Energy*, 300, 117314.

infrastructure for green zero-carbon hydrogen will require substantial investment in electrolyzers and transport infrastructure (i.e. hydrogen-capable pipelines). These investments and their attendant costs are not captured by Duke's modeling in their proposed Carbon Plan.[56]

While these technologies show promise as tools in the clean energy toolkit, there are still substantial cost and operational uncertainties and concerns for their large-scale deployment. Duke Energy's proposed portfolios place an undue dependence on these technologies, driving additional risks and potential costs to ratepayers.

5. Conclusions

Synapse's EnCompass analysis shows that the most cost-effective portfolios to achieve affordable, de-carbonized power for North Carolina are those that prudently invest in proven, low-cost, zero-emissions resources like energy efficiency, solar, wind, and battery storage, and avoid any additional investments in fossil fuel-based generation. These proven resources support an accelerated exit from coal in the short term and, in the long term, drive substantial cost savings compared to Duke Energy's proposals. Based on this analysis, Synapse provides the following conclusions:

- While Duke Energy's adoption of the EnCompass resource planning tool created the opportunity for increased transparency, several manual overrides by Duke in their proposed portfolios undermined the EnCompass software's ability to optimize for the most cost-effective portfolio.
- Synapse's analysis found no justification for any additional gas-fired resources on the basis of cost-effectiveness or capacity reserve requirements. Given the carbon emissions associated with gas plants, the uncertainties around de-carbonizing these units in the future by repowering them to burn hydrogen or another fuel, the risk of price spikes from volatile gas markets, the costs of these units, and the capacity value of available alternative zero-carbon resources, there is little justification for building additional gas-fired resources.
- Energy efficiency reduces both peak loads and total energy needs and represents a key part of any cost-effective long-term energy plan. Synapse's base energy efficiency assumption of 1.5 percent of total retail load is consistent with peer

[56] Duke Energy Response to Clean Power Supply Association ("CPSA") DR 1-6.

utilities,[57] and Duke Energy ratepayers would benefit from this higher level of energy efficiency savings. Ratepayers also benefit from expanded adoption of distributed energy resources, which further reduce load and avoid the need to invest in supply-side resources.

- Across Duke Energy's and Synapse's modeling, accelerated and increased solar deployment is a cornerstone of a cost-effective carbon-reduction portfolio. Duke Energy should not only continue to procure cost-effective solar power from third-parties, but also take decisive steps now to improve their transmission planning process to lift the constraints currently hindering solar deployment.

- In all scenarios, battery storage plays an important role by bolstering the economic value of low-cost solar power. Duke Energy should move ambitiously to integrate battery storage resources and build out operational capabilities for capitalizing on their services to the grid.

- Synapse's modeling finds that a scenario that includes power purchase agreements for Midwest wind deliver power at a lower cost to ratepayers. This is true even when accounting for the cost of transmission from PJM using firm point-to-point transmission rates. This result shows the potential for increased regional coordination and transmission to unlock lower-cost resources and ultimately lower costs for ratepayers. Expanded transmission and regional coordination should continue to be an area of detailed analysis in ongoing resource planning.

- In the later years of the planning horizon, Synapse's EnCompass analysis found that it was more economical to retire existing gas resources rather than retrofit them for burning hydrogen. This result reflects the present and accelerating risk that incremental gas-fired resources play due to their carbon emissions. Any incremental investments in gas-fired resources would face these risks even earlier in their operating lifetimes. Ongoing technical and economic uncertainties around hydrogen retrofits compound these risks for existing and potential gas-fired units.

- In the long term, Duke Energy's Carbon Plan portfolios lean heavily on assumptions that small, modular nuclear reactors and zero-carbon hydrogen will be available and more cost-effective than proven technologies on the grid today. While both SMRs and hydrogen may play a role in a decarbonized energy grid, substantial cost and operational questions about these resources remain. Relying heavily on these unproven technologies, especially by building additional carbon-emitting units with the hope that they may later be decarbonized by an

[57] Relf, G., Cooper, E., Gold, R., Goya, A., & Waters, C. (2020, February). 2020 Utility Energy Efficiency Scorecard. American Council for an Energy Efficient Economy. P. 26. Retrieved at: https://www.aceee.org/sites/default/files/pdfs/u2004%20rev_0.pdf.

effective retrofit process and a commercialized supply of widely available, zero-carbon hydrogen, subjects ratepayers to substantial economic risk. Synapse's analysis shows that using proven technologies available today can deliver a cost-effective, zero-carbon grid without relying heavily on unproven resources.

- A sensitivity testing the impact of joining the Regional Greenhouse Gas Initiative on Duke Energy's emissions found that joining RGGI would reduce emissions by hundreds of thousands of tons of carbon per year in the late 2020s and early 2030s. Notably, incremental emissions reductions from participation in RGGI allowed the *Duke Resources* portfolio to achieve their HB 951 carbon reduction requirement in 2030.

Appendix A. Detailed Description of Revisions to Duke Modeling Assumptions

A.1. Revised Inputs

Gas Fuel Price Forecast

Figure A-1 shows Synapse and Duke Energy gas price forecasts. Synapse's gas price forecast is based on a blend of the most recent near-term New York Mercantile Exchange (NYMEX) futures prices, and long-term fundamental gas price forecasts from the US Energy Information Administration's (EIA) 2022 Annual Energy Outlook (AEO). Consistent with Duke's methodology, the Henry Hub price forecast was also blended with a hydrogen price forecast beginning in 2035, as Duke Energy's proposed Carbon Plan includes blending of relatively low levels of hydrogen starting in 2035. Synapse made no changes to the timing and rate of blending. Synapse applied Duke's zonal adders for Transco Zones 4 and 5.

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Synapse's approach to developing the internal gas price forecast is very similar to Duke's. Both rely on the EIA's AEO for long-term gas price trajectory, although Synapse's fundamental forecast exclusively relies on the 2022 AEO forecast, while Duke Energy's forecast relies on an average of several long-term projections from Wood Mackenzie, EIA, and IHS Markit.[1]

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[1] Appendix E, p. 40.

Hydrogen Fuel Price Forecast

Synapse developed a hydrogen price forecast using a hydrogen production trajectory derived from Bloomberg New Energy Finance data[2] and hydrogen transportation costs from McKinsey & Company on behalf of the Hydrogen Council.[3] Figure A-3 shows a comparison between Synapse's hydrogen price forecast and Duke Energy's hydrogen price forecast. All hydrogen is assumed to be zero-carbon "green" hydrogen, generated using electrolysis with zero-carbon electricity.

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[2] Mitsubishi Power (2020, October). Advancing Green Hydrogen for the Danskammer Project. Retrieved at: https://www.greenhydrogenny.com/wp-content/uploads/2020/11/Mitsubishi-Advancing-Green-Hydrogen-for-the-Danskammer-Project.pdf.

[3] Hydrogen Council and McKinsey & Company (2020, January). Path to Hydrogen Competitiveness: A cost perspective. Retrieved at: https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf.

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Fixed Operations and Maintenance Costs of Existing Coal Resources

Synapse derived fixed operations and maintenance costs for Duke Energy's legacy coal units using a study conducted by Sargent & Lundy for EIA in 2018.[8] As opposed to the engineering approach used by Duke Energy, the Sargent & Lundy study used a regression-based analysis of historical operations and maintenance costs for coal units across the United States, using information reported by those units to EIA and the Federal Energy Regulatory Commission.[9]

Capital Expenditures, Project Lifetimes, and Hydrogen Retrofit Costs

Synapse relied on publicly available, industry-standard data sources to set capital expenditures for available resources in its optimization runs. For combustion turbines, combined-cycled units, and the two advanced nuclear technologies modeled by Duke Energy, Synapse used the same process as described by Duke Energy in its "New Supply-Side Resource Capital Cost Sensitivity Analysis," detailed in Appendix E.[10] Duke Energy sourced the cost references in its capital cost sensitivity from EIA's cost estimates characterized in EIA's 2022 AEO. For solar, wind, and storage technologies, Synapse used values from NREL's 2022 Annual Technology Baseline (ATB). The *Regional Resources* scenario uses a wind PPA cost estimate from NREL's 2022 ATB Moderate case.

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[4] US Department of Energy (2021, November). H2@Scale. Retrieved at: https://www.energy.gov/eere/fuelcells/h2scale.

[5] National Renewable Energy Laboratory (2021, October). Electric Hydrogen Partnership Hopes to Repeat Success with Renewable Hydrogen Technology. Retrieved at: https://www.nrel.gov/news/features/2021/electric-hydrogen-partnership-hopes-to-repeat-success-with-renewable-hydrogen-technology.html.

[6] Confidential Duke Energy Response to NCSEA-SACE DR 3-31.

[7] *Ibid.*

[8] Sargent & Lundy Consulting (2018, May). Generating Unit Annual Capital and Life Extension Costs Analysis: Final Report on Modeling Aging-Related Capital and O&M Costs. Prepared for US Energy Information Administration. Retrieved at: https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

[9] *Ibid.,* p. 4.

[10] Appendix E, p. 99-102.

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Synapse also revised the book and operating lives of several future resources. Table A-1, below, details changes to operating and depreciation lifetimes of selectable future resources.

Table A-1. Operating and Depreciation Lifetime for Selected Resources, Duke Energy and Synapse

Resource	Operational Lifetime		Depreciation Lifetime	
	Duke Energy	**Synapse**	**Duke Energy**	**Synapse**
Gas Combined-Cycle Unit	35	25	35	20
Gas Combustion Turbine	35	25	35	20
Offshore Wind	25	30	25	30

Source: Appendix E, p. 31, 32, 37.

Synapse assigned a 25-year operating lifetime and a 20-year depreciation lifetime to new construction gas-fired units to reflect the risk associated with carbon emissions from these units under North Carolina Session Law 2021-165 (HB 951) emissions requirements. There are still substantial cost, operations, and feasibility questions around retrofitting existing gas units for 100-percent hydrogen operations, and turbine manufacturers have called for more research into hydrogen retrofits.[11] Duke Energy's proposed Carbon Plan filing also states the need for more research into 100-percent hydrogen retrofits.[12] Duke Energy allows all additional combustion turbines to be converted to 100-percent hydrogen in its resource planning, despite this uncertainty. The depreciation and operational timelines used by Synapse allow new combustion turbines to take advantage of zero-carbon retrofits if they are available, but depreciate the assets in order to avoid stranded asset risk.

Synapse implements a 30-year operational lifetime for offshore wind projects, consistent with the NREL ATB.

Finally, Synapse used a publicly available academic article published in the *International Journal of Hydrogen Energy* to project hydrogen retrofit costs for existing and new-build gas-fired units.[13] The article projected 100-percent hydrogen retrofit costs would be equivalent to 25 percent of the unit's initial capital cost. Synapse's model implements retrofits in 2046 to ensure that units are available in 2047 for 100-percent hydrogen operation.

A.2. *Optimized* Scenario

Energy Efficiency Savings Forecast

Synapse developed a forecast of energy efficiency savings based on the same methodology used by Duke Energy. Synapse's energy forecast targeted incremental energy efficiency savings

[11] ETN Global is an international association of turbine manufacturers. Their January 2020 *Hydrogen Gas Turbines: The Path Towards a Zero Carbon Future* report states: "There is a requirement for research to address system, materials, operations, and control of gas turbines for their safe and economically effective transition to a hydrogen-containing fuel stream… [Research] is significantly less advanced at higher hydrogen firing levels." General Electric and Mitsubishi Hitachi Power Systems are members of ETN Global. *See:* ETN Global (2020, January). Hydrogen Gas Turbines: The Path Towards a Zero Carbon Future. P. 10. Retrieved at: https://etn.global/wp-content/uploads/2020/01/ETN-Hydrogen-Gas-Turbines-report.pdf.

[12] *See:* "To progress to 100% hydrogen-fueled turbines, substantial advancements in turbine technology are required." Appendix O, p. 6.

[13] Öberg, S., Odenberger, M., & Johnsson, F. (2022). Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems. *International Journal of Hydrogen Energy*, 47(1), 624-644. Retrieved at: https://www.sciencedirect.com/science/article/pii/S0360319921039768.

of 1.5 percent of total retail load per year, which is in line with peer utilities.[14] Steps followed by Duke and Synapse in developing energy efficiency forecasts are described below:

First, Duke Energy and Synapse identified annual incremental savings targets based on incremental savings projected in 2023 and retail load forecasts for Duke Energy Carolinas and Duke Energy Progress. Duke Energy calculates its base energy efficiency target as a percentage of 'eligible' retail load, or retail load net of entities that have opted out of energy efficiency programs. Duke Energy forecasts progress toward meeting incremental load targets by 2040.

Consistent with metrics used by the American Council for an Energy-Efficient Economy, Synapse used total retail load as the denominator for incremental savings targets. In Synapse's energy efficiency forecast, incremental savings achieve 1.5 percent of total retail load by 2030. Figure A-5 shows the incremental savings associated with the Duke Energy 'base' and 'high' incremental savings target and the Synapse incremental savings target. The graph shows results for Duke Energy Carolinas only, but it is broadly indicative of relative trajectories in both service territories.

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[14] The American Council for an Energy Efficiency Economy's 2020 Utility Efficiency Scorecard evaluated the 52 largest electric public utlities and included Incremental Energy Efficiency savings as a scoring category. The scorecard's sliding scale assigned a maximum of 8 points for annual incremental savings at 3 percent of retail load. The Scorecard awarded Duke Energy Carolinas 3 points and Duke Energy Progress 2.5 points in that category. *See:* Relf, G., Cooper, E. Goyal, A., Waters, C. (2020, February). 2020 Utility Energy Efficiency Scorecard. American Council for an Energy Efficient Economy. P. 26. Retrieved at: https://www.aceee.org/sites/default/files/pdfs/u2004%20rev_0.pdf.

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15 Confidential Duke Energy response to NC Public Staff DR 17-4.

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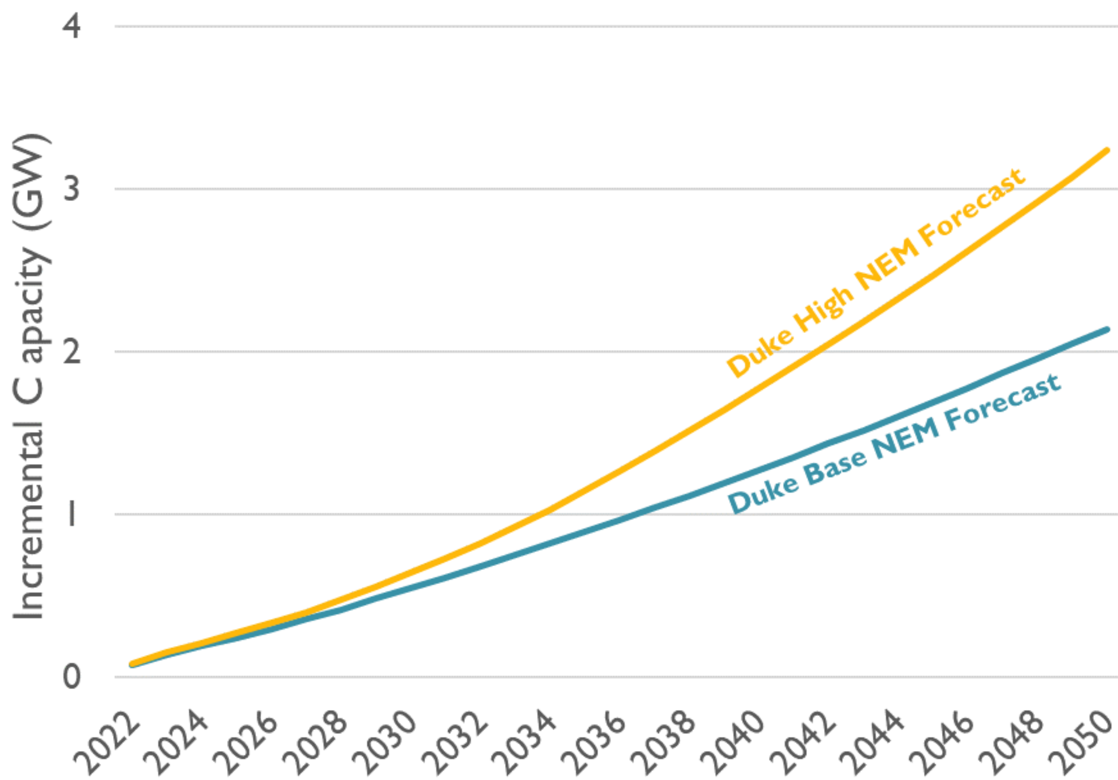
Synapse's energy efficiency forecast does not account for organic energy efficiency gains that might be induced from additional utility-sponsored energy efficiency (e.g., additional customers continuing to choose energy-efficient equipment after a utility incentive program ends, or after the utility-discounted equipment's operating lifetime). Incorporating induced energy efficiency would further reduce total load in the long term; maintaining the same level of organic energy efficiency represents a conservative approach to incremental energy efficiency.

Distributed Energy Resources Forecast

Synapse used net energy metering (NEM) forecasts provided by Duke Energy as an input to its load forecast. Figure A-7, below, shows incremental forecasted solar capacity by Duke Energy, in Duke's base and high net metering scenarios.

Figure A-7. Duke Energy Cumulative New NEM Capacity Forecast, 2022–2050



Source: Duke Energy Response to NCSEA-SACE DR 3-20.

Duke Energy's base NEM forecast assumes a relatively linear increase of 75 to 95 MW of incremental rooftop solar annually through 2050, resulting in just over 2 GW of incremental NEM capacity by 2050. The high NEM case assumes some acceleration of deployment, reaching 3.2 GW of incremental NEM capacity by 2050. The *Optimized* load forecast assumes Duke's high NEM forecast, while the *Duke Resources* load forecast assumes the base NEM forecast. Incremental capital expenditures are not included in these scenarios' NPVRR calculations.

Coal Retirements

Table A-2 shows coal units available for economic retirement by the EnCompass economic optimization algorithm in Synapse's EnCompass analysis. Synapse allowed all coal units expected to be operated after 2023 (apart from Cliffside 6, which is expected to run on 100-percent gas fuel) to be economically retired by the economic optimization algorithm during its capacity expansion runs. The latest possible retirement date for each year was set by Duke Energy's retirement dates in its proposed Carbon Plan portfolios; earlier retirement dates for each of these units could be selected by the economic optimization algorithm if doing so would be cost-effective. Synapse maintained the requirement that paired units (Marshall units 1-2 and 3-4, Roxboro units 1-2 and 3-4) be retired simultaneously.

Table A-2. Coal Units Available for Economic Retirement

Coal Units	Nameplate Capacity (MW)	Latest Retirement Year
Belews Creek 1	1,110	2036
Belews Creek 2	1,110	2036
Cliffside 5	546	2026
Marshall 1	380	2029
Marshall 2	380	2029
Marshall 4	660	2033
Marshall 3	658	2033
Mayo 1	713	2029
Roxboro 1	380	2029
Roxboro 2	673	2029
Roxboro 3	698	2028
Roxboro 4	711	2028

Source: Appendix E, p. 49.

Existing Gas Retirements

The *Optimized* and *Regional Resources* scenarios also allowed Duke Energy's existing gas-fired resources that are projected to undergo a hydrogen retrofit in Duke Energy's proposed Carbon Plan to be economically retired by EnCompass. Table A-3 shows a list of existing gas resources that were available to be retired by EnCompass in the *Optimized* and *Regional Resources* scenarios.

Table A-3. Existing Duke Energy Gas-Fired Units Projected for Hydrogen Retrofit

Gas Unit	Nameplate Capacity (MW)	Construction Year	Projected Retirement Year
Asheville Combined Cycle	560	2019	None
W.S. Lee Combined Cycle	750	2017	None
Lincoln Combustion Turbine 17	402	2020	None
Sutton Combustion Turbines	84	2017	None

New Nuclear Availability

Duke Energy's scenarios project that up to 21 new advanced and small modular nuclear reactor units could be built in Duke Energy's territory through 2048.[16] With the first units only available

[16] Appendix E, p. 33-36.

to come online in 2033, this pace is roughly equivalent to more than one new-construction nuclear unit per year every year in the Carolinas through the 2030s and 2040s.

Neither of the nuclear unit designs contemplated by Duke Energy in its proposed Carbon Plan have been constructed, nor have they received licenses from the US Nuclear Regulatory Commission.[17] The Tennessee Valley Authority (TVA) has made some limited progress toward developing a small, modular nuclear reactor, but noted in February 2022 that decisions made to date are "not a commitment to build."[18] TVA's goal for the project is for an advanced reactor to be deployed in the 2032 timeframe. Efforts to develop a small modular nuclear unit at the site have been under way since before 2016, when TVA applied for an early site permit at the Clinch River site.[19] While first-of-a-kind construction timelines are expected to be significantly longer than subsequent deployments, construction and operational uncertainties remain given the relatively untested nature of these designs.

Given that even the first small modular and advanced nuclear units are projected to be built in the late 2020s or early 2030s, Synapse applied a more reasonable availability trajectory that would allow North Carolina ratepayers to learn from early deployments without committing to nuclear unit designs before they are tested in the field. Synapse optimization runs allow for up to four nuclear units to be selected across Duke Energy Carolinas and Duke Energy Progress through 2050, with the first nuclear unit to be built in 2035.

Solar Availability

Like Duke Energy, Synapse modeled maximum annual solar deployment ramping up to 1,800 MW per year in the mid-to-late 2020s. To account for planned solar deployment through the mid-2020s, Synapse capped incremental solar additions at 1,200 MW in 2025, before increasing to 1,800 MW in 2026–2028. In 2029 and onward, Synapse incrementally increased maximum annual solar deployment to 2,300 MW, representing additional technical and procedural

[17] United States Nuclear Regulatory Commission (2022). GE-Hitachi BWRX-300. Retrieved at: https://www.nrc.gov/reactors/new-reactors/smr/bwrx-300.html.
United States Nuclear Regulatory Commission (2022). Natrium. Retrieved at: https://www.nrc.gov/reactors/new-reactors/advanced/licensing-activities/pre-application-activities/natrium.html.

[18] Patel, S. (2022, February). "TVA Unveils New Nuclear Program, First SMR at Clinch River Site." *POWER Magazine*. Retrieved at: https://www.powermag.com/tva-unveils-major-new-nuclear-program-first-smr-at-clinch-river-site/.

[19] US Nuclear Regulatory Commission. Early Permit Site Application – Clinch River Nuclear Site. Retrieved at: https://www.nrc.gov/reactors/new-reactors/smr/clinch-river.html.

benefits that will be realized over the next decade. This is consistent with national studies that anticipate continued improvements in solar deployment ability.[20]

Storage Availability

Given the modular nature and small footprint of lithium-ion batteries and the potential benefit of this technologies for operating the grid and integrating variable renewable energy resources, Synapse removed the constraints on cumulative deployment applied by Duke Energy to energy storage resources in its capacity expansion runs. Synapse applies an annual deployment ceiling of 1.5 GW of 4-hour storage batteries in Duke Energy Carolinas and Duke Energy Progress respectively to ensure operational viability, but otherwise does not apply additional constraints to storage deployment.

A.3. *Regional Resources* Scenario

Midwest Wind Purchase

In the *Regional Resources* scenario, Synapse included a Midwest wind resource that represented a power purchase agreement from the PJM region. These resources were designed to imitate the Midwest wind resources contemplated in the North Carolina Transmission Planning Consortium's 2021 Public Policy Study.[21] Notably, the NCTPC did not specify any transmission project identified through the study as being exclusively or mainly to support Midwest wind import. Power purchase agreement prices were projected from NREL's 2022 ATB, using the "Moderate" case levelized-cost-of-energy projection for Class 6 onshore wind resources. Once purchased, the energy price for each power purchase agreement is projected to escalate at the rate of inflation.

Consistent with Duke's methodology for onshore wind, Synapse modeled the projected costs of transmission by using PJM's current border charge of $67,625 per MW-year, rising at the rate of inflation over the planning period.

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[20] Princeton University's 2021 *Net Zero America* study; National Renewable Energy Laboratory's *Solar Futures* Study.

[21] North Carolina Transmission Planning Consortium (2022, May). Report on the NCTPC 2021 Public Policy Study. Retrieved at: http://www.nctpc.org/nctpc/document/REF/2022-05-10/NCTPC_2021_Public_Policy_Study_Report_05_10_2022_Final_%20Draft.pdf.

Appendix B. ADDITIONAL DESCRIPTION OF ENCOMPASS VALIDATION AND CONFIGURATION

Synapse and Duke Energy both used the EnCompass analysis software for the purposes of developing and analyzing Carbon Plan resource portfolios. Synapse is confident that this shared foundation of model inputs will create opportunities for collaboration and learning between parties in this and future proceedings, and Synapse is appreciative of the efforts undertaken by the North Carolina Utilities Commission and Duke Energy staff to make the sharing of data inputs possible. Duke Energy's EnCompass database, shared with intervenors on May 16, forms the backbone of Synapse's analysis. This appendix provides additional detail on Synapse's EnCompass analysis, including validation with Duke Energy results, resolution of an error caused by a later version of EnCompass, and changes to EnCompass configuration that Synapse implemented in its analysis.

Issues with Validation of Duke Energy's EnCompass Results. Duke Energy provided model outputs alongside their EnCompass database inputs to intervenors on May 16, 2022. These outputs allowed intervenors to perform validation of their own EnCompass database configurations: If the results of any intervenor's EnCompass analysis using Duke Energy inputs matched the results provided by Duke Energy, then the intervenor could be confident that their EnCompass database was configured appropriately and Duke Energy inputs were successfully imported. However, Synapse encountered several issues with model validation, which Duke Energy confirmed when it sent an update memo to intervenors on June 8:

- An issue with one portion of Duke Energy's EnCompass database caused the modeling runs to fail to complete.
- Outputs provided by Duke Energy were generated from an EnCompass database that was configured differently than the database that Duke Energy provided to intervenors. As a result, intervenors' modeling analyses consistently generated discrepancies with Duke Energy's own outputs.

Synapse recognizes that resource planning models are complex and encountering and resolving issues is an inevitable part of sharing modeling data; nevertheless, these issues delayed Synapse's, and presumably other intervenors', ability to engage with Duke Energy's modeling in ways that would be productive in building a shared understanding of least-cost carbon emissions reduction pathways for North Carolina.

EnCompass Versioning Issues. When Synapse began EnCompass analysis of Duke Energy's Carbon Plan filing, Synapse's EnCompass infrastructure used version 6.0.9, which included several modeling improvements compared to EnCompass version 6.0.4 that Duke Energy used in developing its Carbon Plan. After getting confirmation from Anchor Power Solutions that versions 6.0.9 and 6.0.4 used the same data structure, Synapse decided to use the more recent version of EnCompass for its own analysis. Synapse provided analysis results generated using EnCompass version 6.0.9 to RMI for its Optimus analysis.

On July 13, Synapse received an email from Anchor Power Solutions, EnCompass's vendor, confirming a previously unidentified error within EnCompass. This error caused EnCompass version 6.0.9 to model units capable of co-firing, such as Belews Creek 1 and 2, Cliffside 5 and 6, and Marshall 3 and 4, inaccurately. Effectively, these units were able to run on gas exclusively, rather than co-firing with coal. While the issue affected only these units directly, it created indirect impacts on coal unit retirements, system dispatch, energy prices, and CO_2 emissions for the 2022-2036 period while these units were in operation. In terms of net present value revenue requirement, Synapse observes a difference of 1 to 3 percent between *Duke Resources* outcomes using versions 6.0.4 and 6.0.9. After learning of the issue, Synapse decided to re-develop its scenarios with EnCompass version 6.0.4 to avoid any inaccuracies caused by this error. Table B-1, below, shows net present value revenue requirement for the *Duke Resources* scenario for EnCompass versions 6.0.9 (which contained the EnCompass error) and 6.0.4 (which matches Duke Energy's analysis).

Table B-1. Net Present Value Revenue Requirement by EnCompass Version, *Duke Resources* Scenario

Results (2022-2050)	*Duke Resources – 6.0.9*	*Duke Resources – 6.0.4*
2030 NPVRR ($B)	$35.8	$36.7
2040 NPVRR ($B)	$76.5	$77.7
2050 NPVRR ($B)	$120.0	$121.2

Changes to EnCompass Configuration:

Planning horizon. When conducting capacity expansion and production cost modeling, the "planning horizon" represents the span of time over which the algorithm optimizes costs. While longer planning horizons allow economic optimization to plan for the future and incorporate more information into planning decisions, the computing resources and time needed to solve problems with long time horizons can increase substantially. Analysts must strike a balance by setting a planning horizon that is long enough for the optimization to meaningfully plan for the future without creating modeling challenges for their hardware. One strategy to manage computing resources Is to solve a long planning period in "segments," where the user sets the software planning horizon for a fraction of the total span of time being analyzed, then EnCompass performs economic optimization on each fraction in sequence.

In the context of the current energy transition, where technology costs are changing rapidly and emissions are expected to decline over a multi-decadal time scale, longer planning horizons are important for integrating long-run industry transitions. Planning horizons that are too short may prevent resource planning tools like EnCompass from adequately taking long-term trends into account. Because the operation and depreciation lifetime of most resources typically extends past the modeling horizon, planning horizons that are too short can commit a system to a given resource in the early years that ultimately proves uneconomical in the long-term.

Capacity expansion modeling runs performed by Duke Energy to develop its Carbon Plan proposed portfolios used a series of 8-year segments and a final 5-year segment (i.e., 2022-2029, 2030-2037, 2038-2045, and 2046-2050).[22] While 8-year planning segments are within the reasonable range of planning horizons used in detailed capacity expansion modeling, they also introduce risks that resources selected in the earliest segments may not be economical resource choices when viewed over the long term.

Synapse's capacity expansion modeling runs also used a segmented approach, but the Synapse capacity expansion runs used one 15-year segment and one 14-year segment (i.e., 2022-2036, 2037-2050). This 15-year approach strikes an appropriate balance between computing resource efficiency while allowing economic optimization to make decisions that take a long-term view of emissions and technology price trajectories into account.

Capital Expenditures. EnCompass includes a detailed financial model that replicates the key components of utility financial analysis, including rate base, total carrying costs, and annual revenue requirement. For its Carbon Plan proposal, Duke Energy used its own proprietary calculation of a real fixed levelized costs for each new resource, which it imported directly into EnCompass. While this approach does not necessarily add any inaccuracy into EnCompass results, it inhibits the ability for stakeholders to make changes or revisions to capital cost calculations without re-developing Duke Energy's proprietary economic carrying cost calculations. Synapse's analysis converted the Duke Energy real fixed levelized costs back to capital expenditures and financial parameters (e.g. debt and equity rates, treatment of advanced funds used during construction) that are directly readable by EnCompass.

[22] Duke Energy response to NCSEA-SACE DR 3-7.

APPENDIX C. LOAD AND CAPACITY TABLES BY SCENARIO

Tables C-1 and C-2. Total Nameplate and Capacity and Net Builds and Retirements, *Duke Resources* Scenario

Year	Net Load (GWh)	Total Nameplate Capacity (MW)									
		Nuclear	Coal	Gas	Hydrogen	Hydro	Solar	Wind (Offshore)	Wind (Onshore)	Pumped Hydro	Battery Storage
2022	156,000	11,200	9,300	12,900	0	1,300	4,900	0	0	2,300	0
2025	157,000	11,200	8,900	12,700	0	1,300	6,500	0	0	2,500	300
2030	161,000	11,200	4,400	15,800	0	1,300	13,900	800	900	2,500	2,100
2035	169,000	12,000	3,100	15,800	0	1,300	19,500	800	1,800	4,100	3,600
2040	179,000	14,300	800[1]	15,300	1,500	1,300	23,500	800	1,800	4,100	7,100
2045	190,000	18,600	800[1]	9,900	2,300	1,300	23,800	800	1,800	4,100	9,300
2050	203,000	21,000	0	5,300	11,300	1,300	23,800	800	1,800	4,100	8,600

Year	5- Year Net Builds and Retirements (MW)									
	Nuclear	Coal	Gas	Hydrogen	Hydro	Solar	Wind (Offshore)	Wind (Onshore)	Pumped Hydro	Battery Storage
2022-2025	0	-400	-200	0	0	1,600	0	900	200	300
2026-2030	0	-4,500	3,100	0	0	7,400	800	900	0	1,800
2031-2035	855	-1,300	0	0	0	5,600	0	0	1,600	1,500
2036-2040	2,300	-2,300	-500	1,500	0	4,000	0	0	0	3,500
2041-2045	4,300	0	-5,400	800	0	300	0	0	0	2,200
2046-2050	2,400	-800[1]	-4,600	9,000	0	0	0	0	0	-700

[1] Cliffside 6, which is projected to run exclusively on gas.

Tables C-3 and C-4. Total Nameplate and Capacity and Net Builds and Retirements, *Optimized* Scenario

Year	Net Load (GWh)	Total Nameplate Capacity (MW)									
		Nuclear	Coal	Gas	Hydrogen	Hydro	Solar	Wind (Offshore)	Wind (Onshore)	Pumped Hydro	Battery Storage
2022	156,000	11,200	9,300	12,900	0	1,300	4,900	0	0	2,300	0
2025	157,000	11,200	8,300	12,700	0	1,300	7,300	0	0	2,500	300
2030	157,000	11,200	4,400	12,700	0	1,300	13,900	800	900	2,500	5,900
2035	160,000	11,200	800[1]	12,700	0	1,300	20,300	800	1,200	4,100	7,600
2040	166,000	11,200	800[1]	11,900	0	1,300	28,900	800	1,500	4,100	17,300
2045	175,000	12,700	800[1]	6,400	0	1,300	38,400	800	1,700	4,100	26,000
2050	186,000	13,200	0	1,000	5,300	1,300	44,800	800	1,800	4,100	30,800

Year	5- Year Net Builds and Retirements (MW)									
	Nuclear	Coal	Gas	Hydrogen	Hydro	Solar	Wind (Offshore)	Wind (Onshore)	Pumped Hydro	Battery Storage
2022-2025	0	-1,000	-200	0	0	2,400	0	0	200	300
2026-2030	0	-3,900	0	0	0	6,600	800	900	0	5,600
2031-2035	0	-3,600	0	0	0	6,400	0	300	1,600	1,700
2036-2040	0	0	-800	0	0	8,600	0	300	0	9,700
2041-2045	1,500	0	-5,500	0	0	9,500	0	200	0	8,700
2046-2050	500	-800[1]	-5,400	5,300	0	6,400	0	100	0	4,800

Tables C-5 and C-6. Total Nameplate and Capacity and Net Builds and Retirements, *Regional Resources* Scenario

Year	Net Load (GWh)	Total Nameplate Capacity (MW)									
		Nuclear	Coal	Gas	Hydrogen	Hydro	Solar	Wind (Offshore)	Wind (Onshore)	Pumped Hydro	Battery Storage
2022	156,000	11,200	9,300	12,900	0	1,300	4,900	0	0	2,300	0
2025	157,000	11,200	8,300	12,700	0	1,300	7,000	0	0	2,500	300
2030	157,000	11,200	2,200	12,700	0	1,300	9,900	0	3,400	2,500	4,200
2035	160,000	11,200	800[1]	12,700	0	1,300	16,700	0	3,700	4,100	5,000
2040	166,000	11,200	800[1]	11,500	0	1,300	26,200	0	3,700	4,100	13,700
2045	175,000	11,700	800[1]	6,000	800	1,300	36,100	0	4,200	4,100	24,800
2050	186,000	12,200	0	600	8,300	1,300	43,200	0	4,300	4,100	28,900

Year	5- Year Net Builds and Retirements (MW)									
	Nuclear	Coal	Gas	Hydrogen	Hydro	Solar	Wind (Offshore)	Wind (Onshore)	Pumped Hydro	Battery Storage
2022-2025	0	-1,000	-200	0	0	2,100	0	0	200	300
2026-2030	0	-6,100	0	0	0	2,900	0	3,400	0	3,900
2031-2035	0	-1,400	0	0	0	6,800	0	300	1,600	800
2036-2040	0	0	-1,200	0	0	9,500	0	0	0	8,700
2041-2045	500	0	-5,500	800	0	9,900	0	500	0	11,100
2046-2050	500	-800[1]	-5,400	7,500	0	7,100	0	100	0	4,100

CONFIDENTIAL APPENDIX D. DUKE COAL UNIT RETIREMENT DATES

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[END CONFIDENTIAL]

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 179

In the Matter of: Duke Energy Progress, LLC and Duke Energy Carolinas, LLC 2022 Biennial Integrated Resource Plans and Carbon Plan	))))))	Verification of Tyler Fitch

VERIFICATION

I, Tyler Fitch, first being duly sworn, say that I am employed as a Senior Associate at Synapse Energy Economics, Inc. and have read the foregoing report entitled, "Carbon-Free by 2050: Pathways to Achieving North Carolina's Power-Sector Carbon Requirements at Least Cost to Ratepayers," and know the contents thereof; and that the contents are true, accurate and correct to the best of my knowledge, information, and belief.

Signature

STATE OF Washington

COUNTY OF DC

Signed and sworn to (or affirmed) before me this 20th day of July, 2022.

Signature of Notary Public

Dominque Brown

Printed or Typed Name of Notary Public

My Commission Expires: 4-14-2026

[Official Seal or Stamp]

DOMINIQUE ANGELENE BROWN NOTARY PUBLIC Exp. - 04.14.2026 DISTRICT OF COLUMBIA