Clean, Affordable, and Reliable

A Plan for Duke Energy's Future in the Carolinas

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

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Executive Summary

The purpose of this report is to evaluate the 2020 Integrated Resource Plans (IRP) filed in North Carolina by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP), collectively "Duke Energy" or "Duke" and to present an alternative, optimized resource portfolio for the state.

Synapse Energy Economics (Synapse) used state-of-the-art electric simulation software to compare the relative cost to ratepayers of continuing Duke's investments in existing and new fossil-fueled resources versus a scenario that replaces Duke's coal fleet with a portfolio of renewables, storage, and energy efficiency reflecting updated and more realistic cost assumptions. The EnCompass model, licensed from Anchor Power Solutions, utilizes a detailed capacity expansion and production cost model that evaluates load and generation on an hourly basis, utilizing utility-specific load and generation profiles.

The results of Synapse's modeling demonstrate that the most economic path for North Carolina ratepayers is to retire Duke's coal-fired units at the Earliest Practicable retirement dates as determined by Duke, in contrast to keeping several units online beyond 2035. Results include:

- Synapse's model produces an alternate clean energy resource portfolio that **reduces total system cost by $7.4 billion** and **$CO_2$ emissions by 74 percent** compared to a scenario similar to Duke's modeled Base Case with Carbon Policy.
- Synapse's alternative scenario includes an increase in first year energy efficiency savings of 0.15 percent per year until it reaches 1.5 percent, at which point it is held constant. This results in approximately **16,500 GWh of net annual savings for 2035**, or 9.6 percent of the projected system load.
- Synapse's model selects new solar, wind, and battery storage resources to meet future capacity and energy needs, with no incremental gas capacity additions. This includes **17.8 gigawatts of new utility-scale solar**, **2.5 gigawatts of new onshore wind**, **750 megawatts of new offshore wind**, and **11.8 gigawatts of new battery storage** by 2035.
- Synapse's alternative scenario results in immediate additions of renewable energy capacity, beginning in 2022 and every year thereafter. This includes **4,300 MW of new renewable capacity from 2021-2026** and more than **9,000 MW from 2027-2031**, accounting for limitations to annual capacity additions.
- Synapse's model generates these results while **maintaining Duke's full 17 percent planning reserve margin**. Synapse's modeling reliably meets load in every hour of the 15-year planning period with no hours of loss of load or unserved energy.

Coal-fired power plants across the country are facing both rising fuel costs and increasing capital expenditures, and Duke's coal units are no exception. Synapse reviewed Duke's coal retirement analysis and found that it does not properly account for the cost and benefits of the coal-fired capacity and energy and thus fails to produce the most "economic" retirement date for individual units and for combinations of units. The method Duke used for its analysis avoids optimization, avoids a full economic analysis of coal units, and avoids competition with alternative resources like wind, solar, storage, and energy efficiency.

The cost of renewable resources has declined dramatically over the past decade and is expected to continue to do so. This trend has reached the point where it costs less to build and run renewables and storage than it does to maintain and operate existing coal units. These resources are currently competing head-to-head with gas-fired combustion turbines and are expected to become more economic than new combined cycle units in the coming years. Investments in renewables and storage also avoid the stranded asset risk that comes with investments in new gas capacity.

Duke has a viable pathway toward meeting a clean energy future, and that pathway is less expensive than continuing to invest in fossil-fueled power plants. However, it will require that Duke move affirmatively to retire existing coal, commit to renewables, storage and demand-side resources, and actively invest in the clean energy economy of the Carolinas.

1. INTRODUCTION

The Integrated Resource Plans (IRPs) filed by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) in September 2020 will shape the energy future of the Carolinas through 2035. These planning documents are driven by the need to forecast energy and peak demand in the DEC and DEP service areas between 2021 and 2035 and plan for a mix of generation and capacity resources that will achieve system reliability, meet state environmental goals, and provide cost-effective service to DEC and DEP ratepayers.

Duke's 2020 IRPs for North Carolina and South Carolina include six potential portfolios, five of which contain between 6,100 MW and 9,600 MW of new gas-fired generating units.[1] In Duke's IRP modeling, the need for these new combined cycle and combustion turbine gas units is driven by a combination of projected increases in electricity demand and the retirement of Duke's coal units. However, most of Duke's scenarios fail to achieve state climate goals – specifically, North Carolina's Clean Energy Plan, which calls for a 70 percent reduction in carbon dioxide (CO_2) emissions from the electric sector by

[1] Unless otherwise stated, references to "Duke IRP" include the combined results of DEC and DEP. Duke's six IRP scenarios are (A) Base With No Carbon Policy, (B) Base With Carbon Policy, (C) Earliest Practicable Coal Retirements, (D) 70% Reduction High Wind, (E) 70% Reduction High SMR, and (F) No New Gas.

2030.[2] In fact, the three Duke scenarios that rely most heavily on natural gas fail to achieve the 2030 target even by 2035.

Given the inevitability of carbon regulation, coupled with state carbon-reduction goals and Duke's own corporate goals, investments in gas infrastructure are increasingly at risk of becoming stranded assets. Duke's reliance on gas in its IRP modeling scenarios places the environmental and financial risks of new gas builds on ratepayers in North and South Carolina, and ignores alternative portfolios of solar, wind, storage, and energy efficiency resources that could also form the basis of Duke's electricity supply.

Synapse Energy Economics, Inc. (Synapse) conducted a capacity expansion and production cost modeling analysis that demonstrates the viability of an alternative resource portfolio that adds increasing amounts of energy efficiency, renewable energy, and battery storage resources in amounts above Duke's resource portfolios. Using the EnCompass model, Synapse developed two scenarios. In the first, Synapse uses Duke's input values to create a resource portfolio, "Mimic Duke," that results in a similar, but not identical, portfolio to that put forth in Duke's Base Case With Carbon Policy. In our alternative scenario, "Realistic Assumptions," Synapse modeled an alternate scenario that speeds the pace of coal retirements while increasing energy efficiency savings and adjusting the costs for specific renewable resource options offered to the model for replacement capacity and energy. The purpose of the Mimic Duke scenario is to show the importance of relying on a set of realistic assumptions in IRP modeling, and that the software is not the main driver of differences in the portfolio presented in the Realistic Assumptions scenario.

In contrast to Duke's Base Case portfolios, the Synapse alternative portfolio offers ratepayers in the Carolinas a more economic generation portfolio that also achieves state environmental goals and puts Duke on track to meet its corporate emission reduction goal of net-zero CO_2 by 2050.

2. Critique of Duke's Retirement Study

Economic assessments of existing coal units have become an increasingly common component of utility resource planning, whether undertaken voluntarily by utilities or done as the result of a state utility commission order. Examples include:

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[2] North Carolina Department of Environmental Quality. October 2019. *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System.* Available at: https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.

- In its 2018 IRP, Northern Indiana Public Service Company (NIPSCO) examined alternative retirement dates for its five existing coal units, concluding that customers would save more than $4 billion by retiring those units in 2023 rather than 2030.[3]
- PacifiCorp included a unit-by-unit retirement analysis of alternative retirement dates for its 22 coal units in its 2019 IRP, examining retirement dates occurring several years before the end of the units' depreciable lives.[4]
- Georgia Power included a retirement analysis for each of its existing coal units in its 2019 IRP.[5]
- Dominion Energy Virginia's 2020 Integrated Resource Plan compared the forecasted costs and benefits of retiring its coal units versus continuing to operate them in the PJM market, finding that it was economically beneficial to retire its Chesterfield and Clover units earlier than planned in the previous IRP under all scenarios analyzed.[6]
- As recently as December 2020 the Public Service Commission of South Carolina stated in its Order Rejecting Dominion's Integrated Resource Plan that "the evidence shows that the retirements included… were not based on a robust retirement analysis, assessing all the costs and benefits associated with near and mid-term retirement dates such as capital expenditures, environmental expenditures while considering all available resources as potential replacements."[7]

As part of the 2018/2019 process in North Carolina, the NCUC ordered Duke Energy Carolinas and Duke Energy Progress to include such an analysis as part of this 2020 IRP process.[8] Both companies state that they have conducted detailed coal plant retirement analyses that are intended to assess the on-going value of the plants and determine the most "economic" retirement dates.[9] Duke also examined a

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[3] Northern Indiana Public Service Company (NIPSCO). October 2018. *2018 Integrated Resource Plan*. Available at: https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2018-nipsco-irp.pdf?sfvrsn=15.

[4] Robert Walton, Utility Dive. September 2019. *PacifiCorp sees 2 GW coal retirements, $599M savings by 2040 in latest planning scenarios*. Available at https://www.utilitydive.com/news/pacifcorp-sees-2-gw-coal-retirements-599m-savings-by-2040-in-latest-plann/562670/.

[5] Georgia Power. January 2019. *2019 Integrated Resource Plan Technical Appendix Vol. 2: Unit Retirement Study*. Available at: https://psc.ga.gov/search/facts-document/?documentId=175473.

[6] Dominion Energy Virginia. *May 2020. 2020 Integrated Resource Plan, p. 83–84.* Available at: https://scc.virginia.gov/docketsearch/DOCS/4m_m01!.PDF.

[7] South Carolina Public Service Commission. December 23, 2020. Docket No. 2019-226-E, Order No. 2020-832: Order Rejecting Dominion's Integrated Resource Plan and Requiring Dominion to Make Modifications to its 2020 Integrated Resource Plan, Future Updates and Future Integrated Resource Plans. Available at: https://dms.psc.sc.gov/Attachments/Order/a4b59f43-e545-43bd-9f35-a846b7602c39.

[8] State of North Carolina Utilities Commission. February 2019. *Docket No. E-100 Sub. 157: Order Accepting Integrated Resource Plans and REPS Compliance Plan, Scheduling Oral Argument, and Additional Analyses.* Available at: https://starw1.ncuc.net/ncuc/ViewFile.aspx?Id=143d85de-b1e7-4622-b612-5a8c77e909d4; State of North Carolina Utilities Commission. April 2020. *Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans, p. 8–9*. Available at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=86f15be3-7617-4910-aeae-d8568
c4d0983.

[9] *Duke Energy Progress 2020 Integrated Resource Plan*, p. 79 (Nov. 6, 2020) ("DEP 2020 IRP"); *Duke Energy Carolinas 2020 Integrated Resource Plan*, p. 77 (Nov. 6, 2020) ("DEC 2020 IRP").

second set of retirement dates for its coal assets, which it called the "earliest practicable." However, Duke's methodology was insufficiently robust to answer this complex question. Duke's lack of documentation and nonexistent stakeholder process should give the North Carolina Utilities Commission little confidence that Duke has arrived at an optimal set of retirement dates for its coal-fired units.

The methodology that underlies Duke's retirement analysis has three steps: (1) Ranking plants for retirement analysis; (2) Sequential Peak Method (SPM); and (3) Portfolio Optimization. The first step in Duke's process was to develop a rank order in which the coal retirements would occur. While Duke did run capacity expansion and production cost models to examine the value of the units, it ultimately determined that the ranking should be based on the capacity of the units, retiring the smallest units first. Duke's unit rankings are shown in Table 1, below.

Table 1. Duke ranking of coal plants for retirement analysis[10]

Coal Facility	Capacity (MW Winter)	CF% Range Through 2035	Years in Service (As of 1/2020)	Rank
Allen 1-3	604	3%-11%	60-62	1
Allen 4-5	526	2%-9%	58-59	2
Cliffside 5	546	2%-23%	47	3
Mayo	746	1%-12%	36	4
Roxboro 1-2	1,053	5%-34%	51-53	5
Roxboro 3-4	1,409	1%-32%	39-46	6
Marshall 1-4	2,078	1%-49%	49-54	7
Belews Creek 1-2	2,220	16%-57%	44-45	8

Ranking the unit retirements based on capacity is a flawed methodology, as it ignores the costs associated with the operation of those units. Capacity and energy value both have a part to play in the overall economics of individual coal units and a rigorous retirement analysis would consider them both together. Due to the low capacity factors at even the largest of Duke's units, it could be more economic to retire the larger units first, which incur greater fixed costs due to their size, and retire the smaller units later in the analysis period. While Duke states it considered incremental coal ash costs in this step, it does not appear that Duke considered additional costs and risks associated with future environmental regulations when evaluating the costs of these plants to ratepayers. A robust analysis would identify and retire the worst performing and most costly units first to provide the most benefit for customers. Simply ranking the units from lowest to highest capacity does not accomplish that goal.

The range of capacity factors shown for groups of units in Table 1 represent the range in all years of the analysis period. The higher number in the range typically occurs in the first year of the analysis and capacity factors fall quickly to single digits for certain units. An examination of the capacity factors of

[10] DEP 2020 IRP. Page 82.

individual units, averaged over the number of years in which the unit is operational, is shown in Table 2 and presents a very different picture and rank order.

Table 2. Average Unit Capacity Factors During Operational Years (Duke Screening Study)[11]

Coal Facility	Area	Capacity (Summer MW)	Average Capacity Factor
Mayo 1	DEP	727	2.6%
Allen 2	DEC	162	3.4%
Allen 5	DEC	259	3.7%
Allen 1	DEC	162	3.8%
Allen 4	DEC	257	4.5%
Allen 3	DEC	258	6.0%
Roxboro 3	DEP	691	6.6%
Roxboro 1	DEP	379	7.7%
Roxboro 4	DEP	698	7.8%
Marshall 1	DEC	370	8.1%
Marshall 2	DEC	370	8.4%
Cliffside 5	DEC	544	12.0%
Roxboro 2	DEP	665	14.3%
Marshall 3	DEC	658	22.0%
Belews Creek 2	DEC	1,110	24.8%
Marshall 4	DEC	660	29.0%
Belews Creek 1	DEC	1,110	30.5%
Cliffside 6	DEC	844	N/A

The poor performance of Duke's coal units cannot be understated. The average capacity factors shown in Table 2 are very low for units that have historically been designated as "baseload," meaning they provide consistent, lower-cost energy over most hours in the year. However, many of Duke's coal-fired "baseload" units are instead being operated as peaking units. Data from the United States Environmental Protection Agency's Air Markets Program show that Allen Unit 1 operated for only nine days in all of 2020 and Allen Unit 2 operated for only eight days, notably in the summer months of July and August.[12]

The unit with the highest output in Duke's projections has an average capacity factor of only 30.5 percent, and more than half of Duke's units have average capacity factors of less than 10 percent. Units that are forced to cycle and go through more startups and shutdowns incur more wear and tear and thus require increased investments to ensure their reliability. Duke is getting little payback for these

[11] Values were calculated from Duke's response to ORS AIR 2-22 and the attachment "ORS_AIR 2-22 Coal Retirement Screening.xlsx"

[12] US Environmental Protection Agency. Air Markets Program Data. Available at: https://ampd.epa.gov/ampd/.

investments, though, as the units are providing little energy value to Duke's system, and that value is diminishing over time.

Duke's ranking methodology purposefully ignores these declining energy values. Duke explicitly states the following: "For instance, while Cliffside 5 has a higher capacity factor than Mayo, which would indicate Cliffside 5 has a higher production cost value, the lower capacity of Cliffside 5 requires less replacement generation at the time of retirement. For this reason, Cliffside 5 was ranked above Mayo in the order for conducting the retirement analysis."[13] This dubious logic avoids the most important criteria in retiring coal plants, or any piece of utility infrastructure – identifying the point in time when these units become economically disadvantageous to customers and ratepayers.

The second step in Duke's coal unit retirement approach is the "Sequential Peaker Method" (SPM), an internally developed process for determining the most economic retirement dates for coal plants. Duke applied this process to all of its coal units except Cliffside 6, which it expects to run on gas. The SPM method is based on what Duke calls a Net Cost of New Entry (Net CONE) method that considers the capital and fixed costs of a generic combustion turbine peaking unit, as well as the net production cost value of the peaker versus the existing coal unit being retired.[14] Each of the coal units is compared to a replacement combustion turbine; however, Duke's analysis is opaque at best and discovery responses to questions asking for more detailed information on the process were marked Confidential by Duke.

The application of Net CONE for a combustion turbine likely uses an artificially high cost for replacement capacity in many cases. Combustion turbines are a technology type that are unlikely to experience the kind of rapid price declines that are currently being seen for renewables and storage technologies, meaning that these costs will stay relatively constant over time, while costs for renewables and storage will go down over the next decade. A 2018 report by GTM Research and Wood Mackenzie predicted that energy storage technologies will regularly compete head-to-head with new gas-fired peaking units by 2022, and that new gas peakers will be rare by 2028.[15] Pairing a replacement battery with solar or allowing it to charge from the grid would make up the energy component associated with the gas-fired combustion turbine used by Duke in its SPM analysis.

The replacement energy cost associated with a gas-fired peaking unit could also be artificially high. Traditionally, combustion turbines have been thought of as being "cheap to build but expensive to run." Replacement resources with low variable costs, like wind and solar, would provide a better energy value for customers than a gas-fired peaking unit. Also missing from Duke's analysis is the inclusion of additional demand-side resources. The most economic resource portfolio will include both enhanced demand-side measures in addition to supply-side resources as a replacement for the capacity and energy from Duke's retiring coal units. If lower cost replacement resources were used as part of Duke's

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[13] DEP 2020 IRP. Page 83.

[14] DEP 2020 IRP. Page 83.

[15] Greentech Media. March 1, 2018. *Will Energy Storage Replace Peaker Plants?* Available at: https://www.greentechmedia.com/webinars/webinar/will-energy-storage-replace-peaker-plants#gs.6JwDozs.

analysis, it would likely change the most "economic" retirement date of Duke's coal-fired units. Portfolio analysis like that used in Duke's Step 3 is required at this step in the analysis in order to select replacement resources that replace all of the grid services of the retiring coal units and determine true economic retirement dates for these units.

Duke's SPM produces a result that is no different than the estimated depreciable lives that resulted from Duke's 2018 depreciation study.[16,17] A comparison of the depreciable life dates, the economic retirement dates, and the earliest practicable retirement dates is shown in Table 3. Except for the Allen units 2-4, which are taken at the plant level in the depreciation study, none of the economic retirement dates identified in Duke's retirement analysis occur any earlier than the end of the units' depreciable lives. Duke did not do an economic assessment of its coal fleet in its retirement analysis, but rather undertook a methodology that produces the exact same result as its depreciation studies.

[16] Direct Testimony of John J. Spanos for Duke Energy Progress, LLC. *In the Matter of: Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.* Before the North Carolina Utilities Commission Docket No. E-2, SUB 1219. Available at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=22094489-2fd5-46de-a228-571757f06434.

[17] Direct Testimony of John J. Spanos for Duke Energy Carolinas, LLC. *In the Matter of: Application of Duke Energy Carolinas, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.* Before the North Carolina Utilities Commission Docket No. E-7, SUB 1214. Available at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=46f3ba8e-b73a-4555-9d99-688087ed70b6.

Table 3. Comparison of Depreciable Life, Economic, and Earliest Practicable retirement dates[18]

Plant Name	Depreciable Life Date	Economic Retirement Dates (Jan 1)	Earliest Practicable Retirement Dates (Jan 1)
Allen 2	2024	2022	2022
Allen 3	2024	2022	2022
Allen 4	2024	2022	2022
Allen 1	2024	2024	2024
Allen 5	2024	2024	2024
Cliffside 5	2026	2026	2026
Roxboro 3	2028	2028	2028
Roxboro 4	2028	2028	2028
Roxboro 1	2029	2029	2029
Roxboro 2	2029	2029	2029
Mayo 1	2029	2029	2029
Marshall 1	2034	2035	2028
Marshall 2	2034	2035	2028
Marshall 3	2034	2035	2028
Marshall 4	2034	2035	2028
Belews Creek 1	2037	2039	2029
Belews Creek 2	2037	2039	2029
Cliffside 6	2048	2049	2049

The ability to replace coal-fired units with alternative resources like renewables and storage does not come into Duke's analysis until Step 3 – the Portfolio Optimization step. This included capacity expansion and production cost modeling based on the optimal retirement dates established using the SPM methodology. This modeling step is the basis for two portfolios that became Duke's "Base Case with No Carbon Policy" and "Base Case with Carbon Policy" scenarios. By this stage, however, Duke has already established the coal unit retirement dates, using a subjective rank-ordered screening study and a simple comparison to a generic peaker as opposed to a fully optimized retirement analysis. Duke's "optimization" step occurs long after coal plant retirement dates have been established. Duke should have instead conducted a full economic analysis of coal units that includes all of the costs associated with each unit as well as the value that the units provide to Duke's system, on both a capacity and energy basis.

A coal retirement analysis of this type is complex, as Duke must try to solve for three things at once: 1) if a unit should be retired; 2) what year it should be retired; and 3) the best replacement for that unit's

[18] DEP 2020 IRP, page 174. DEC 2020 IRP, page 175.

capacity, energy, and ancillary services. Duke's methodology fails to answer these questions at every step of the process.

Other utilities offer examples of methodologies that better achieve these goals. PacifiCorp's unit retirement analysis, for example, also had a number of steps which were presented to stakeholders as part of a public process.[19] The first step was a unit-by-unit analysis, which ranked the PacifiCorp units on both a capacity and energy basis using both the System Optimizer and Planning and Risk models. PacifiCorp then examined four different alternate retirement dates for those units that it identified as being the least economic and performed a stacked analysis for those least economic units. Finally, candidate retirements were included in the IRP portfolio development process.[20]

Similarly, NIPSCO did both a unit-by-unit and stacked retirement assessments to determine optimal coal unit retirements. Replacement resource costs were based on bids from a recent Request for Proposals (RFP) issued by NIPSCO. The utility found that accelerating coal unit retirements to 2023 and 2028 and replacement with renewable resources offered a cost-effective solution to its customers.[21]

The North Carolina Utilities Commission's previous IRP order in 2018 "[requires] Duke to provide an analysis showing whether continuing to operate each of its existing coal-fired units is the least cost alternative compared to other supply-side and demand-side resource options, or fulfills some other purpose that cannot be achieved in a different manner." The order further states that "the utilities shall model the continued operation of these plants under least cost principles, including by way of competition with alternative new resources."[22] Duke's retirement analysis fails to accomplish either of these objectives. A closer look at Duke's methodology shows that Duke does not properly account for the cost and benefits of the coal-fired capacity and energy and thus fails to produce the most "economic" retirement date for individual units and for combinations of units. The SPM avoids optimization, avoids a full economic analysis of coal units, and avoids competition with alternative resources like wind, solar, storage, and energy efficiency.

Duke's retirement analysis should be redone in a process that involves more transparency via a public process and the opportunity for stakeholders to review and comment on input assumptions and results.

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[19] PacifiCorp. December 3-4, 2018. *2019 Integrated Resource Plan (IRP) Public Input Meeting*. Available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019-irp/2019-irp-presentations-and-schedule/2018-12-03-04%20-%20General%20Public%20Meeting.pdf.

[20] *Id.* Slide 5.

[21] NIPSCO. *2018 Integrated Resource Plan.* Available at: https://www.nipsco.com/our-company/about-us/regulatory-information/irp.

[22] State of North Carolina Utilities Commission. February 2019. *Docket No. E-100 Sub. 157: Order Accepting Integrated Resource Plans and REPS Compliance Plan, Scheduling Oral Argument, and Additional Analyses.* Available at: https://starw1.ncuc.net/ncuc/ViewFile.aspx?Id=143d85de-b1e7-4622-b612-5a8c77e909d4.

3. SYNAPSE SCENARIO ANALYSIS

Synapse used the EnCompass capacity expansion and production cost model, licensed from Anchor Power Solutions, to examine two different scenarios: Mimic Duke and Reasonable Assumptions.[23]

The EnCompass model uses information about forecasted peak and energy demand along with the capital and operating costs of existing and new resources to produce an optimal, least-cost resource portfolio and generation mix. Specifically, the model does the following: (1) builds new resources when necessary to meet peak demand, plus a required reserve margin; (2) simulates economic dispatch of the various generating resources; and (3) calculates the total cost (capital and operating) of the respective resource portfolio options.

Mimic Duke scenario

Our modeling focused on two scenarios, with the first, Mimic Duke, acting as a reference to Duke's Base Case with Carbon Policy. In Mimic Duke, all modeling assumptions originate in Duke Energy Progress (DEP) and Duke Energy Carolina's (DEC) 2020 Integrated Resource Plans (IRPs). These assumptions include:

- Modeling DEC and DEP as "islands" in which the utilities do not have the ability to import energy and capacity from their neighbors;[24]
- A reserve margin of 17 percent, which can be met either through resource builds or a capacity penalty price intended to represent a proxy for short-term capacity purchases;
- Coal unit retirements based on the "most economic" retirement dates;[25]
- Replacement resource capital and operating costs for new combined cycle, combustion turbines, standalone solar, standalone battery storage, onshore wind, offshore wind, and paired solar-plus-storage resources;[26]
- Coal prices;[27]
- Effective Load Carrying Capability (ELCC)[28]

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[23] Capacity and production cost models like EnCompass are used to simulate future utility operations under different scenarios to help determine the best strategy for minimizing costs and risks while meeting all specific reliability and transmission constraints.

[24] Duke response to NCSEA Data Request 7-17.

[25] DEP 2020 IRP, page 147. DEC 2020 IRP, page 146.

[26] PSDR 3-7 Confidential – IRP Generic Unit Summary DEC 2020.xlsx.

[27] PSDR 3-4_2020 IRP_Model Inputs_CONFIDENTIAL (5).xlsx.

[28] NCCEBA DR 3-3_Renewable_Storage CTP.xlsx.

- Manually builds the solar additions identified by Duke in the IRPs between 2021 and 2025, and allowing the EnCompass model to optimize thereafter;
- A CO_2 price of $5/ton (nominal) starting in 2025 and escalating by $5/ton each year, as assumed in the Base Case with Carbon Policy.[29] This emissions price is intended to be a proxy for future CO_2 regulations at either the federal or state level.

The Mimic Duke scenario does make three updates that relate to the way in which gas-fired resources are represented in the model. The first update is to use the gas price forecasts from Horizon's Energy National Database (NDB), which includes forecast assumptions and unit level data for generating units across the United States. The base gas forecast reflects actual prices through September 2020 and settled forward prices as reported on September 30, 2020, through 2032. Beyond 2032, Horizons grows the price based on a growth trend of the Henry Hub forward in nominal dollars. Second, all new gas-fired resources offered to the model assume a retirement date of 2050 and adjust the operating life and the book life of each resource accordingly. Lastly, a gas price adder of $1.50/mmbtu was included in the operating characteristics of new combined cycle units to represent the cost of acquiring firm gas transportation rights to fuel the units.

The EnCompass model calculates the cost to operate the existing resources and adds resources as necessary over the analysis period to meet peak and energy requirements.

Reasonable Assumptions scenario

The second scenario, Reasonable Assumptions, uses the same assumptions as in the Mimic Duke scenario with only a few exceptions. This scenario uses the "Earliest Practicable" retirement dates as determined by Duke in the IRPs, while the Mimic Duke scenario uses the "Economic" retirement dates as also determined by Duke in the IRPs. Those values are shown in Table 3 in Section 2.

While the Mimic Duke scenario lets a portion of the reserve margin be met through a capacity penalty price, allowing the model to pay a penalty for capacity shortfalls in a given year, the Reasonable Assumptions scenario requires that the model build additional resources such that the actual reserve margin never falls below Duke's 17 percent requirement.

The Reasonable Assumptions scenario updates the capital and operating costs for both onshore and offshore wind based on the NREL Annual Technology Baseline (ATB), released in 2020.[30] While the Reasonable Assumptions scenario uses Duke's capital cost forecast for new solar resources, the operating costs for these units were taken from ATB 2020 as well. Costs for wind and solar resources

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[29] Duke Energy Progress (DEP). 2020. *Integrated Resource Plan 2020 Biennial Report, p. 152-153.* Available at: https://www.duke-energy.com/_/media/pdfs/our-company/irp/202296/dep-2020-irp-full-plan.pdf?la=en; Duke Energy Carolinas (DEC). 2020. *Integrated Resource Plan 2020 Biennial Report, p. 152-153.* Available at: https://www.duke-energy.com/_/media/pdfs/our-company/irp/202296/dec-2020-irp-full-plan.pdf?la=en.

[30] National Renewable Energy Laboratory (NREL). 2020. *2020 Annual Technology Baseline*. Available at: https://atb.nrel.gov/.

were levelized using Duke's financing assumptions on weighted average cost of capital and construction schedule for the different resources and offered to the EnCompass model on a $/MWh basis. This was done to allow for the model to choose resources based primarily on their energy benefit to the system rather than on the capacity need each year.

New gas additions are restricted in the Reasonable Assumptions scenario. EnCompass's optimization algorithm attempts to minimize the carrying charge associated with the addition of new resources but calculates the capital component of the revenue requirement as the sum of book depreciation, property taxes, other costs, and allowed return. This can result in a scenario in which gas capacity is added to the system, but the total revenue requirement associated with this gas scenario is higher in that scenario than in one that does not add new gas-fired resources. Synapse ran a scenario in which new gas builds were allowed with other updated inputs. The result was the addition of 1,185 MW of new gas-fired capacity and an increased revenue requirement above the Reasonable Assumptions scenario of approximately $400 million.

Lastly, Synapse used updated energy efficiency (EE) and demand side management (DSM) projections, through a combination of the savings shape of DEC and DEP programs provided in discovery and an updated forecast on future energy savings from EE/DSM. For the Realistic Assumptions scenario, we assume that Duke will ramp up its energy efficiency programs starting from 2022 from the 5-year EE plan levels and increase first year savings by 0.15 percent per year to 1.5 percent. We then assume that this level of savings will persist through the study period. Reaching a 1.5 percent savings level is a reasonable scenario for Duke because leading states in energy efficiency, such as Massachusetts and Rhode Island, have been achieving much higher savings ranging from 2 percent to 3 percent per year over the past decade while Duke's own savings have been at about 1 percent per year or less during that time frame.[31] Our analysis incorporates energy savings decay effects by taking into account Duke's own assumptions for measure lives used for its 5-year EE plans. We estimate the projected net annual savings for the Realistic Assumptions scenario is 9.6 percent of projected system load in 2035. The American Council for an Energy Efficient Economy (ACEEE) found in a recent study that the state of North Carolina could meet 18.5 percent of its forecasted need with energy efficiency by 2040[32] and confirms that 9.6 percent by 2035 is a reasonable assumption.

Synapse estimated winter and summer peak load reductions from Duke's energy efficiency programs under the Realistic Assumptions scenario based on our analysis of Duke's assumptions for hourly energy savings. More specifically, we obtained the hourly energy savings profiles that Duke used for its own IRP

[31] Historical savings data were obtained from Duke Response to NCSEA DR7-48; Savings level from leading states are available from the American Council for an Energy Efficiency Economy (ACEEE)'s State Energy Efficiency Scorecard reports, available at: https://www.aceee.org/state-policy/scorecard.

[32] American Council for an Energy Efficiency Economy. September 2020. *How Energy Efficiency Can Help Rebuild North Carolina's Economy: Analysis of Energy, Cost, and Greenhouse Gas Impacts*. Available at: https://www.aceee.org/sites/default/files/pdfs/u2007.pdf

EE analysis, and developed and applied a composite hourly load savings profile for the entire program portfolio.

In projecting program costs for the Realistic Assumptions scenario, we relied on Duke's own per unit program cost estimate for 2020 from its 5-year EE plans and kept the per unit cost constant in real dollars. Historical evidence suggests that energy efficiency programs cost tend to stay at the same level or even decrease when programs are expanded due to economies of scale.[33] A brief review of historical energy efficiency costs in different jurisdictions is presented in the appendix section. Our analysis treats program costs separately for the Home Energy Report (HER) and the rest of conventional energy efficiency programs as HER accounts for a large portion of Duke's program portfolio and the cost and measure life of HER program are very different from other programs.

A comparison of the similarities and differences between the input assumptions between the modeled scenarios is shown in Table 4**Error! Reference source not found.**, below.

Table 4. Input assumption comparison between Mimic Duke and Reasonable Assumptions scenarios

Input	Mimic Duke	Reasonable Assumptions
Carbon Constraint	None	None
DEC/DEP BA's	Merged	Merged
Imports/Exports	Not Allowed	Not Allowed
Load Forecast	From IRP	From IRP
EE/DSM	From IRP	Synapse Forecast
Solar Costs	Duke IRP Costs	Duke IRP Costs
Battery Costs	Duke IRP Costs	ATB 2020 Low
Onshore Wind Costs	Duke IRP Costs	ATB Low: Class 7
Offshore Wind Costs	Duke IRP Costs	ATB Low: Class 6
Coal Retirement	Duke Economic	Earliest Practicable
Coal Operations Costs	Duke IRP Costs	Duke IRP Costs
Coal Prices	Duke IRP Costs	Duke IRP Costs
Gas Prices	EnCompass defaults	EnCompass defaults
Planning Reserve Margin	17% (from IRP)	17% (from IRP)
Wind/Solar Capacity Credit	ELCC from Duke	ELCC from Duke
ITC Assumptions	From COVID relief bill	From COVID relief bill
New Gas Builds Allowed	Yes	No

[33] For example, see Takahashi et al. 2015. Review of TVA's Draft 2015 Integrated Resource Plan. Synapse Energy Economics. Figure 2. Available at https://www.synapse-energy.com/sites/default/files/Review-TVA-Draft-2015-IRP-14-022.pdf.

Synapse analyzed the impacts of these scenarios on DEP and DEC's joint annual capacity, annual energy mix, and CO_2 emissions. We provided details on these scenarios and impacts in Section 4, below.

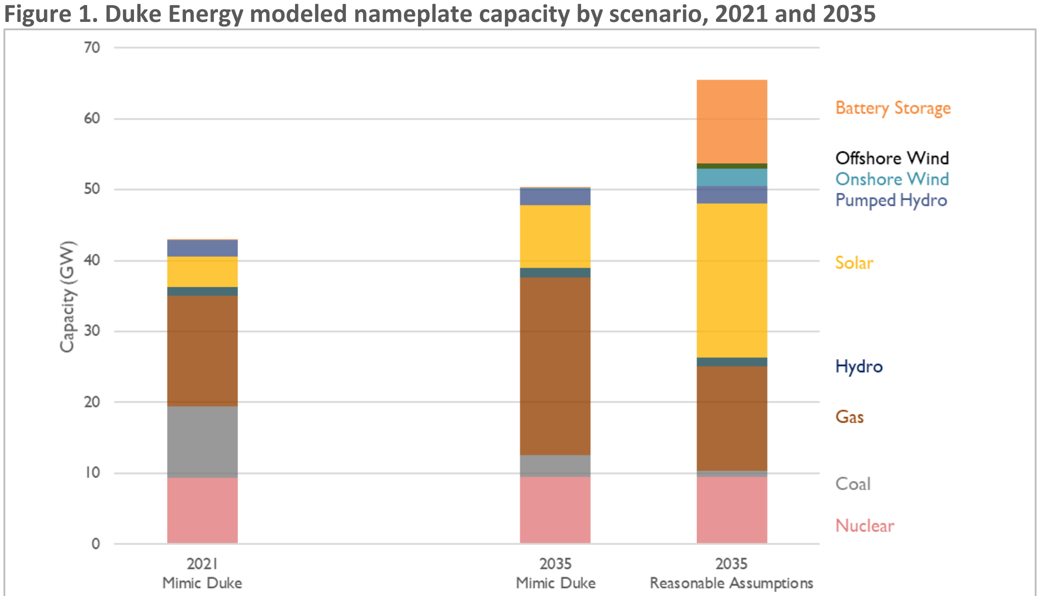
4. Electric Sector Modeling Results

The model selected new generating capacity during the analysis period to meet the 17 percent planning reserve margin in both the Mimic Duke and Reasonable Assumptions scenarios; however, the type of capacity selected differs between scenarios. The Mimic Duke scenario relies heavily on the addition of new gas-fired combined cycle and combustion turbine units, with solar PV additions of just over 3 GW. The Reasonable Assumptions scenario, on the other hand, relies on a slate of clean energy resources to meet its energy and capacity requirements that includes energy efficiency, utility-scale stand-alone solar and storage, new onshore wind, and paired solar-plus-storage resources. EnCompass model results are presented here for the entirety of Duke Energy's service territory in both North and South Carolina.

4.1. Capacity Results

Figure 1, below, shows the generating capacity in the Mimic Duke and Reasonable Assumptions scenarios in 2035 compared to Duke's actual capacity mix in 2021. As shown in Figure 1, approximately 60 percent (25.6 GW) of Duke's installed capacity in 2021 is fossil fuel-powered thermal (coal- or natural gas-fired), 22 percent (9.4 GW) of capacity is nuclear, and the remaining 18 percent (7.9 GW) comes from hydroelectric, renewable, and storage resources. By 2035, the proportion of fossil-fired resources in the Mimic Duke scenario only decreases slightly to 56 percent (28.2 GW), while renewable and storage resources have increased modestly to 25 percent (12.7 GW).

Figure 1. Duke Energy modeled nameplate capacity by scenario, 2021 and 2035

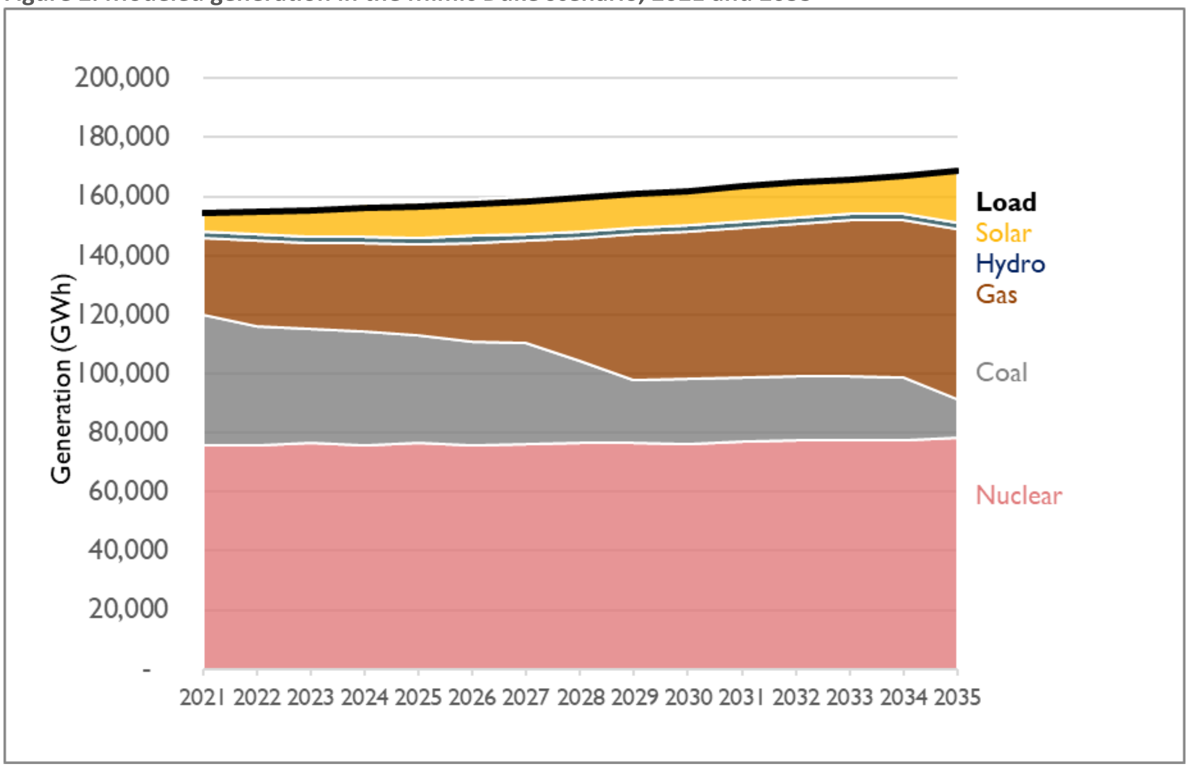


In contrast, gas and coal resources in the Reasonable Assumptions scenario drop to 24 percent (15.5 GW) of the capacity mix by 2035, and renewable energy resources comprise 62 percent (40.5 GW) of the capacity mix. Nuclear capacity remains constant in both throughout the period, though it makes up a smaller percentage of the capacity mix in 2035.

4.2. Generation Results

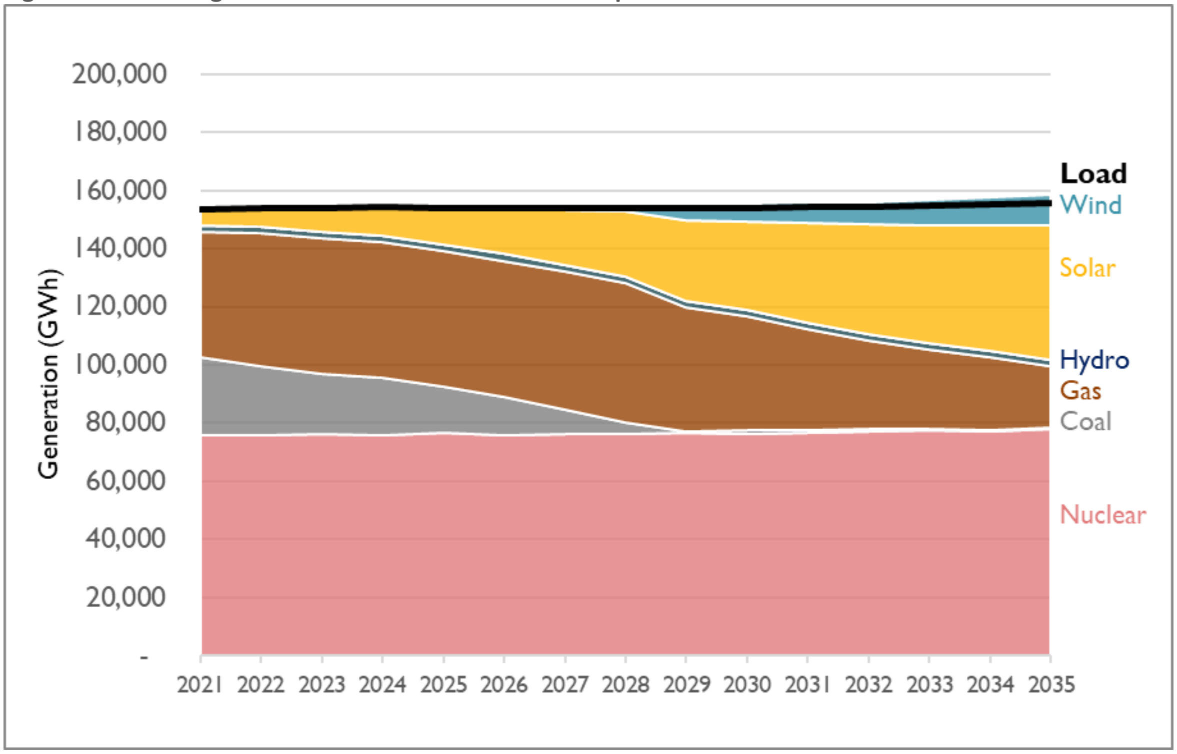
As shown in Figure 2, below, the generation mix in Duke's service territory changes slightly over time in the Mimic Duke scenario but is primarily a shift from one fossil fuel to another. Coal makes up 8 percent of generation in 2035, while natural gas generation increases over the study period to make up 34 percent of the mix in the final year of the analysis period. Renewable generation (solar, wind, and hydro) increases only slightly over the study period and makes up 12 percent of generation in 2035. Note that discharges from pumped hydro and battery storage resources are not shown in these figures.

Figure 2. Modeled generation in the Mimic Duke scenario, 2021 and 2035



In the Reasonable Assumptions scenario, shown in Figure 3, renewable generation (including hydroelectric, utility solar, onshore wind, and offshore wind) makes up 37 percent of the generation mix in 2035 as compared to 12 percent in the Mimic Duke scenario. Natural gas generation falls to 13 percent of total generation in 2035, as compared to 34 percent in the Mimic Duke scenario in that same year. By 2035, the coal has disappeared in the Reasonable Assumptions scenario. Note that generation above the load line is going to charge battery and pumped storage resources.

Figure 3. Modeled generation in the Reasonable Assumptions scenario



From a reliability perspective, under the Reasonable Assumptions scenario Duke Energy meets its hourly demand requirements in all modeled days and hours during the analysis period. The Reasonable Assumptions scenario maintains the 17 percent planning reserve margin and EnCompass projects no loss-of-load hours and sees zero hours with unserved energy.

Figure 4 and Figure 5, below, show energy generation in January 2030 —a representative winter peak day—for the Mimic Duke and Reasonable Assumptions scenarios. Duke Energy's hourly load requirements are shown by the solid line. The area between the dashed line and the solid line in the two Figures represents the time in which battery resources are being charged by solar or other resources within Duke's service territory.

Figure 4. Sample winter peak generation by fuel type, January 2030, Mimic Duke scenario

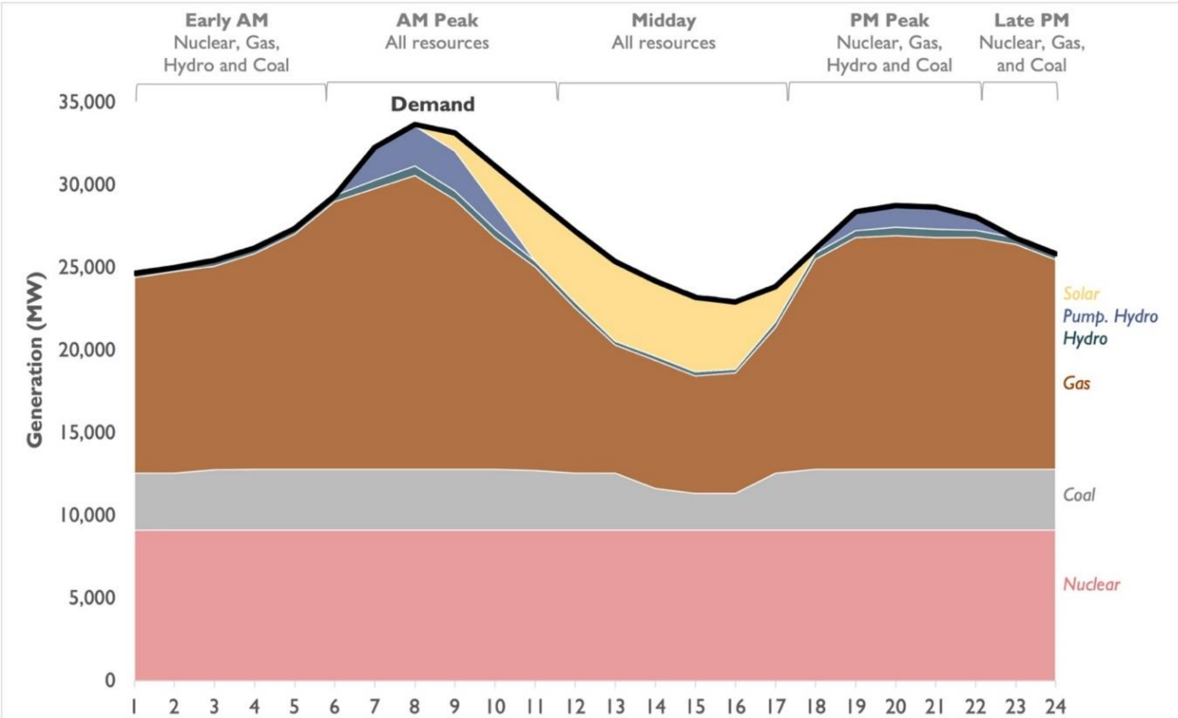
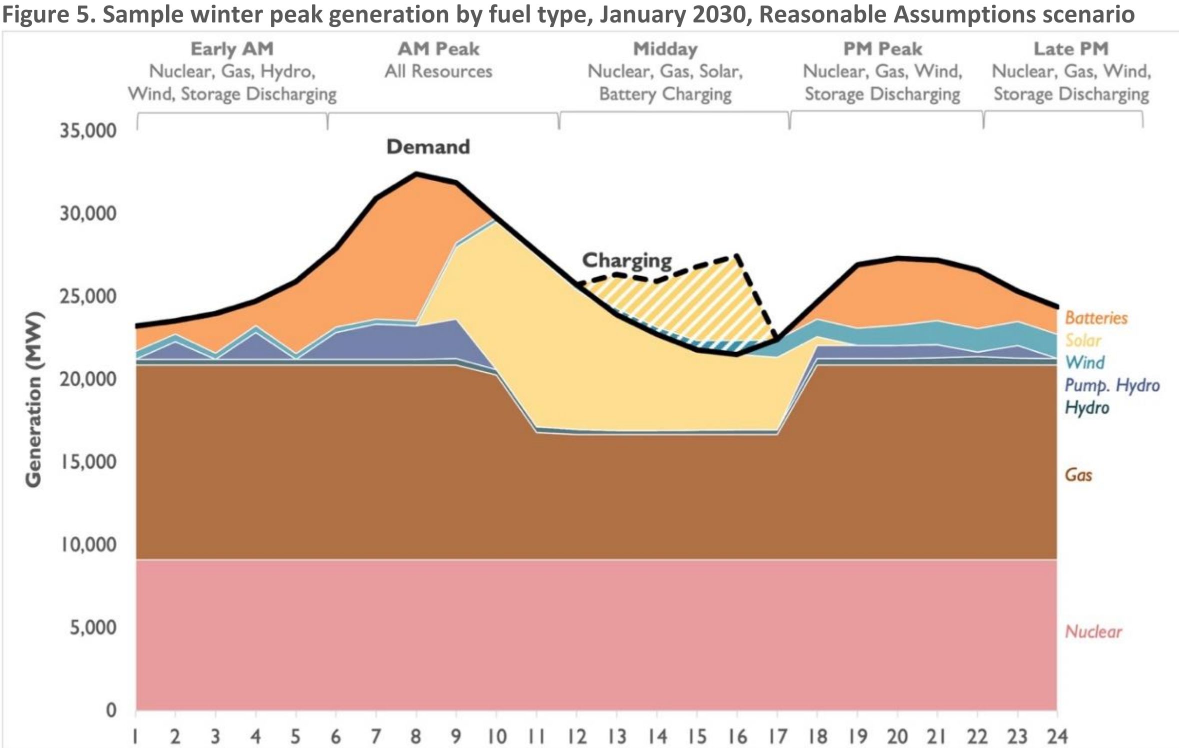


Figure 5. Sample winter peak generation by fuel type, January 2030, Reasonable Assumptions scenario



Both scenarios rely on nuclear generation as a baseload resource. The Mimic Duke scenario dispatches coal units throughout the day, and relies primarily on gas-fired generators, with small amounts of pumped storage, to meet the morning and evening peaks. Conversely, the Reasonable Assumptions scenario uses no coal, less natural gas-fired generation, and relies on a greater mix of resources. Battery capacity is charged by afternoon solar and wind generation, which allows batteries to discharge during both morning and evening hours to help meet the daily peaks.[34]

The presence of increased solar and battery capacity in the Reasonable Assumptions scenario puts less stress on the gas generators to ramp up and down over the course of the day to respond to hourly changes in demand. Generation from solar in the afternoon leads to a smaller decline in gas generation over fewer morning hours than in the Mimic Duke scenario. The discharging of stored energy from the higher number of battery resources during the morning and afternoon peaks requires a lower contribution from gas generation to meet demand in those hours. Similarly, the wind generation that exists in the Reasonable Assumptions scenario is generating during both the morning and afternoon peaks. The complementary relationship between wind and solar generation over the course of the day is clear from Figure 5. Incremental onshore wind additions in the EnCompass model were constrained such that the model could add only 100 MW per year from 2023 through 2027, then 200 MW per year from 2028 through 2031, and finally 300 MW per year from 2032 through 2035.[35] EnCompass hits that constraint in every year and would take even more onshore wind had it been available. The model adds 750 MW of offshore wind in 2029 as a complement to the solar and battery storage resources already on the system, and as a replacement for retiring coal capacity given the higher capacity credit of this resource relative to solar and storage.

4.3. Carbon Dioxide Emissions

Finally, as expected based on the substantial difference in carbon-free capacity and generation between the two scenarios, the CO_2 emissions in the Reasonable Assumptions scenario are well below those in the Mimic Duke scenario. The removal of the must-run designations for coal units immediately leads to a reduction in CO_2 emissions of 9 million tons in 2021. Though both scenarios see overall emissions decline, the gap between the two widens by the end of the period, when the Mimic Duke scenario continues to emit 35.2 million tons of CO_2 while the Reasonable Assumptions scenario emits 9.1 million tons. Figure 6 depicts this widening gap.

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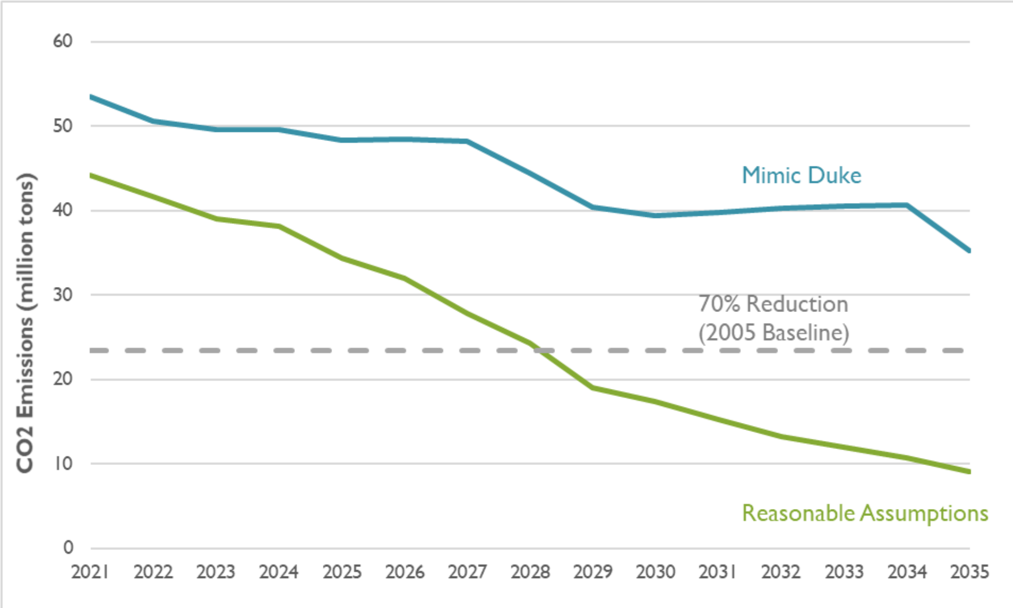
[34] The battery storage discharge that takes place in the "Early AM" hours in Figure 5 results from charging that occurred from solar and wind resources in the afternoon/early evening of the prior day in the hourly modeling run.

[35] These constraints were included to reflect the current difficulty of permitting wind in the Carolinas as well as estimates of onshore wind potential in the two states.

Figure 6. Duke Energy CO_2 emissions by year by scenario



Neither scenario enforced a binding carbon constraint. Nonetheless, we see that under the Reasonable Assumptions scenario, Duke can meet the Clean Energy Plan 70 percent emissions reduction goal before the 2030 target date and is also much closer to meeting Duke Energy's corporate goal of net-zero carbon dioxide emissions by 2050.

4.4. Revenue Requirements

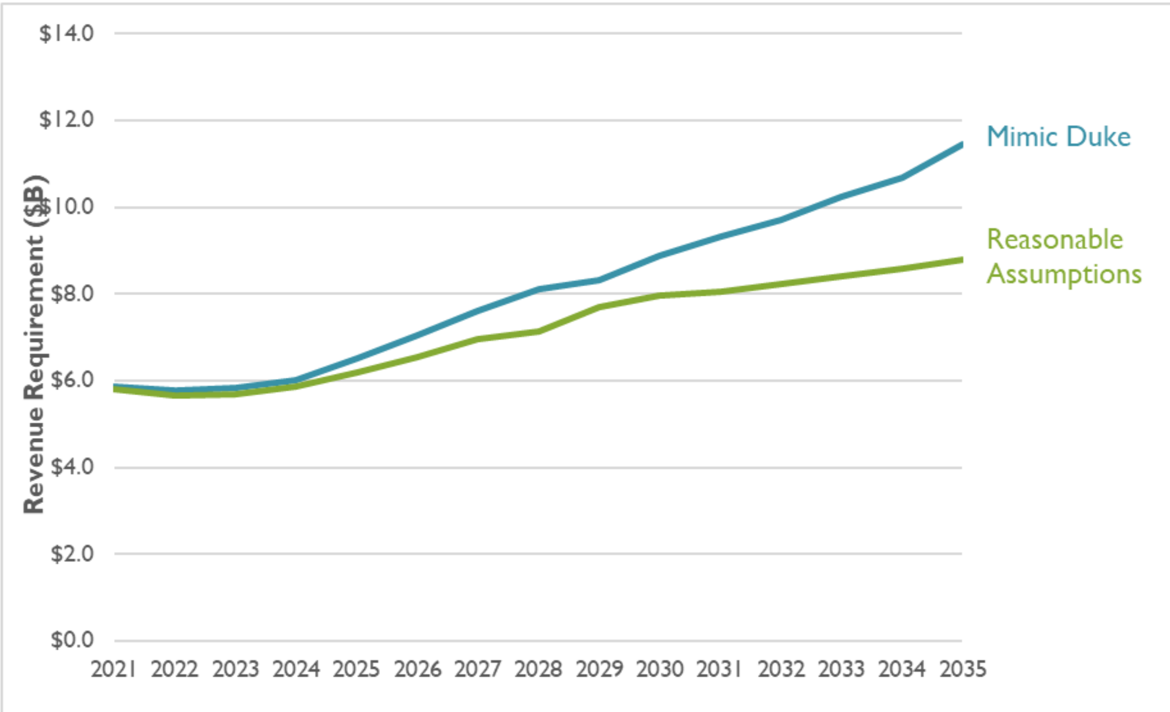
Revenue requirements are substantially lower under the Reasonable Assumptions scenario than in the Mimic Duke scenario. The cost of the Reasonable Assumptions scenario is $70.0 billion and represents a savings to ratepayers of $7.4 billion when compared to the Mimic Duke scenario. This is due primarily to the increasing competitiveness of renewable and battery storage resources as their capital costs fall over time. Total revenue requirements are also lower because of the difference in operating costs attributable to zero-variable cost renewables, and the penetration of those resources as a percent of Duke's fuel mix in the Reasonable Assumptions scenario. Those revenue requirements are shown in Table 5.

Table 5. Comparison of revenue requirements

Scenario	PVRR (Billion $)
Mimic Duke	$77.4
Reasonable Assumptions	$70.0
Delta	($7.4)

Annual incremental revenue requirements are similar between the two cases until 2024, when we begin to see a difference in the trajectory of coal unit retirements and the addition of a greater number of renewable and storage resources. At no point in time do we see a higher annual revenue requirement under the Reasonable Assumptions scenario. Those annual incremental revenue requirements are shown in Figure 7.

Figure 7. Comparison of annual incremental revenue requirements between Mimic Duke and Reasonable Inputs scenarios



Duke has noted that additional transmission investments would be needed both to retire existing coal units and to bring new renewable generators online. Interconnection costs for new renewables were included in Duke's forecasts of capital costs for renewable resources as a component of the cost of those resources in this analysis. Our analysis does not include the potential costs of other transmission investments, however, in either the Mimic Duke or the Reasonable Assumptions scenario. Each of the resource portfolios presented by Duke in the 2020 IRPs have some transmission upgrade cost associated with it, ranging from a low of $0.9 billion in the Base without Carbon Policy scenario to $8.9 billion in the No New Gas Generation scenario.

With respect to how the addition of these transmission costs might influence the revenue requirements of our scenarios, there are specific things to note. First, certain upgrade costs associated with retirement of existing coal will be the same or similar (differences might be due to a change in the timing of a retirement and the discounting of those transmission upgrade costs) between the two scenarios when specific units retire in both scenarios. Second, Duke's most expensive "No New Gas Generation" scenario has transmission costs of $8.9 billion, some of which are associated with the interconnection of 2,650 MW of offshore wind. The Reasonable Assumptions portfolio does add 750 MW of offshore wind in 2029 and would necessarily incur some costs associated with undersea transmission cables; however, the difference in PVRR between the two modeled scenarios demonstrates that new transmission could be constructed to support offshore wind development with no detrimental effect on ratepayers relative to the Mimic Duke scenario. Synapse did not examine Duke's transmission assumptions in detail and there may be a number of non-wires alternatives that were not examined by Duke and that would result in a lower total cost for transmission improvements. One of the benefits of renewables and storage is that they are smaller, more modular, and able to be sited more widely across a utility's service territory. Strategic siting of these resources on the grid could help alleviate transmission constraints and avoid some of the additional transmission benefit. Given these factors, and the delta in revenue requirements of $7.4 billion between the two scenarios modeled in this analysis, Duke could make sizable transmission investments under a Reasonable Assumptions pathway and still arrive at the same or lower total cost as in the Mimic Duke scenario.

5. CONCLUSIONS

The results of the Synapse modeling analysis show that Duke can most economically meet its customers' needs for capacity and energy through the Earliest Practicable retirement of its existing coal-fired units and their replacement with new solar, wind, and battery storage resources. This report presents one potential pathway that would meet forecasted demand while also seeking to minimize both costs and CO_2 emissions. There may be other paths that would do the same; however, there are several key conclusions that should influence any future Duke modeling analysis. First, that Duke's coal unit retirement analysis was not robust and did not accurately determine the "economic" retirement dates of its existing units. Second, that increased energy efficiency will be an essential part in the decarbonization of Duke's system, as it allows Duke to avoid the addition of more expensive supply-side resources. Third, that the addition of renewable energy resources and new battery storage capacity add value to Duke's system. Duke should attempt to maximize these additions in the short-term, which can be strategically sited to provide support to the grid and additional value to customers, over the next decade. Finally, Duke should seek to minimize additions of new gas-fired combined cycle and combustion turbines to minimize risk to customers and avoid stranded costs.

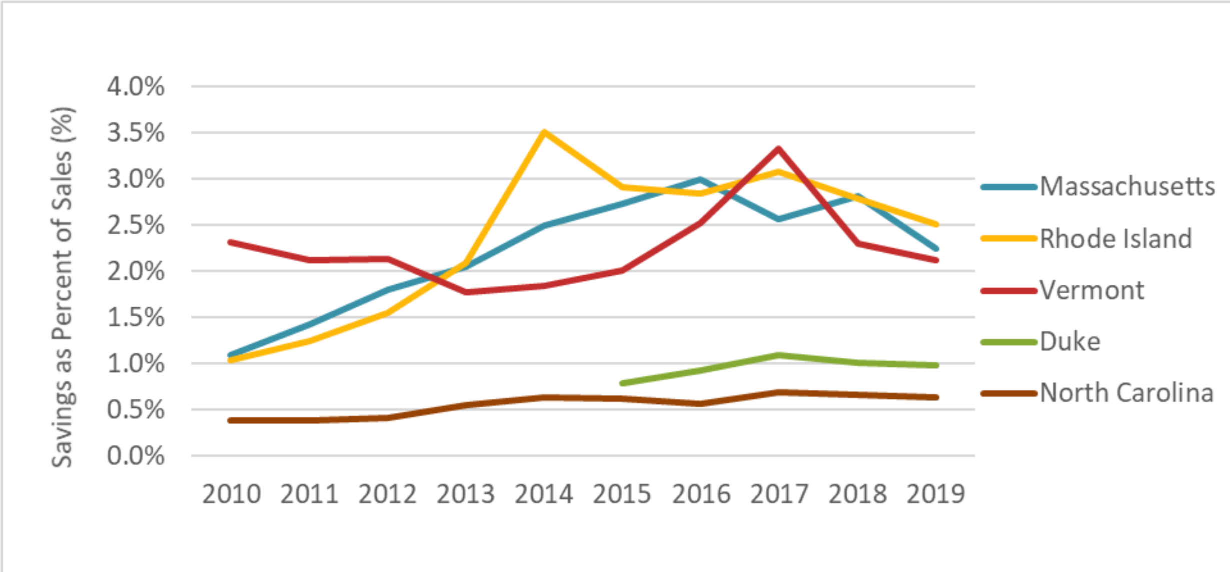
Appendix A. ENERGY EFFICIENCY METHODOLOGY

Synapse developed two distinct scenarios for Duke's energy efficiency programs in our IRP scenario modeling analysis, included in the Mimic Duke scenario and the Reasonable Assumptions scenario. The Mimic Duke scenario adopts Duke's own Base Case efficiency savings forecast included in DEP and DEC's 2020 IRPs. This scenario projects that first year savings will start at approximately 0.9 percent of the retail sales in 2020 and decline to 0.4 percent by 2035. Duke's first year energy savings data were obtained via responses to discovery.[36] The Reasonable Assumptions scenario, in contrast, assumes that first year program savings will start to increase from 2022 by 0.15 percent of retail sales per year until they reach 1.5 percent and stay at this level through the study period.

Reaching a 1.5 percent savings level is a reasonable scenario for Duke because leading states in energy efficiency such as Massachusetts and Rhode Island have been achieving much higher savings ranging from 2 percent to 3 percent per year over the past decade while Duke's own savings have been at about 1 percent per year or less during that time frame. Figure 8 presents historical first year savings for Duke (combining DEP and DEC's programs), North Carolina as well as three leading states in energy efficiency. Compared to these leading states, Duke and other utilities in North Carolina have missed a substantial amount of energy savings over the past decade. However, this also means that there are plenty of untapped energy savings potential available for Duke.

[36] Data file "NCSEA DR7-46 Part F.xlsx" obtained from Duke.

Figure 8. Historical First Year Savings: Duke and North Carolina vs. Leading States



Source: ACEEE's State Energy Efficiency Scorecard reports; data files "NCSEA DR7-48 DEP Projection and True up Filings 2015-2019.xlsx" and "NCSEA DR7-48 DEC Projection and True up Filings 2015-2019.xlsx" obtained from Duke.

Figure 9 below compares projections of annual net energy savings between Mimic Duke and Reasonable Assumptions. Net annual energy savings represent total annual cumulative energy savings that are in effective in each year, taking into account energy savings decay effects.[37] The net annual savings for 2035 under Mimic Duke are approximately 2,248 GWh for DEP and 4,120 GWh for DEC in 2035.[38] The Mimic Duke scenario, for the two jurisdictions combined, projects 6,370 GWh of net annual savings for 2035 or 3.7 percent of the projected system load. The Reasonable Assumptions scenario, on the other hand, projects about 16,500 GWh of net annual savings for 2035 or 9.6 percent of the projected system load. This is slightly over 2.5 times more than the savings projected under the Mimic Duke scenario.

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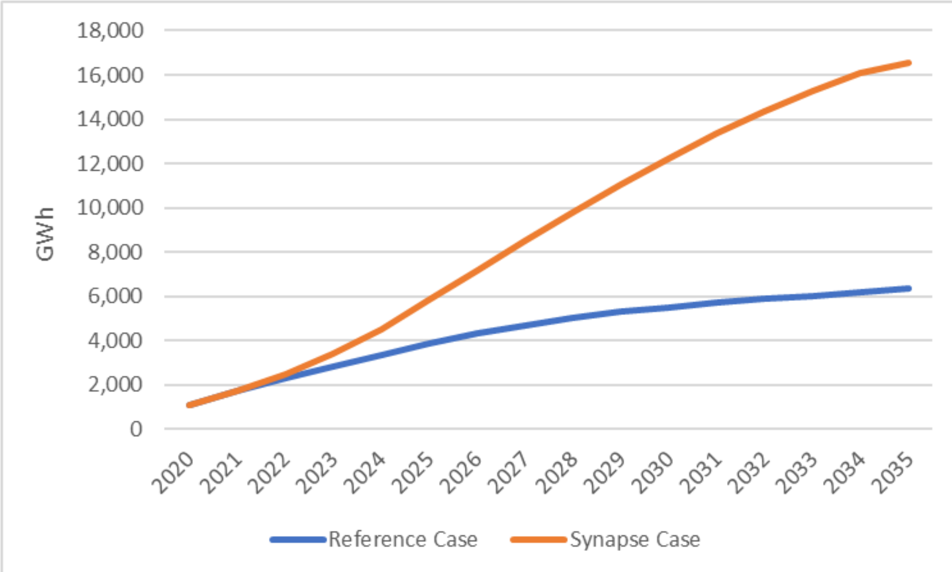
[37] Duke's measure live estimates range from 1 year for the Home Energy Report program to 20 years for insulation and some HVAC measures with an average measure life of 7 to 8 years. We obtained Duke's measure life data sets used for DEP and DEC's 5-year EE plans through our data request NCSEA DR9-3a.

[38] Duke Energy Progress, 2020, page 70; Duke Energy Carolinas, 2020, Page 69.

Figure 9. Projection of Net Annual Energy Savings: Mimic Duke vs. Reasonable Assumptions (GWh)



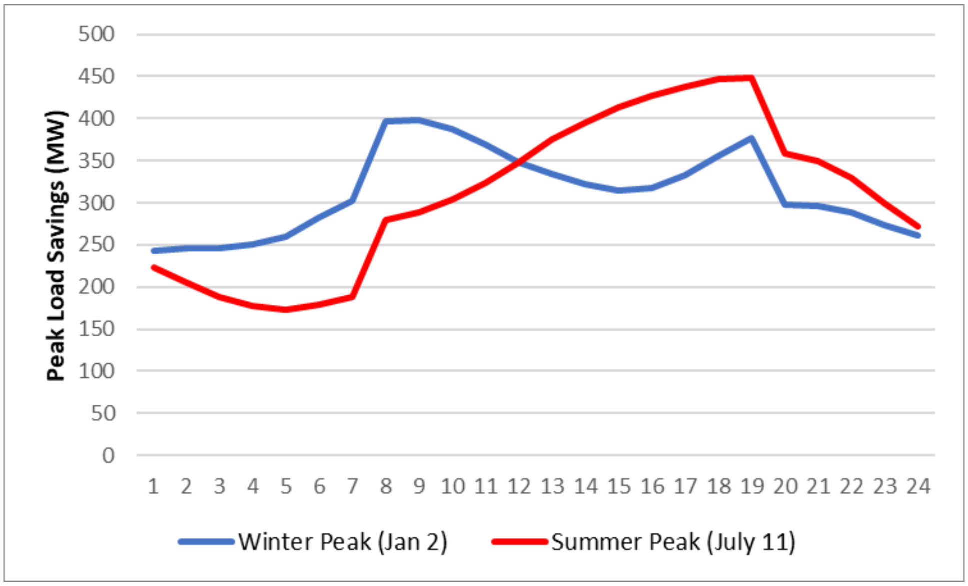
Source for the Mimic Duke scenario: Duke Energy Progress, 2020, Integrated Resource Plan 2020 Biennial Report, page 70; Duke Energy Carolinas, 2020, Integrated Resource Plan 2020 Biennial Report, page 69.

For the purpose of projecting net annual savings and program costs under the Reasonable Assumptions scenario, we projected savings and costs separately for the Home Energy Report (HER) program and for the traditional energy efficiency programs because the HER program accounts for a large portion of Duke's program portfolio and the cost and measure life of HER program are very different from other programs. Historically the HER program savings accounted for about 30 to 40 percent of the total residential program savings, but Duke estimates the HER savings share increases to 46 percent to 49 percent in its DEC and DEP EE 5-year plans. Given these levels of savings are already at a very high level for the HER-type program compared to other jurisdictions, we assumed that the annual savings level from this program stay at the 5-year EE plan level through the study period.

Synapse estimated winter and summer peak load reductions from Duke's energy efficiency programs for the Reasonable Assumptions scenario by adopting Duke's assumptions for measure level hourly energy savings. More specifically, we obtained the hourly energy savings profiles that Duke used for its own IRP EE analysis that differ by measure type and developed a composite hourly load savings profile for the entire program portfolio for Duke's 5-year EE plans.[39] We then applied this portfolio level savings profile to the projected annual energy savings for the Mimic Duke scenario and for the Reasonable Assumptions scenario in order to estimate winter and summer peak load reductions. Figure 10 shows illustrative hourly load savings as winter and summer peak savings.

[39] NCSEA DR7-59c – DEC Savings Shapes.xlsx and NCSEA DR7-59c – DEP Savings Shapes.xlsx.

Figure 10. Estimated Composite Hourly Load Savings for Duke's Energy Efficiency Programs in 2022 under the Reasonable Assumptions scenario



Source: Synapse calculations

Synapse relied on DEP and DEC's 5-year energy efficiency program forecasts to estimate program costs for the first five years, and then estimated program costs in the following years through 2035 based on (a) the per unit program cost data (in dollars per first year MWh savings) from the 5-year program plans, and (b) the first year program savings estimates for those years that we obtained through our data request.[40] The per unit costs of saved energy used in our analysis are presented in Table 6 below separately for the Home Energy Report (HER) program and other EE programs by DEC and DEP. Finally, Synapse amortized the program costs for DEP's programs over a 3-year period with the company's weighted average cost of capital.[41]

Table 6. Cost of Saved Energy ($ per First Year Savings)

	DEC	DEP
HER program	0.04	0.05
Other EE programs	0.26	0.31

Source: NCSEA DR7-49 - 2020 IRP 5-year plan.xlsx

For projecting program costs for the Synapse Case, we relied on Duke's own per unit program cost estimate for 2020 from its 5-year EE plans and kept the per unit cost constant in real dollars. Historical evidence suggests that energy efficiency programs

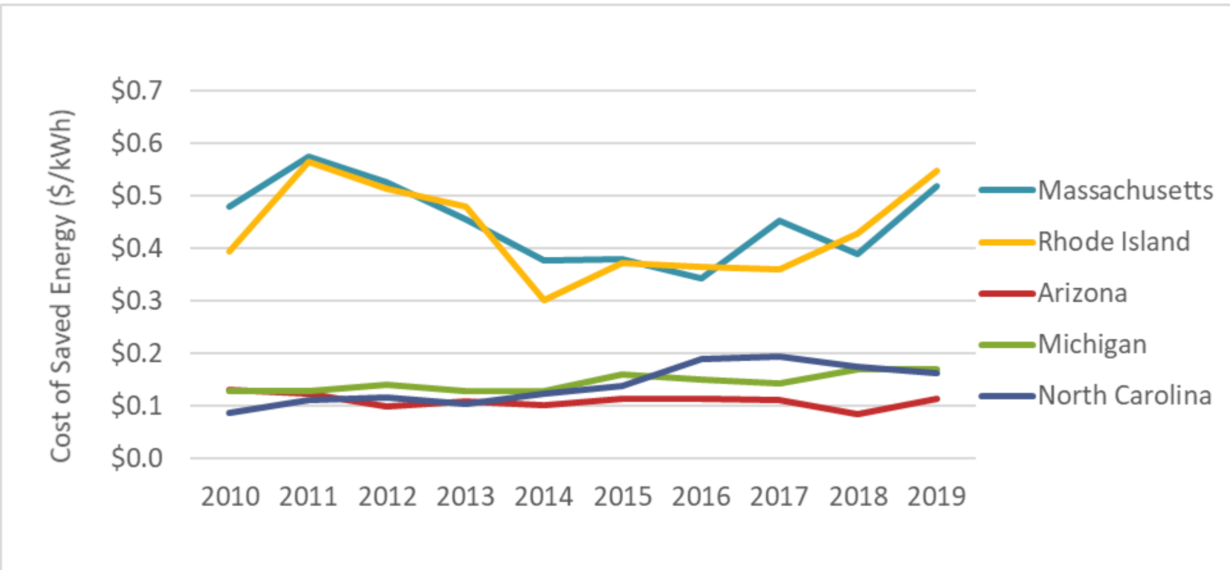
[40] NCSEA DR7-46 Part F.xlsx.

[41] North Carolina Utilities Commission. 2020. Order Approving Revisions to Demand-Side Management and Energy Efficiency Cost Recovery Mechanisms. Docket No. E-2, Sub 931 and E-7, Sub 1032.

cost tend to stay at similar levels or sometimes even decrease when program scales are expanded due to economies of scale.[42]
Figure 11 and Source: ACEEE's State Energy Efficiency Scorecard reports

Figure 12 presents costs of saved energy by selected states including two top states in energy efficiency programs (Massachusetts and Rhode Island), two mid-level leading states (Arizona and Michigan) (at a savings level of 1.5 percent), and North Carolina. As can be seen in these figures, the costs of saved energy have been mostly either flat or slightly decreased over several years from 2011 to 2014 to 2016 for Massachusetts and Rhode Island when they increased energy saving levels. These historical data support our assumption of keeping the cost constant for the Reasonable Assumptions scenario where we assumed first year savings increase to 1.5 percent per year.

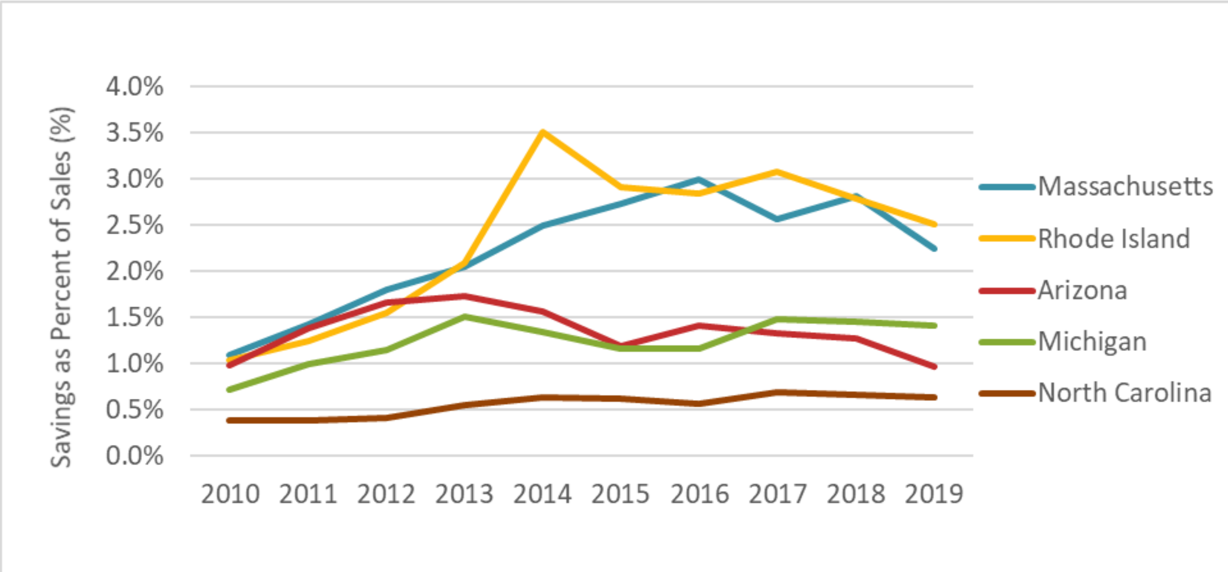
Figure 11. Costs of Saved Energy for Selected States from 2010 to 2019 ($ per kWh first year)



Source: ACEEE's State Energy Efficiency Scorecard reports

[42] For example, see Takahashi et al. 2015. Review of TVA's Draft 2015 Integrated Resource Plan. Synapse Energy Economics. Figure 2. Available at https://www.synapse-energy.com/sites/default/files/Review-TVA-Draft-2015-IRP-14-022.pdf.

Figure 12. First Year Savings Comparison for Selected States from 2010 to 2019



Source: ACEEE's State Energy Efficiency Scorecard reports

Projected energy efficiency program costs are presented in Table 7 (see next page) for both the Mimic Duke and the Reasonable Assumptions scenarios. Program costs start around $170 million for both scenarios. Under Mimic Duke, the program costs are projected to increase to $250 million in 2025 and decline to $150 million by 2035. Under Reasonable Assumptions, the program costs are projected to increase to $746 million by 2035.

Table 7. Projected Energy Efficiency Program Costs by Scenario ($000)

	Reference Case			Synapse Case		
	DEC	DEP	Total	DEC	DEP	Total
2020	27,928	145,867	173,795	27,928	145,867	173,795
2021	54,787	168,034	222,821	54,787	170,991	225,779
2022	81,586	193,945	275,532	89,894	237,612	327,506
2023	79,999	188,485	268,484	105,591	289,873	395,464
2024	79,761	186,410	266,171	131,122	353,041	484,163
2025	78,456	192,343	270,799	157,822	419,365	577,187
2026	76,453	187,203	263,656	180,532	447,294	627,826
2027	71,851	178,153	250,003	195,619	466,948	662,567
2028	65,955	167,586	233,541	202,520	478,588	681,108
2029	58,689	155,421	214,111	206,221	487,252	693,473
2030	51,107	142,703	193,810	210,117	496,139	706,256
2031	43,526	132,073	175,599	214,172	505,295	719,467
2032	37,440	126,048	163,489	218,319	514,537	732,857
2033	33,970	123,696	157,666	222,625	524,175	746,800
2034	32,937	123,920	156,857	227,050	533,916	760,965
2035	32,988	125,369	158,357	231,699	544,283	775,983