North Carolina

Clean Energy Plan

Transitioning to a 21st Century Electricity System

Supporting Document

PART 5

Energy & Emissions Modeling

DRAFT

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NORTH CAROLINA
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Preface

This is a draft of North Carolina's Clean Energy Plan (CEP). The public comment period is open from August 16, 2019 through September 9, 2019. Comments may be submitted online at https://deq.nc.gov/cleanenergyplan.

The Clean Energy Plan was written by the Department of Environmental Quality as directed by Executive Order No. 80..[1] DEQ was tasked with the creation of a CEP to encourage the use of clean energy resources and technologies and to foster the development of a modern and resilient electricity system. The purpose of the CEP is to outline policy and action recommendations that will accomplish these goals. The CEP is made up of the main document titled *Policy and Action Recommendations* and six supporting documents.

Part 1: Energy Sector Profile and Landscape

Part 2: North Carolina's Energy Resources

Part 3: Electricity Rates and Energy Burden

Part 4: Stakeholder Engagement Process

Part 5: Energy and Emissions Modeling

Part 6: Clean Energy Jobs and Economic Outlook

The purpose of this section (Part 5: Energy and Emissions Modeling) is to provide an overview of the modeling efforts that were conducted by as part of the CEP development. For more information, see the Modeling Summary.

[1] https://files.nc.gov/ncdeq/climate-change/EO80--NC-s-Commitment-to-Address-Climate-Change---Transition-to-a-Clean-Energy-Economy.pdf

Modeling Summary

Governor Roy Cooper's Executive 80 charged DEQ with developing a Clean Energy Plan (CEP) to explore options to increase clean energy resources as well as reduce GHG emissions. Part of the CEP process was to identify programs, policies and actions North Carolina could take to achieve its goals and to study their impact using electricity sector modeling tools.

This section discusses predictive modeling completed by four organizations that voluntarily analyzed the North Carolina electric sector. Additional analysis was also completed by the DEQ. The key "metrics of success" listed in Table ES-1 below were identified by stakeholders during the CEP public engagement process. Modeling outputs included data about these key metrics. For this report, 2030 was used as a target year for modeling results, although models do have additional data for future years beyond 2030.

Table MS-1: North Carolina Stakeholder Metrics of Success Applied to Modeling Analysis

Stakeholder Metrics of Success
Decrease the use of fossil fuels for electricity generation
Increase the use of clean energy resources for electricity generation
Limit the use of electricity imported from neighboring states to meet electricity demand
Decrease emissions of carbon dioxide (CO_2)[2]
Limit the impact to electricity rates, especially for low income communities, from increasing electricity generation using clean energy resources
Maintain a least-cost approach to selecting new resources to meet future demand

There are multiple approaches, both clean energy technology driven and carbon policy driven, to achieve CO_2 emissions reductions. Modeling projected impacts to the electricity sector from applying five different program and polices scenarios. These scenarios are:

1) Accelerate Coal Retirements,
2) Enact a Clean Technology Standard or Expand REPS[3],
3) Join a Trading Program,
4) Impose a Carbon Cap, and
5) A hybrid of Join a Trading Program and Enact a Clean Technology Standard

2030 Modeling Results

Table MS-2 presents a summary of the results from the modeling exercises. These results give an estimate of how CO_2 emissions from North Carolina's electric power sector could change between 2005 and 2030 from adopting the programs and policies discussed above.

Table MS-2: Projected CO_2 Emissions Reductions under Various Program and Policies

[2] Electricity sector modeling only estimates emissions of CO_2 since it represents 99% of the greenhouse gas emissions from fossil fuel combustion in the electricity sector.
[3] North Carolina's Renewable Energy and Energy Efficiency Standard (REPS) enacted in 2007.

Scenario Type	Scenario Name	CO_2 Emission Reductions from 2005 to 2030	Projected 2030 Emissions Level
Clean Energy Driven	Accelerate Fossil Retire	68%	25.3 MMT
	Clean Technology Standard or Expand REPS	58%	33.5 MMT
Carbon Policy Driven	Join Trading Program	48%-57%	34.0-41.6 MMT
	Carbon Cap at 25 MMT	68%	25.0 MMT
Hybrid	Trading Program + Clean Tech	62%	29.8 MMT

COAL RETIREMENT AND CARBON CAP SCENARIOS HAVE THE POTENTIAL TO REDUCE EMISSIONS 68% FROM 2005

Scenarios modeling accelerating coal retirements and a carbon cap result in substantial decreases in coal generation. Since these scenarios also limited a shift to imports to fill in for coal retirements, this leads to substantial increases in renewable energy (RE) generation, approximately 17,000 to 20,000 GWh over the economic case. This puts total RE generation at approximately 33,000 GWh or 25% of total projected generation in 2030. These scenarios have the potential to reduce CO_2 emissions by 68% from 2005 levels by 2030.

Scenarios modeling a Clean Technology Standard have the potential to meet many of the metrics of success but do not reduce CO_2 emissions as much as those accelerating coal retirements or a carbon cap noted above. The models project Clean Energy Standard RE capacity expanding by over 8,500 MW. Electricity generation from RE resources more than doubles over the economic case to approximately 18,000 gigawatt-hours (GWh) by 2030. But these scenarios use fossil fuels and imports to supplement RE resources. Therefore, CO_2 emission reductions are more modest than scenarios which limit fossils fuel use. The models project 2030 CO_2 emissions to decrease by approximately 58% from 2005 levels under these scenarios. These scenarios have the potential to decrease electricity prices projected for 2030 since the operating costs for RE are substantially less than for fossils fuel resources.

The scenario that is produced the lowest range in emissions reductions is for North Carolina to join a trading program. This is because it does not create additional economic incentives to decrease coal generation over the current market trends. Low natural gas prices are already causing coal retirements and decreased generation from coal. Depending on its design, a trading program may increase imported electricity generation. CO_2 emissions reductions may not be significant if fossil fuel generation shifts to imports rather than in state RE resources. A more through evaluation should be conducted to examine the economic and environmental benefits of this policy option.

The hybrid combination of a trading program and a clean technology standard creates additional incentives shifting fossil fuel generation to RE and EE resources rather than importing generation, which may occur under trading program only approaches. These combined requirements result in 62% CO_2 emission reductions from 2005 levels by 2030.

NORTH CAROLINA CAN CONTINUE TO APPLY CLEAN ENERGY DRIVEN PROGRAMS TO ACHIEVE LOWER EMISSIONS.

Historically, North Carolina has reduced GHG emissions by retiring uneconomic coal plants and implementing a clean technology standard that includes both RE and EE. These are clean energy and market driven approaches which create incentives to build both a least cost and cleaner electricity system while also providing economic and public health benefits. This modeling synthesis indicates that North Carolina can continue to apply these approaches to achieve our goals for a cleaner electricity system.

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Energy and Emissions Modeling

1. Purpose of Electricity Sector Modeling

This section of the Clean Energy Plan is a synthesis of the electricity sector predictive modeling exercises that were voluntarily conducted by four different organizations. It discusses the modeled impact on electricity generation from the proposed adoption programs or policies designed to increase the use of clean energy resources in North Carolina. Each organization conducted their own modeling exercises with limited input on the 2017 base year assumptions from the DEQ. A more complete discussion of each modeling tool, basic assumptions, scenarios modeled, and results are provided by each organization in the attached Appendix: Electric Power Sector Modeling Reports Provided by each Organization.

Modeling tools for the electricity sector are commonly used by states and federal agencies to understand the effect of policies like environmental standards and air pollution trading programs, and other initiatives, such as energy efficiency (EE) programs.[4] For the CEP, the use of predictive modeling helps the people of North Carolina understand the impacts to the electricity sector from various actions that the State could choose to take. DEQ's synthesis of the modeling allows the reader to visualize the directional outcome of each scenario, rather than having to understand individual modeling results. It also highlights the changes to the existing system that will be necessary to achieve a desired, cleaner, electricity generation fleet by 2030.

North Carolina utilities are required to build and operate a least cost electricity system.[5] The synthesis developed by DEQ shows the changes in electricity generation between a future year least-cost system (called the economic case) and the application of various policies or programs that have specific clean energy/carbon reduction incentives or requirements. The changes are evaluated for North Carolina's key "metrics of success". These metrics of success are based on the values and recommendations brought forward by stakeholders during the public engagement process. These six metrics are listed in Table 1.

Table 1: North Carolina Stakeholder Metrics of Success Applied to Modeling Analysis

Stakeholder Metrics of Success
Decrease the use of fossil fuels for electricity generation
Increase the use of clean energy resources for electricity generation;
Limit the use of electricity imported from neighboring states to meet electricity demand
Decrease emissions of carbon dioxide (CO_2).[6]
Limit the impact to electricity rates, especially for low income communities, from increasing electricity generation using clean energy resources
Maintain a least-cost approach to selecting new resources to meet future demand

[4] U.S. Environmental Protection Agency. "EPA's Power Sector Modeling Platform v6 using IPM May 2019 Reference Case". July 1, 2019. Accessed at https://www.epa.gov/airmarkets/epas-power-sector-modeling-platform-v6-using-ipm-may-2019-reference-case.

[5] North Carolina General Statute 62-2(a)(3)

[6] Electricity sector modeling only estimates emissions of CO_2 since it represents 99% of the greenhouse gas emissions from fossil fuel combustion in the electricity sector.

The DEQ does not intend to use any of the modeled results to quantify the impact of various programs or policies for use in a regulatory impact analysis. A more controlled and detailed analysis would be necessary to further understand and quantify the specific impacts due to application of programs or policies.

2. Electricity Sector Modeling Overview

Electricity sector projection models start with the capacity, generation, and transmission in a historic base year for a specific region or the entire US. Assumptions regarding planned changes to the system, future changes in electricity demand, and future costs are used as inputs to the model. Unit level characteristics for each power plant, such as fuel type, size, age and environmental controls, are also input into the model. Parameters for new technologies, regulations, programs and policies are applied to the system. The models consider a number of factors including:

- Planned retirements and new units coming online,
- Cost of operating existing power plants,
- Cost of building and operating new power plants,
- Changes in electricity demand (base load and peak demand),
- Fuel availability and cost,
- Availability and cost of new technologies such as batteries,
- Transmission, dispatch and reliability constraints,
- Electricity imports and exports across regions, and
- Environmental rules and programs that are planned to go into effect.

The models then optimize a least cost regional electricity system for a future year. Outputs of the model include projections of capacity builds, generation, transmission, emissions and costs for the optimized system.

As stated earlier, the models are designed to build and dispatch the least-cost system. However, the models can also impose various proposed program, policy, or other scenarios on the electricity sector such as, a carbon tax, higher fuel costs, proposed environmental regulation, and renewable energy targets. The models project parameters such as future year capacity, generation, emissions and costs at the plant level. The models have varying levels of complexity and methods for projecting the outcomes from applied assumptions and scenarios.

An important factor in modeling North Carolina's electricity sector is that the territory for Duke Energy Carolina (DEC) and Duke Energy Progress (DEP) also includes a large portion of South Carolina. In addition, Dominion Energy, Inc., (Dominion) which provides most of its electricity to Virginia, also includes a small portion of North Carolina. DEC, DEP and Dominion operate their multi-state territories as one system; therefore, it is difficult to separate out the modeled impact on the joint territories to just North Carolina. In addition, DEC and DEP are "vertically integrated", meaning the utility owns all levels of the supply chain: generation, transmission and distribution. This makes the electricity market less transparent and more difficult to model, especially impacts to electricity prices.

In addition, the models are focused on utility scale power generation and may not have methods to capture the more complex distributed energy resource market and the role this sector may play in the future, especially when coupled with electricity storage.

3. Organizations Providing Electricity Sector Modeling Results

The NC Department of Environmental Quality was fortunate to have independent, voluntary, electricity sector modeling analysis conducted by outside organizations with considerable expertise. Organizations providing analysis and the modeling tools that they used are noted in Table 2.

Table 2: Organization and Modeling Tool for Electricity Sector Modeling

Organization	Model Used
Natural Resources Defense Council (NRDC)	Integrated Planning Model (IPM) written by ICF[7]
Resources for the Future (RFF)	Haiku[8]
NC State University (NCSU)	Tools for Energy Model Optimization and Analysis (TEMOA)[9]
Georgetown Climate Center (GCC)	IPM

The DEQ's Division of Air Quality evaluated future year estimates for one scenario, accelerated coal retirement. These estimates relied on two information sources: 1) the electricity sector projection prepared for the North Carolina Greenhouse Gas Inventory (1990-2030);[10] and 2) the 2028 reference case modeled using the Eastern Regional Technical Advisory Committee (ERTAC)'s EGU Forecast Tool.[11] This analytical approach is included in the DEQ's synthesis.

The North Carolina Sustainable Energy Association (NCSEA) also submitted results from modeling that was conducted prior to the start of the CEP effort. Therefore, this modeling exercise was not able to incorporate NC DEQ's baseline assumptions that were developed for this effort. As a result, it was difficult to compare the outcomes from this modeling exercise to the other modeling efforts. The results of the NCSEA study were submitted to the North Carolina Utilities Commissions (NCUC) as comments in response to Duke Energy's 2018 Integrated Resource Plans (IRPs).[12]

[7] ICF (2019). Integrated Planning Model (IPM). Retrieved from https://www.icf.com/technology/ipm
[8] Resources for the Future (2019). Haiku Electricity Market Model. Retrieved from https://www.rff.org/publications/reports/the-rff-haiku-electricity-market-model/
[9] NCSU TEMOA Team (2019). Tools for Energy Model Optimization and Analysis. Retrieved from http://www.temoaproject.org/people/
[10] North Carolina Greenhouse Gas Inventory (1990-2030), North Carolina Department of Environmental Quality, Division of Air Quality, January 2019, accessed at https://deq.nc.gov/energy-climate/climate-change/greenhouse-gas-inventory.
[11] ERTAC (2019). EGU Forecast Tool. Eastern Regional Technical Advisory Committee (ERTAC). Retrieved from https://www.marama.org/2013-ertac-egu-forecasting-tool-documentation
[12] NCSEA (2018). "NCSEA's Initial Comments On Duke Energy Carolinas, LLC And Duke Energy Progress, LLC's Integrated Resource Plans". North Carolina Sustainable Energy Association (NCSEA). Submitted to the NCUC in Docket No. E-100, Sub 157. March 7, 2019.

Lastly, the US Environmental Protection Agency also provided modeling results from the running several of their modeling tools. However, these tools are not included in the synthesis since the results are either at a higher level than the other modeling tools or considered preliminary at the time this report was published.

4. Projections Based on the Economic Case

The modeling scenarios included in DEQ's CEP started with a 2016 base year. This is an important consideration given that our electricity sector has undergone a transformation, retiring coal plants and replacing them with natural gas generation between 2010 and 2014. In addition, the DEQ developed a schedule of planned, firm retirements and new capacity additions expected by 2030 to use as inputs to the models. The DEQ also provided information on the conversion of six coal boilers to duel fuel (coal and natural gas). However, only one model was able to incorporate this into the modeling methodology. This includes the retirement and replacement of the Duke Energy Asheville coal plant with NGCC and solar PV by 2020 and the full retirement of the Duke Energy GG Allen coal plant by 2028.[13]

Current environmental and energy regulations and policies that impact North Carolina were represented in the modeling including REPS and the House Bill 589, which increase the amount of solar PV in North Carolina by 2021.[14] There was no regulation of carbon included since EPA's Clean Power Plan was expected to be replaced with a much less stringent rule by mid-2019.

Each organization modeled a reference case based on an economic, least-cost approach, which this document refers to as the "economic case". Under this case, economic drivers build or retire power plants using various energy resources based on fuel prices, technology installation prices, and other factors obtained from the modeling tool inputs and assumptions. It also decides which plants will "dispatch" (generate electricity over a given time period) based on the operating cost and generation characteristics of each plant type, and other factors. Table 3 presents the average results from each of the economic cases modeled.

The table indicates that economics drives the retirement of about 3,000 MW of coal capacity by 2030 (30%). To offset this capacity, the models build (on average) about 4,000 MW of natural gas combined cycle (NGCC) capacity and about 1,000 MW of natural gas single cycle capacity. In addition, economics drive a shift in electricity generation between 2017 and 2030. On average, the models project that coal generation will decrease by approximately 40% and NGCC generation will increase by 30%. Overall fossil generation decreases 7%, from about 73 TWh to 68 TWh. As a result, 2030 CO_2 emissions from the electricity sector are estimated to drop 8% from 2017 levels (39% from 2005 levels).

[13] For GG Allen, three coal units retire in 2024 and two additional units retire in 2028.
[14] See Energy Policy Landscape for a description of House Bill 589.

Table 3: Capacity and Generation for 2017 and Average of Economic Case Modeling Results

Resource	2017 Capacity (MW)	2030 Average Economic Capacity (MW)	2017 Generation (GWh)	2030 Average Economic Generation (GWh)
Nuclear	5,294	6,611	42,374	43,651
Coal	10,170	7,180	34,460	21,518
Natural Gas Combined Cycle	5,359	11,080	34,446	44,409
Natural Gas Combustion Turbine	6,861	7,173	4,144	2,094
Oil Combustion Turbine	327	0	247	0
Hydroelectric	1,980	2,089	3,818	4,474
Hydroelectric Pumped Storage*	68		NA	NA
Solar Photovoltaic	3,290	9,082	5,114	14,486
Onshore Wind Turbine	208	178	471	653
Energy Efficiency**			NA	11,478
Battery Storage *	1	441	NA	NA
Biomass	166	269	2,813	547
Other		2,659	582	1,322
Total	**33,724**	**46,763**	**128,469**	**133,152**
Total Fossil	**22,717**	**25,433**	**73,297**	**68,021**
Imports			**13,173**	**14,313**

*Storage resources do not generate electricity.
** EE represents avoided generation and cannot be measured directly

North Carolina's House Bill 589 (HB589) requires Duke Energy to procure about 2,660 MW of solar PV by 2021.[15] Combining this with the existing capacity, North Carolina's installed solar PV capacity will be approximately 6,000 MW by 2021. The average of the economic modeling exercises shown in Table 3 indicates that it is economical for North Carolina to go beyond HB589 and build approximately 3,000 MW of additional solar PV between 2021 and 2030. This level of solar PV capacity almost triples solar generation from the amount generated in 2017.

The economic projection of electricity capacity retirements and builds for North Carolina is similar to national projections. Figure 2 presents the projected retirement and growth of both fossil fuel and renewable capacity from 2018 to 2050 for the US in gigawatts (GW) from the 2019 Annual Energy Outlook.[16] As discussed previously, projections are generally only reliable in the short-term, about ten years in the future.

[15] Session Law 2017-192, "An Act to Reform North Carolina's Approach to Integration of Renewable Electricity Generation Through Amendment of Laws Related to Energy Policy and to Enact the Distributed Resources Access Act," July 27, 2017, https://www.ncleg.net/Sessions/2017/Bills/House/PDF/H589v6.pdf.
[16] Annual Energy Outlook 2019 with Projections to 2050, US Energy Information Administration, January 24, 2019, accessed at www.eia.gov/aeo.

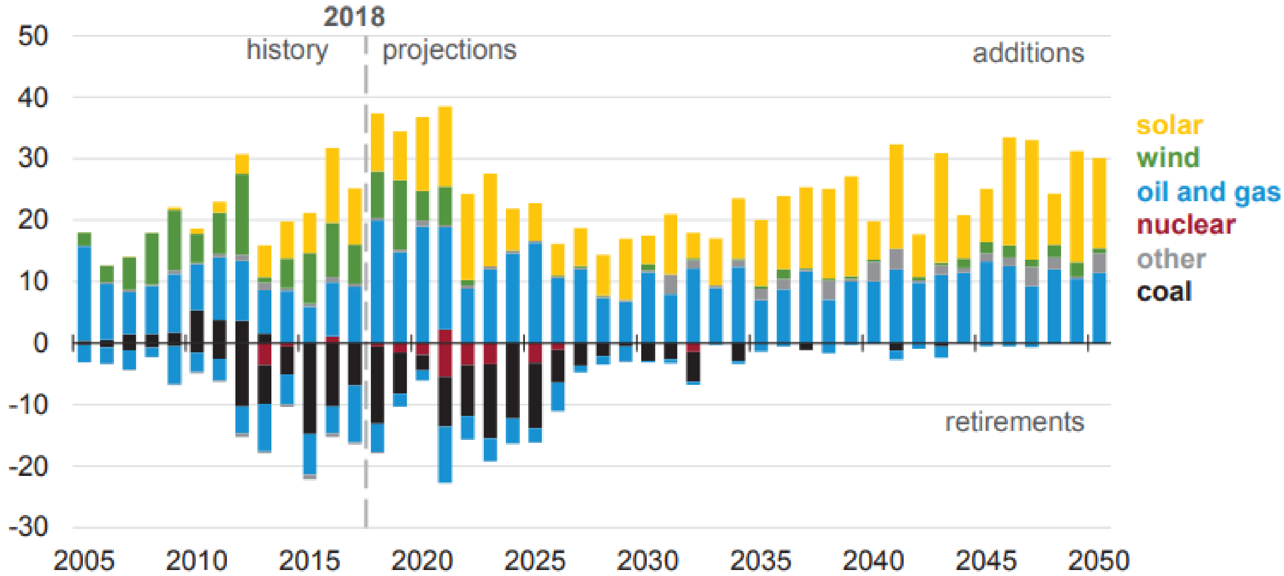

Figure 1: US Annual Capacity Additions and Retirements under AEO 2019 (GW)

Figure 1 indicates that there will be substantial retirement of older, less efficient, coal and natural gas and oil power plants. It also projects substantial growth in natural gas and solar PV power plants over the next 4 years. In addition, wind capacity continues to grow in the short term, primarily due to projects that have already started and are eligible for the federal Production Tax Credit. This tax credit is due to phase out this year but projects that begin construction before December 31, 2019 can claim the credit.[17]

5. Projections Based on Program and Policy Scenarios

5.1 Scenarios Modeled by Each Organization

Each modeling organization chose specific program or policy scenarios and market conditions to model based on their interests. These scenarios included clean technology standards, carbon trading programs, carbon mass cap programs, or some combination of scenarios. Each type of scenario is summarized below.

Accelerated Coal Retirement: This scenario is a simplistic method of evaluating an accelerated decarbonization of North Carolina's electricity fleet by assuming 1) all coal boilers retire by 2030 and 2) the generation shifts to non-emitting sources. This scenario is a response to recent announcements by multiple states and electric utilities that coal plants will be retired early in favor of non-emitting resources.[18] These retirements may or may not be caused by the economics of the power plant.

[17] EIA (2019). "Tax credit phaseout encourages more wind power plants to be added by end of year". US EIA. May 15, 2019. Retrieved on August 8, 2019 from https://www.eia.gov/todayinenergy/detail.php?id=39472

[18] Early coal retirement announcements have been made by Georgia, Indiana, Tennessee Valley Authority, Excel Energy and Southern Company. See Policy and Action Recommendations for more information on the announcements.

Carbon Mass Cap: This scenario is a simple mass cap of 25 MMT of carbon on the electricity fleet with no increased generation from imports. All changes in the electricity fleet are due to market influences rather than imposed requirements.

Regional Trading Program: This scenario assumes North Carolina joins the Regional Greenhouse Gas Initiative (RGGI) program developed by Northeast and Mid-Atlantic states. Each state in RGGI sets its own CO_2 budget. This budget declines each year by 2.5%. The RGGI states combine their budgets into a regional cap with a 3-year compliance period. Fossil fuel power plant must hold CO_2 allowances equal to their emissions over the compliance period and total emissions from all plants may not exceed the regional cap. Allowance auctions are held quarterly, with the money applied to various state programs. Excess allowances that are not needed for compliance by a power plant may either be sold to another plant in RGGI or banked for use in the future. For more information refer to www.rggi.org.

Clean Energy Technology Standard: This scenario requires a certain percentage of retail electricity sales must come from non- or low-emitting resources. The scenario can either be 1) purely clean energy based, a technology-neutral portfolio standard or 2) an expanded version of North Carolina's REPS where more specific targets are given for RE and energy efficiency (EE) programs.[19] Fossil generation is not assumed to be limited under this scenario. Market forces drive what fossil and non-fossil resources the electricity model utilizes to meet both least-cost and policy requirements.

Hybrid: The hybrid scenario is a cap and trade program such as RGGI in a combination with a Clean Energy Technology Standard. This approach works to ensure that 1) a certain portion of fossil generation shifts to clean renewable resources and 2) overall demand decreases due to increases in EE.

Table 4 summarizes specific details regarding the scenario that each organization chose to model. It gives the specific targets that were modeled under each scenario, such as the percentage of total generation that is required to come from RE and EE by 2030. For detailed information on each organization's scenarios, see the attached Appendix: Electric Power Sector Modeling Reports Provided by each Organization.

The scenarios in Table 4 are broken into three groups;

- clean energy driven,
- carbon policy driven,
- and hybrid of both clean energy and carbon policy.

This distinction is important because clean energy driven changes to North Carolina's electricity sector have already lowered CO_2 emissions by 40% since 2005, in the absence of a specific CO_2 policy. These changes were a result of two North Carolina laws; the Clean Smokestacks Act of 2003 (CSA) and the Renewable Energy and Energy Efficiency Portfolio Standard of 2007 (REPS).[20]

The CSA required coal plants to reduce emissions of nitrogen oxides and sulfur dioxides. It resulted in older, more polluting, less economic coal plants retiring and being replaced with cleaner more cost-

[19] Technology can refer to either RE or EE technologies including storage.
[20] See Supporting Document 7 Energy Policy Landscape for detailed information on CSA and REPS.

effective and efficient natural gas combined cycle (NGCC) plants.[21] The REPS required a certain percentage of retail sales be met with generation from renewable energy. The rapid decrease in the cost of solar photovoltaic (PV) panels resulted in this generation being met primarily using solar PV and building a large solar industry in the State.[22] Therefore, the type of approach chosen by North Carolina, clean energy standard, carbon policy or hybrid, is important for creating potential co-benefits to the economy and the public.

[21] See Section Supporting Document 2 Energy Resources for detailed information on the impact of CSA.
[22] See Section Supporting Document 1 Energy Sector Profile and Landscape. Section 2 Deeper Dive: North Carolina's Electric Power Landscape.

Table 4: Scenarios Modeled by Each Organization

Scenario Type	Scenario Category	Georgetown Climate Center (GCC)	Natural Res. Defense Council (NRDC)	Resources for the Future (RFF)	NC State University (NCSU)	NC Division of Air Quality (NCDAQ)
Clean Energy Driven	**Accelerated Coal Retirement**					Retire all coal, EE is 5% of retail sales, Generation shifts to Clean Energy by 2030
	Clean Technology Standard or Expand REPS		EE is 4% and RE is 30% of retail sales by 2030	RE is 23% of retail sales by 2031	EE is 10% and RE is HB589+20% of retail sales, plus 1 GW of storage by 2030	
Policy Driven	**Trading Program**	NC joins RGGI in 2021, 30% CO_2 Reduction by 2030	NC joins RGGI in 2021, 30% CO_2 Reduction by 2030	NC joins RGGI in 2021, 30% CO_2 Reduction by 2031		
	Carbon Mass Cap				25 MMT Mass Cap by 2030	
	Hybrid: Trading Program + Clean Technology Standard		NC joins RGGI in 2021, 30% CO_2 Reduction by 2030 EE is 4% and RE is 30% of retail sales by 2030	NC joins RGGI in 2021, 30% CO_2 Reduction by 2031 RE is 23% of retail sales by 2031		
Model Used		**IPM**	**IPM**	**Haiku**	**TEMOA**	**ERTAC**

5.2 Analysis and Synthesis of Modeling Results

The results of the modeling exercises performed by each organization were provided to DEQ. Not all cases provided by the organizations were included in the analysis. The modeled scenarios that best represented the scenario categories listed in Table 4 were included.

There are several notes regarding the modeling results.

- The electricity models provided results for years 2025, 2030, 2040 and 2050. However, projections beyond 10 years in the future have proved to be unreliable because market forces and technology innovations create unexpected shifts in resources, demand, fuel prices, and policies. Therefore, the DEQ restricted its analysis to 2030.
- Only the IPM model, run by both NRDC and GCC, estimates electricity prices in future years. This estimate is a regional price and may not be representative of what occurs in North Carolina. The DEQ chose to include this limited electricity price information for completeness. Further analysis needs to be conducted on impacts to electricity prices.
- While the models estimated the imported generation, CO_2 emissions associated with imports were not estimated. Emissions from imported generation is an important factor when comparing scenarios. Generation imported from out of state may or may not have equal or lower CO_2 emissions per MWh of generation. To account for CO_2 emissions from imports, the DEQ calculated a 2028 CO_2 emission factor for the SERC Reliability Corporation Virginia- Carolina Region (SRVC) electricity grid system. This emission factor was then applied to imported generation for the year 2030. [23]
- EE is considered "avoided" generation. It is modeled as a decrease in the electricity demand. EE is chosen by the model as "least-cost generation" based on the cost to implement the EE program compared to the cost to generate electricity from other resources.
- Energy storage, more specifically batteries, was only modeled by NCSU. Costs for battery systems are decreasing making them more economic to build and dispatch compared to fossil fuel units. The generation projections under the various modeling scenarios may change after more of the models incorporate batteries as a resource.

5.3 Average Outcomes for the Scenarios

Table 5 presents estimated changes between the economic case and the projections under various program and policy scenarios. For scenarios where there were multiple results, data was averaged. As discussed above, only select scenarios were modeled by each modeling team. The changes are presented for year 2030 only. However, the cumulative impact over multiple years is also an important aspect of any program or policy. The intent of the table is to show how various clean technology driven actions or carbon policy actions could assist in North Carolina's transition to a clean electricity generation fleet.

[23] Estimated CO_2 emissions and fossil fuel generation for the SRVC region for the year 2028 were obtained from an electricity system projection produced by ERTAC. Non-fossil generation was assumed to be dominated by nuclear and added to the fossil generation. This resulted in the 2016 grid emission factor of 805 lb/MWh (estimated by US EPA) being reduced by 13% in 2028.

Accelerated Coal Retirement

The results in Table 5 indicate that accelerating the retirement of all coal units, without the option of increased imports, requires substantial investment in non-emitting resources to replace coal generation.[24] Approximately 20 TWh of generation would need to be replaced with another resource. Based on the results of other models presented in Table 5, DEQ assumes these resources would primarily be energy efficiency, solar PV and possibly a small amount of economic wind. Assuming 5% of this generation would be provided by EE, approximately 8,680 MW of solar or wind capacity must be built. However, this approach leads to significant reductions in CO_2 emissions by 2030, a 52% reduction from 2017 levels (68% reduction from 2005 levels).

Clean Technology Standard

The average results presented in Table 5 for the Clean Technology Standard indicate that it more than doubles generation from RE resources over the economic case. However, since this is limited to an economic incentive for RE, the decrease in fossil fuel generation over the economic case is small, only 12%. Imports also decrease under this scenario, potentially from decreases in electricity prices. CO_2 emissions decrease 36% from 2017 levels which is significantly higher than the 8% reduction under the economic case. Lower electricity prices were projected under this scenario since RE generation has no fuel costs associated with it, which lowers its operating cost compared to fossil fuel resources.

[24] This scenario was modeled by NC DAQ and only included fossil fuels units. Therefore, only the change to coal and gas capacity and generation and the reduction in CO_2 emissions from the retirements could be quantified. Other estimates of the response of the electricity sector to this scenario are based on calculations rather than a model.

Table 5: Average Modeled Changes from an Economic Case to each Scenario in 2030

Scenario Type	Scenario Category	North Carolina's Metrics of Success							
		Decrease Fossil Fuel Generation	Limit Imported Generation	Increase RE and EE Generation	Increase Solar and Wind Capacity*	Lower CO_2 Emissions from Baseline			Limit Rate Impacts
		TWh	TWh	TWh	MW	2030 MMT	Reduction from 2017	Reduction from 2005	Percent
Economic Driven	Accelerate Fossil Retire	-19.96	0.00	19.96	8,680	25.32	52%	68%	NA
	Clean Tech Standard	-8.56	-13.86	15.77	6,907	33.46	36%	58%	-3%
Policy Driven	Join RGGI	-7 to -23	7 to 24	0 to 7	0 to 1,700	34.0 - 41.6	21% - 35%	48% - 57%	2% to 3%
	Carbon Cap	-14.33	NA	17.02	6,700	25.05	52%	68%	NA
Hybrid	RGGI + Clean Tech	-15.40	-5.98	17.02	8,670	29.78	43%	62%	0.1%

Join Trading Program

Notice that the Join Trading Program presents the range of values modeled. This range is important to show since trading programs have different approaches that can have a significant influence on results. One aspect is how allowances are distributed to power plants. Another aspect is the availability and cost of excess allowances. In addition, trading programs permit banking of allowances, creating incentives for early actions to reduce carbon. The range of values indicates that the trading program design impacts its future outcomes.

Joining a trading program, as shown by the models, may not significantly change the electricity system from the economic case. This is due to the basic concept of a trading program, which encourages the economic shift to lower CO_2 emitting sources. This shift is already happening as a result of market forces external to RGGI, low natural gas prices. In addition, joining RGGI was modeled by IPM to slightly increase electricity prices in the region. Therefore, the State would have to carefully analyze the outcomes under different designs of the trading program to ensure its success.

The models indicate that if North Carolina joined RGGI, the decreases in fossil fuel would shift to imports, rather than in-state RE generation. If North Carolina elects to choose such an option, then the trading program may need to be designed to limit imports above a baseline level. Limiting imports was modeled by NRDC using IPM. This scenario results in a 3% shift in generation from fossil to solar PV and increases installed solar capacity by approximately 2,500 MW.

Carbon Cap

This scenario places a cap of 25 MMT on North Carolina and assumes that imports do not increase from baseline levels. Meeting these two requirements results in substantial changes to the electricity system, decreasing fossil fuel generation, increasing RE generation through additional RE capacity, and avoiding generation through EE programs. The changes result in a 52% decrease in emissions from 2017 levels. This modeling scenario only builds 6,700 MW of RE capacity over the economic case. The modeling tool used to project this scenario builds high levels of RE resources under the economic case, resulting in an underestimate of the additional resources compared to scenarios.[25]

Hybrid: Trading Program + Clean Technology Standard

The hybrid combination creates additional incentives to shift fossil fuel generation to RE and EE resources rather than importing generation, which may occur under trading program only approaches. These combined requirements result in a larger decrease in CO_2 emissions.

[25] The economic case for this model builds a large amount of RE capacity, therefore, model does not substantially increase the RE capacity from the application of the carbon cap compared to the capacity changes seen in the other modeling scenarios.

5.4 Individual Model Responses

Figures 3 through 5 visually present the results for each of the scenarios modeled. This data was used to create the summary of the metrics of success given in Table 5. These figures indicate the general response by the electricity sector to a given policy or program scenario.

Increase RE Capacity

Figure 3 shows the change in capacity between the economic case and each scenario for the year 2030. This figure indicates how the "increase RE capacity" metric of success would be achieved by the various scenarios. As indicated in the table, the net change in fossil fuel capacity does not substantially decrease under any of the scenarios, except the "retire coal" scenario, which required the retirements, rather than just decreases in generation. The remaining scenarios retire only a small amount of fossil fuel capacity (or none at all) over the economic coal retirements of 3,000 MW.

However, significant amounts of RE capacity are built under all the scenarios except the "join trading program" scenario. As indicated in Table 5, joining a trading program may result in shifting fossil fuel generation to imports, which may or may not be non-emitting sources.

Decrease Fossil Fuel Generation

Figure 3 indicates how power generation will change due to the targets or requirements of each scenario and which of the scenarios will meet the metrics of success for 1) decreased fossil generation, 2) increased RE generations and 3) limited imports.

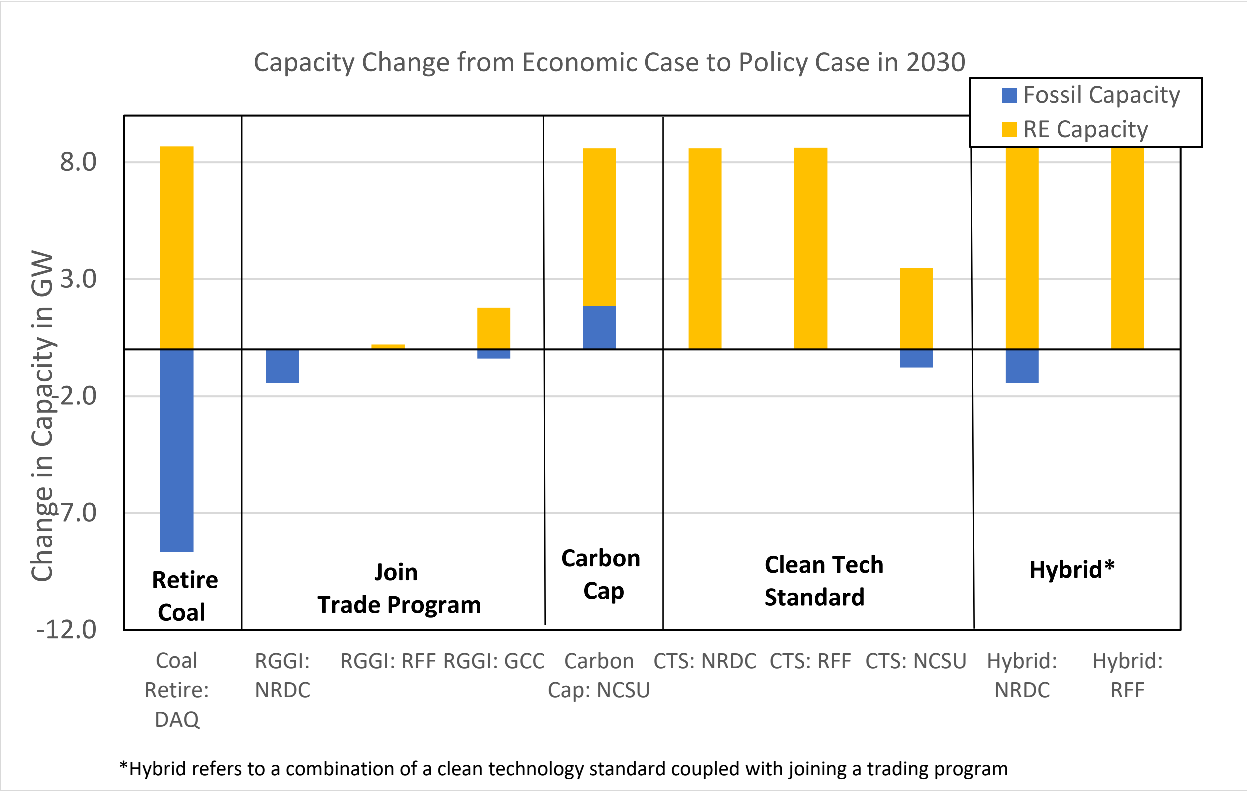

Figure 2: Change in Capacity for Various Modeling Scenarios (MW)

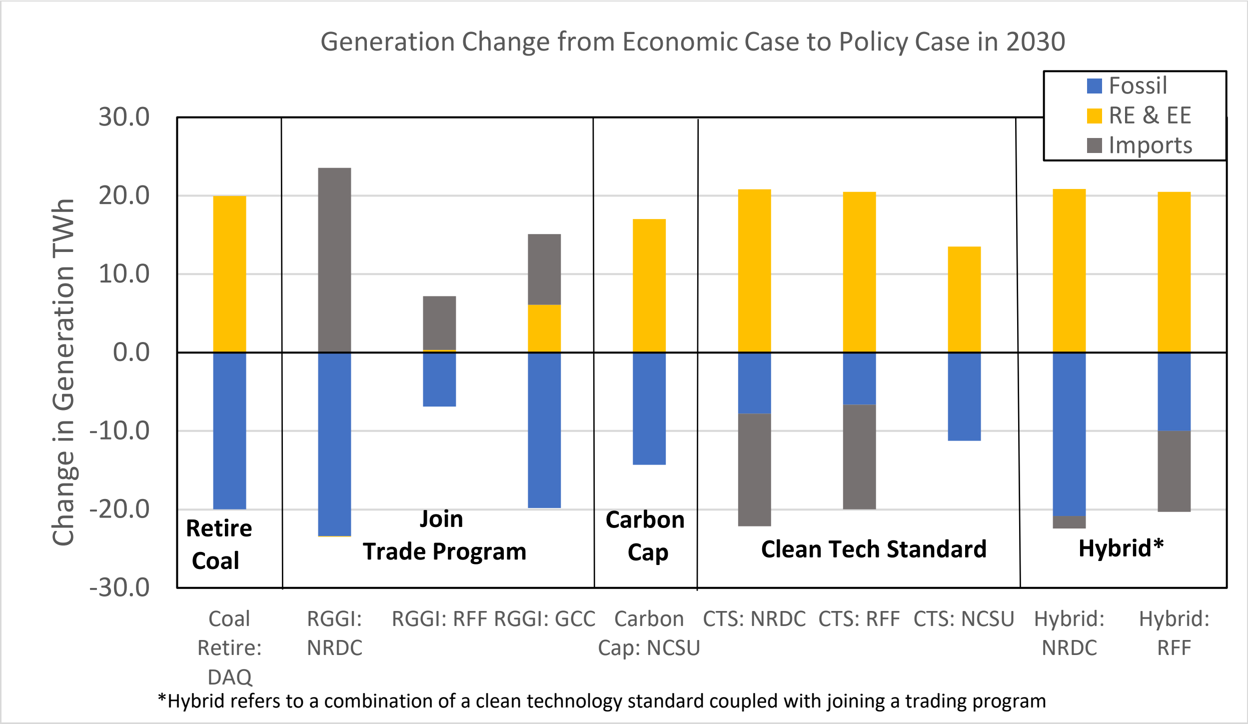

Figure 3: Change in Generation for Various Modeling Scenarios (TWh)

Figure 3 incorporates imports and shows how imports influence generation results under each scenario. It can be seen that all of the scenarios successfully decrease fossil fuel generation, to varying degrees. The largest decrease is from joining a trading program and, as expected, the retire coal approach. However, unless the program is designed correctly, joining a trading program could merely shift fossil generation to imports. The clean technology standard generally produces mixed results, decreasing a lesser amount of fossil fuel generation, increasing imports, while substantially increasing generation from RE resources. The carbon cap and retire coal scenarios also meet the metrics of success based on restricting additional imports as part of their overall design. The direction of the hybrid approach is less clear. However, both hybrid results indicate that fossil fuel generation is reduced, imports are limited, and RE generation increases substantially, which meets the metrics of success for generation.

Note for many scenarios, RE generation is about 20 TWh <u>over</u> the economic case. Given the economic case forecasts about 14 TWh of RE generation, the total is 34 TWh of RE generation in 2030. This is equivalent to approximately 25% of the forecasted generation in 2030.

<u>Reduction in CO2 Emissions</u>

Figure 4 presents the additional CO_2 emissions reductions expected for each scenario over the reductions from the economic case. As discussed previously, this estimate of the reductions includes changes to CO_2 emissions from imports. The economic case alone projects an 8% reduction in CO_2 from 2017 levels, reflecting both decreases in coal generation and imports coupled with increases in NGCC generation.[26]

[26] The figure presents the difference in CO_2 reductions between the economic projection in 2030 and the 2030 projection for each scenario, not the change from 2017 levels.

The largest decrease in CO_2 emissions over the economic case occurs for the retire coal and carbon cap scenarios since these restrict the use of other fossil fuel units to replace generation. Significant CO_2 reductions also occur for the hybrid approach of joining a trading program and a clean technology standard. The clean technology and trading program as separate policies are less successful at lowering CO_2 emissions due to their greater flexibility with shifting between various resources and utilizing imports.

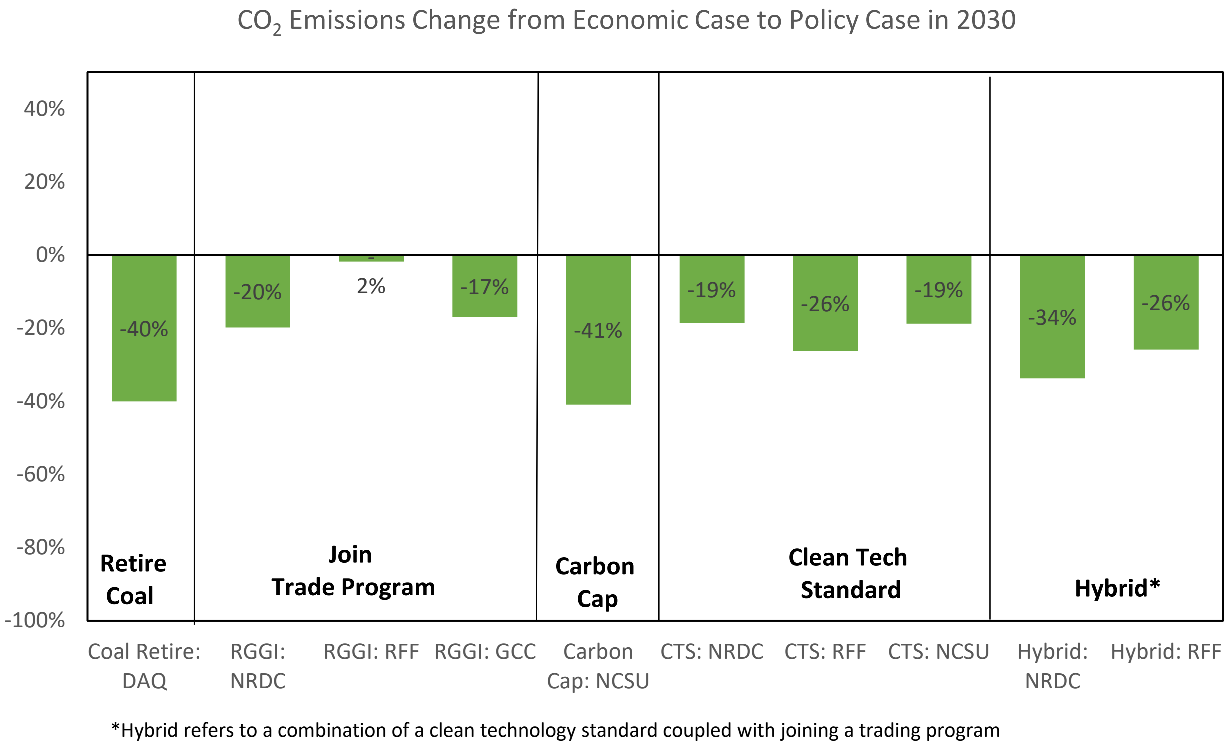

Figure 4: Change in CO2 Emissions for Various Scenarios (percent)

6. Potential Reduction Goals for the Electricity Sector

This section focuses on the impact that reducing fossil fuel combustion at power plants has on North Carolina's overall greenhouse gas (GHG) emissions. Governor Roy Cooper has set a State goal of reducing GHG emissions by 40% from 2005 levels by the year 2030. This goal relates to all emissions of GHGs, not just those from the power sector. However, the power sector currently represents a large portion, 46%, of North Carolina's net GHG emissions. It is also a sector that has the potential to make additional reductions while providing opportunities for economic expansion. Reductions in fossil fuel use would also have significant co-benefits for North Carolinians that are discussed elsewhere in the CEP, including public health benefits.

6.1 North Carolina's Current GHG Emissions Inventory

The GHG emissions presented in this section, both historic and projected for the future, are from North Carolina Greenhouse Gas Inventory (1990-2030) published in January 2019.[27] The inventory estimated the emissions of the six primary pollutants that contribute to atmospheric warming; CO2, methane (CH4), nitrous oxide (N2O), and three classes of organic fluorocarbons. Emissions from electricity generation primarily consist of CO_2 from the combustion of fossil fuels as discussed previously.

Emissions are presented in a unit of measure called "CO_2 equivalent" emissions (CO_2e). Under this standard approach, the emissions of the various pollutants are made equivalent to CO_2 based on their potential to warm the atmosphere.

6.2 Potential Goals and Electricity Sector GHG Emissions

This section presents the impact of each scenario to the current projection of North Carolina's GHG emissions from 2017 to 2030. The average CO_2 emissions reduction forecast for each scenario is overlaid onto the inventory projection. This quickly shows how different types of actions would change the projection.

Emissions are presented in two different figures; 1) the electricity sector and 2) "economy wide" sectors.[28] Note that economy wide emissions are net GHG emissions, which means that total emissions due to the activities that sequester GHGs (sinks) are subtracted from the total emissions due to activities that emit GHGs.

Electricity Sector Goals

Figure 5 presents the GHG emissions from the electricity sector starting in 2005 and going out to 2030. In 2005, North Carolina relied heavily on coal-fired power plant for electricity which resulted in GHG emissions of 79 MMT as CO_2e. Starting in 2010, older coal power plants began to retire and were replaced with lower-emitting NGCC plants. Retirements stopped in 2014 but emissions continued to decrease as the remaining coal plants began operating less due to the low price of natural gas compared to coal. By 2017, emissions from fossil fuel electricity generation had decreased by 34% to 53 MMT due this transition away from coal. Supporting Document 2 Energy Resources, Section 1 Coal and Section 2 Natural Gas of the CEP discusses this transition in detail.

The DEQ's GHG inventory projection data starts in 2017 and indicates emissions continue to decrease, due to the retirement of Asheville and GG Allen coal plants, with a slight increase starting in 2025. This slight increase is no longer projected based on recent fossil fuel cost data. However, no additional coal retirements have been announced, so emissions may remain flat out to 2030.

Figure 5 also includes four lines which estimate the downward trajectory of GHG emissions based on the outcomes modeled for each scenario. These lines give an indication of the potential reductions that may

[27] North Carolina Greenhouse Gas Inventory (1990-2030), North Carolina Department of Environmental Quality, Division of Air Quality, January 2019, accessed at https://deq.nc.gov/energy-climate/climate-change/greenhouse-gas-inventory.

[28] Economy wide emissions refers to emissions from all GHG source and sink activities that are included in the US EPA inventory that also occur in North Carolina.

occur. These reductions, estimated between 2005 to 2030, range from 52% to 68%. Lastly, the figure includes two horizontal lines representing potential reduction goals for the electricity sector.

The figure indicates that joining a trading program may not result in significant emissions reductions beyond what is already expected to occur, a 47% reduction from 2005 levels. Creating a clean technology standard either with a new program or expanding the current REPS potentially results in a 58% reduction from 2005 levels. Coupling the clean technology standard with joining a trading program creates additional GHG reductions. However, the added cost and complexity of joining RGGI is not offset by an equivalent GHG reduction benefit, only an additional 4% decrease. As stated earlier, the carbon cap at 25 MMT and the retire coal case have similar results and are close to the higher 70% reduction goal, with estimated potential reductions of 68%.

Between 2005 and 2017, North Carolina's electricity sector reduced CO_2 emissions 34% and increased electricity generation from solar and wind to 4.5% of total generation. These successes are not based on a specific carbon policy but were driven by clean technology driven forces resulting from the Clean Smokestacks Act of 2003 (CSA), the REPS of 2007, and favorable conditions under the Public Utility Regulatory Policies Act (PURPA) of 1978.[29] These laws created economic incentives to build both a least cost and cleaner electricity system through retiring uneconomic coal plants and increasing the levels of non-emitting RE and EE This modeling synthesis indicates that North Carolina can continue to apply these clean energy based approaches to achieve our goals for cleaner electricity generation.

[29] See Supporting Document 7 Energy Policy Landscape for detailed information on PURPA, CSA, and REPS.

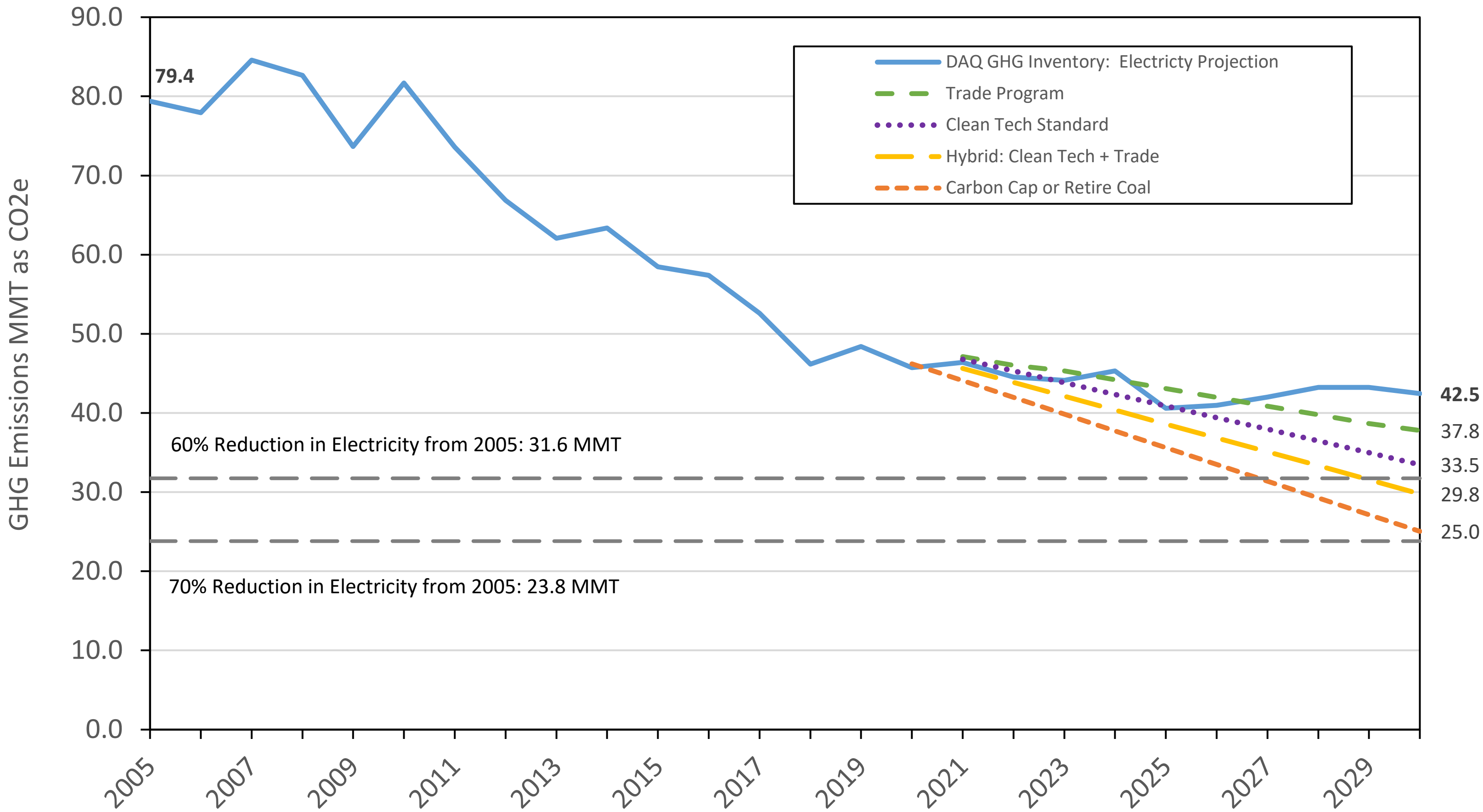

Figure 5: Electricity Sector GHG Emissions: Economic Projection and Modeled Scenarios (MMT as CO2e)

Potential Impacts to Economy Wide GHG Emissions

Figure 6 presents this same information in relation to the economy wide GHG Inventory. This chart indicates that the electricity sector's emissions of 79 MMT as CO2e represented more than half the GHGs emitted in 2005, 152 MMT as CO2e. Therefore, the decrease in the economy wide emissions mirrors that of the electricity sector's reduction between 2005 and 2017.

Figure 6 indicates that joining a trading program may have little impact on economy wide GHG levels in 2030. A clean technology standard and the hybrid of a clean technology standard and joining a trading result in moderate reductions of 36% and 38%, respectively. As expected, the coal retirement and carbon cap scenarios have the largest impact, a 41% reduction between 2005 and projected 2030 levels.

Implementing a 70% reduction goal on the electricity sector for 2030 would result in economy wide GHG emissions decreasing by approximately 42% from 2005 levels.

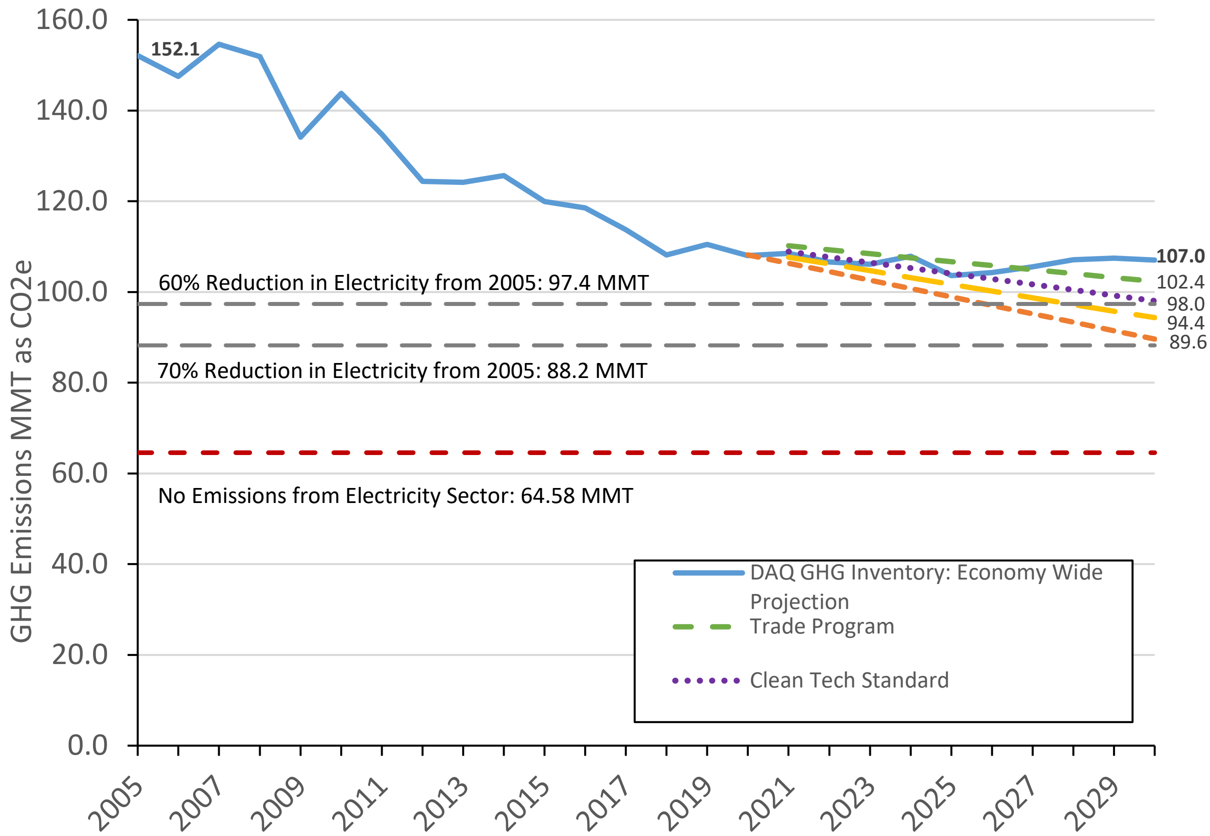

Figure 6: All Sectors Net GHG Emissions: Reference and DEQ Potential Goals (MMT as CO2e)

Appendix

This Appendix contains summaries provided by the following external modeling groups:

- Georgetown Climate Center
- Natural Resource Defense Fund
- NC State University
- NC Sustainable Energy Association
- RFF NC Narrative

GEORGETOWN CLIMATE CENTER
A Leading Resource for State and Federal Policy

SUMMARY OF MODELING ANALYSIS
OF A HYPOTHETICAL POWER SECTOR CAP IN NORTH CAROLINA

Georgetown Climate Center (GCC) engaged ICF International to conduct a modeling analysis to better understand the potential impacts if North Carolina were to implement a power sector cap-and-trade program and link that program to the multi-state Regional Greenhouse Gas Initiative (RGGI). ICF uses the sophisticated IPM model—the same model used by the U.S. EPA, RGGI and Virginia, as well as most utilities in the country—to project the potential impacts of a cap-and-trade program. In conducting its analysis, ICF used the same modeling inputs and assumptions used by RGGI and Virginia to assess the potential impacts of Virginia's current proposal to implement a cap and link to RGGI. As a result, GCC believes the results described below are robust and would be taken seriously by North Carolina stakeholders and the RGGI states.

<u>Business as Usual Highlights</u>

Before analyzing the potential impacts of a policy, ICF projects what will happen in the future without the policy—sometimes called a "business as usual" analysis.

- In the business-as-usual run, NC power sector carbon emissions remained relatively flat from 2018 to 2030, starting at 48 million tons in 2018 and ending at 46 million tons in 2030.

- The model projects that North Carolina will meet and significantly exceed the 2.66 GW solar procurement requirement in HB 589, adding 5.7 GW of new solar capacity by 2030.

- Approximately 1.9 GW of new natural gas combined cycle is projected through 2030 (in addition to the 1.5 GW planned by Duke).

<u>30% Reduction from 2022 to 2032</u>

After the business as usual scenario was run, ICF modeled what is projected to happen if North Carolina implemented a cap-and-trade program beginning in 2022 and reduced emissions 3 percent per year for ten years. This is the same stringency under consideration in Virginia and adopted by the RGGI states.

- The modeling indicates that North Carolina could implement a power sector cap and link to RGGI along a path similar to that proposed by Virginia, with comparable bill impacts depending on the use of allowance value.

- A 30% reduction from 2022 levels would yield the following annual allowance auction revenues based on this analysis:

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Number	46 MT	44.62	43.28	41.98	40.72	39.50	38.32	37.17	36.05
$/ton (2017$)	$3.81	$3.81	$4.08	$4.08	$4.08	$4.38	$4.38	$4.38	$4.59
Total Value	$175.3 Million	$170 Million	$176.6 Million	$171.3 Million	$166.1 Million	$173.0 Million	$167.8 Million	$162.8 Million	$165.5 Million

- In the presence of a cap linked to the RGGI market, North Carolina's power sector reduces its emission more than the cap requires in order to sell reductions into other RGGI states, suggesting that North Carolina can access cheaper reductions than the RGGI states.

- When North Carolina links to RGGI, the RGGI allowance price decreases slightly, consistent with the idea that North Carolina can access cheaper reductions. This should make linking to RGGI easier.

- With a cap in place, North Carolina backs off coal generation significantly (≈40%) and natural gas generation somewhat (≈9%). 800 MW less new gas capacity is added in the state with a cap as compared to business as usual. In the modeling, electricity imports play a role in replacing generation that backs off in the presence of a cap.

- Wholesale power prices increase between $0 and $1.25 per MWhr in North Carolina when North Carolina imposes a cap on the sector. Based on experience in other states, it is likely that retail impacts will be a fraction of the wholesale impact.

- If the allowance revenue is used for customer rebates (as Virginia intends, for example) or investments in energy efficiency (like most RGGI states), bills may actually be reduced.

<u>About the Analysis</u>

- ICF modeled North Carolina's power sector through 2030 with and without a cap on the electricity sector.

    - ICF used the IPM model—the same model used by Duke Energy and most other utilities, U.S. EPA and the RGGI states.

- ICF used the assumptions that Virginia used in its most recent round of modeling. The assumptions were vetted with the RGGI states.

- For North Carolina, ICF assumed:
  - the 2.66GW solar procurement required by HB 589;
  - the natural gas combined cycle additions per the Duke IRP;
  - the coal retirements planned by Duke Energy in its IRP; and
  - EPA/EIA's electricity demand forecast.

- ICF modeled a cap that begins in 2022 at then-current emissions (46 million short tons) and declines 3% per year through 2032. (This cap was chosen to match the RGGI reductions, but on a 2-year lag). The run assumed that North Carolina would link its cap to the 11-state RGGI market.

- The runs were carried out on an expedited basis by ICF and should be considered preliminary.

If you have any questions about this summary or the underlying analysis, please contact Franz Litz at franz@litzstrategies.com or (518) 424-5832, or James Bradbury at james.bradbury@georgetown.edu or (202) 661-6673.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 157

In the Matter of:	**)**	**NCSEA'S INITIAL COMMENTS ON DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC'S INTEGRATED RESOURCE PLANS**
2018 Biennial Integrated Resource Plans and Related 2018 REPS Compliance Plans	**)**	

NCSEA'S INITIAL COMMENTS ON DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC'S INTEGRATED RESOURCE PLANS

Pursuant to the North Carolina Utilities Commission ("Commission") Rule R8-60(k) and the Commission's January 24, 2019 *Order Granting Extension of Time and Closing Discovery Period* and the Commission's February 8, 2019 *Order Granting Second Extension of Time*, the North Carolina Sustainable Energy Association ("NCSEA") submits the following comments on the 2018 integrated resource plans ("IRPs") submitted by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, Inc. ("DEP") (collectively, "Duke").

I. INTRODUCTION

In its closing comments in the *Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans* issued on June 27, 2017 in the 2016 IRP docket, the Commission stated:

> Integrated Resource Planning is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable electric service. Potential significant regulatory changes, particularly at the federal level, and evolving marketplace conditions create additional challenges for already detailed, technical, and data-driven IRP processes. The Commission finds the IRP processes employed by the utilities to be both compliant with State law and

> reasonable for planning purposes in the present docket. The Commission recognizes that the IRP process continues to evolve.

In its 2018 IRPs, Duke failed to identify a generation resource mix that is least cost for both the utility and its ratepayers. As set forth in these Comments and the accompanying report, Duke's IRPs notably ignore a least cost alternative which would allow for the utilization of distributed generation resources including specifically renewable energy. Further, Duke's IRPs are inconsistent with their comments in other proceedings and also to the media.

Recently, Duke has spoken publicly about its plans to incorporate more distributed solar into its generation mix. In a February 28, 2019 news article, Duke employee Ken Jennings stated that Duke plans a new study to show how to significantly boost Duke's system capacity for renewable energy by 2050. Specifically, Mr. Jennings stated that Duke currently estimates that its grid systems will be able to handle about 20% of peak power generation from renewables in 2025 and the new study aims to make the grid capable of supporting as much as 50% of peak demand from renewables by 2050.[1] This study and the accompanying plans to substantially increase renewable generation are not discussed in Duke's IRPs. Instead, Duke forecasts increased centralized generation.

Duke previously introduced the idea of modernizing its grid as a means to incorporate more distributed generation in the 2017 DEC and DEP rate cases and has continued to pitch modernization investments to its investors. Duke has presented and is continuing to seek approval for substantial investment in the grid. Duke's purpose for

[1] John Downey, *Duke Energy Study to Look at Expanding Renewables Capacity on the Grid*, CHARLOTTE BUSINESS JOURNAL, February 28, 2019, *available at* https://www.bizjournals.com/charlotte/news/2019/02/28/duke-energy-study-to-look-at-expanding-renewables.html.

investing in the grid is primarily to prepare the grid for the integration and utilization of an influx of demand-side resources, including new technologies that reduce peak costs and preparing for a future where demand and supply is largely met on the distribution system.

Yet, in these IRPs, that future is nowhere to be found as the grid improvement plans are ignored. The central question remains: why does the future of energy look different when Duke is seeking to spend billions of dollars on the electric grid to incorporate distributed generation than when Duke is seeking approval to spend billions of dollars in traditional, centralized generation? From NCSEA's perspective, Duke wants to make two massive capital expenditures when only one is necessary. Duke's continued spending on centralized generation resources should negate the need to upgrade its grid, ostensibly to accommodate distributed energy resources ("DERs"); conversely, Duke's spending to upgrade the grid to accommodate distributed energy resources should negate the need for continued spending on centralized generation resources. Investing such large amounts of capital in both will undoubtedly leave ratepayers responsible for stranded investments. Until it is clear which future Duke is actually committing to, no new supply-side resources should be approved.

NCSEA also has serious concerns as to whether the resource planning that Duke has presented is the most cost effective. NCSEA's analysis and the accompanying report from Synapse Energy Economics, Inc. ("Synapse") show that Duke's current operation fleet is not efficient and that the operations are dramatically restricting the use of renewables. The analysis also shows that Duke's proposed need to build new capacity resources is strictly a product of its failure to engage neighboring markets.

Finally, NCSEA believes that the future of utility scale solar power purchase agreements ("PPA") need to be addressed by the Commission. For the first time, a significant number of qualified facilities ("QFs") will be reaching the end of their PPAs within the planning horizon. These QFs have remaining life, and the Commission needs to decide how they should be addressed in the IRP process.

N.C. Gen. Stat. § 62-2(3a) states that the policy of the State of North Carolina regarding public utilities includes the following assertion regarding integrated resource planning:

> To assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills[.]

Commission Rule R8-60(a) further states regarding the "Purpose" of the Integrated Resource Planning and Filings Rule: "[t]he purpose of this rule is to implement the provisions of G.S. 62-2(3a) and G.S. 62-110.1 with respect to least cost integrated resource planning by the utilities in North Carolina." Rule 8-60 goes on to give the comprehensive requirements in North Carolina to prepare and submit a sufficient IRP. Duke has failed under the guidelines of the statute and as outlined in that rule to present the least cost integrated resource plan.

II. DUKE'S INTEGRATED RESOURCE PLANS ARE NOT THE MOST COST EFFECTIVE PLANS

Despite claims by Duke that these IRPs plan for future resource needs, "[i]n the most reliable and economic way possible while using increasingly clean forms of energy to meet those needs," these IRPs plan for an overly expensive resource mix that barely expands the use of clean energy beyond those that are legislatively mandated. These IRPs reflect the intentions of a utility that seems to still be planning for the electricity system of the past and not one that is taking steps towards creating the cleaner, cheaper, smarter, more reliable, and more resilient electricity system that North Carolina's future needs require. NCSEA believes that the Duke IRPs do not present a plan that will "[r]esult in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills," therefor do not comply with the requirements of N.C. Gen. Stat. § 62-2(3a) or Rule R8-60(c)(2).

The Duke IRPs foretell an energy future for North Carolina that is inconsistent with current trends shaping the energy industry. With a heavy reliance on natural gas and other traditional generating resources, the plans fail to account for cost-effective clean energy alternatives to the increasingly uneconomic operations of Duke's existing coal plants. For example, Duke's IRPs call for an additional build out of over 9,000 MW of new natural gas plants, but less than 5,000 MW of new renewables (namely solar PV and battery storage), from 2019 to 2033. But especially with the advent of viable battery storage technologies, renewable resources can satisfy a far larger portion of the Duke's energy and capacity needs at a lower economic and environmental cost.

A. SYNAPSE'S REPORT

The report included as **Attachment 1** ("Synapse Report") details a rigorous, scenario-based analysis of alternative energy resource plans for Duke. It details a realistic clean energy future that provides both the energy and capacity to meet the needs of Duke's customers, while effectively meeting future reliability requirements as traditional generating resources are retired. The report was prepared by Synapse Energy Economics, Inc. ("Synapse"), a leading energy, economic, and environmental consulting firm whose clients include state utilities commissions, RTO/ISOs, local governments, and governmental associations including the National Association of Regulatory Utility Commissioners (NARUC).[2] The report was prepared using the EnCompass capacity expansion and production cost model, which is widely used for integrated resource planning and other forecasting and analytical purposes.

Key takeaways from the Synapse Report include:

- The Synapse Report models three distinct scenarios: the proposed Duke Integrated Resource Plan, a Clean Energy Scenario, and an Accelerated Coal Retirement Scenario.
- Duke's projected 2033 resource capacity mix includes 56% (27 GW) fossil fuels, nearly equal to its 2019 resource proportion, and just 23% renewables (11 GW).
- In the Clean Energy Scenario set forth in the attached report, by 2033 gas and coal would compose 32% of Duke's capacity mix, while renewable resources, including solar PV and battery storage, would make up 49% (27.5 GW) (with existing nuclear, hydro, and energy efficiency making up the rest).

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[2] Synapse has specifically provided consulting analysis and reports in numerous Commission Dockets, including: Docket No. E-100, Sub 158 (the 2018 Avoided Cost Docket); Docket No. E-7, Sub 1134 (Application of Duke Energy Carolinas, LLC for Approval to Construct a 402 MW Natural Gas-Fired Combustion Turbine Electric Generating Facility in Lincoln County); Docket No. E-100, Sub 148 (the 2016 Avoided Cost Docket); Docket Nos. E-2, Sub 926 and Docket No. E-2, Sub 931; and Docket Nos. E-7, Sub 831 and Docket No. E-7, Sub 790. Synapse has also provided consulting services and/or analyses regarding other energy-related issues in North Carolina.

- Duke acknowledges that its current IRPs development tools are incapable of modeling the full value of renewable and distributed energy resources, including storage.[3] The Synapse model, by contrast, is capable of more accurately evaluating the costs and benefits of these resources.
- Duke's proposed IRPs add renewables barely above the amounts sufficient for the utility to comply with minimum legislative requirements, whereas the Clean Energy Scenario details how Duke can build more renewables at lower cost than traditional resources.
- Duke's must-run designations force coal plants to operate regardless of optimal cost considerations and require high levels of coal generation in 2033. When must-run designations are removed, economic signals dictate that coal generation drops significantly. Coal generation is markedly lower in 2019 in the Clean Energy Scenario than in the Duke IRP Scenarios.
- Total production costs of a Clean Energy Scenario are far cheaper than under the proposed IRP. With the removal of must-run designations and the build out of cheaper renewable resources, total production costs of a Clean Energy Scenario are over $1.5 billion less than the proposed IRPs in 2033.
- By 2033, Duke's plan emits almost 50 million tons of CO2 annually, while the Clean Energy Scenario emits just under 30 million tons. The removal of must-run coal designations leads to an immediate reduction of nearly 16 million tons of carbon in 2019.

[3] DEC IRP, p. 31, DEP IRP, p. 31.

- Under the Accelerated Coal Retirement Scenario, in which four additional coal units are retired early, EnCompass projects increased energy imports to make up for retiring generation. Production costs and emissions declines for the Accelerated and Clean Energy Scenarios are almost identical.
- The Clean Energy Scenario maintains the required 15 percent reserve margin and EnCompass projects no loss-of-load hours and sees zero hours with unserved energy, proving that the retirement of fossil fuels and build-out of renewables leads to no new system reliability issues.
- The Clean Energy Scenario provides significant health and cost savings to the people of North Carolina due to the increased utilization of existing low-pollutant nuclear and renewable resources to generate in the place of coal. By 2033, North Carolina residents could see up to $354 million in avoided health impacts due to a decrease in hospital room visits and lost work days.
- North Carolina ratepayers can expect to save between .24 cents/kWh and .48 cents/kWh through 2033, leading to a decrease in average annual electricity spending throughout the study period of 4 to 9 percent.
- Corresponding average annual electricity costs for residential customers decrease between $27 and $58 per year.

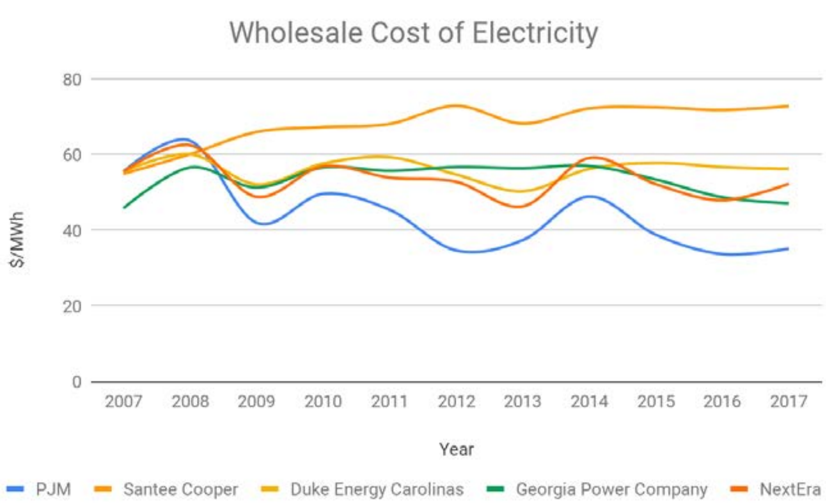
The Synapse Report clearly demonstrates that the Duke IRPs have significant limitations and at the very least fail to adequately consider a full range of scenarios with respect to the economic dispatch of coal units and the deployment of additional renewable and distributed energy resources. As the Synapse Report details, a clean energy future for

North Carolina customers will decrease energy costs, greatly reduce harmful greenhouse gas and other air pollutants, and drive the proliferation of new renewable resources.

B. ADVANTAGES OF WHOLESALE MARKET COMPETITION

Duke is working within an insular system which is bound to be inefficient. While Duke's wholesale cost of power is comparable for other IOU's with the region, its costs are not the most cost-effective in the region. The neighboring PJM marketplace wholesale costs continue to decline where DEC's costs have remained stagnant over the past ten years as shown below in Chart 1.

Chart 1: Recent Wholesale Costs of Electricity by Source[4]



As demonstrated in the Clean Energy Scenario presented in the Synapse Report, allowing system imports to make up a greater share of Duke's generation portfolio takes advantage of these lower out-of-system costs and lower overall operating costs.[5] Furthermore, the Commission has recognized that Dominion participation in PJM has lowered costs for their customers, stating that:

[4] SNL Financial.
[5] See explanation on p. 5 of attached Synapse Report.

> The Commission finds the testimony of Public Staff witness McLawhorn persuasive. He concluded that DNCP's cost-benefit analysis methodology and assumptions were reasonable, and that even if the quantification was overstated, there has been a net economic benefit to DNCP's customers from PJM membership. Witness McLawhorn also stated, based on the most current projections of natural gas prices, capacity prices and other PJM-related costs, the Public Staff expects the net economic benefits of DNCP's membership in PJM to continue . . . The evidence presented in this case demonstrates that DNCP's integration into PJM has benefited its customers, and that those benefits can be expected to continue even if the Commission relieves the Company from compliance with most of the PJM Order conditions.[6]

Before approving their proposed IRPs as "least-cost," the Commission must adequately assess whether Duke's refusal to consider engaging in a competitive wholesale market is actually resulting in lower costs to customers.

III. DUKE'S INTEGRATED RESOURCE PLANS ARE INCONSISTENT WITH DUKE'S OTHER PLANS

A. POWER/FORWARD CAROLINAS A/K/A GRID MODERNIZATION PLAN A/K/A GRID IMPROVEMENT PLAN

Duke has presented limited grid plans in its 15-year IRP forecasts, but for reasons unclear it has failed to directly link its ongoing, massive grid modernization project known as Power/Forward Carolinas ("Power/Forward").[7] Power/Forward was introduced as a concept during the DEP's 2017 general rate case in Docket No. E-2, Sub 1142,[8] and DEC officially requested for approval of cost recovery measures during the DEC's 2017 general rate case in Docket No. E-7, Sub 1146 for its portion of the $13 billion bi-territory grid

[6] *Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions*, p. 144, Docket No. E-22, Sub 532 (December 22, 2016).
[7] As Duke's plans have evolved over the past 18 months, the name has changed as well. Duke's proposal has, at times, been called "Power/Forward Carolinas," "Grid Improvement Plan," and "Grid Modernization." NCSEA uses these terms interchangeably in these comments.
[8] *Direct Testimony of David B. Fountain*, pp. 34-35, Docket No. E-2, Sub 1142 (June 1, 2017).

plan.[9] While the Commission ultimately rejected DEC's proscribed cost recovery rider mechanism, Duke still promotes grid modernization to its shareholders. Specifically, in its *Duke Energy Winter Update 2019*,[10] Duke claims to project an even larger $25 billion grid modernization effort as part of its future utility investment across all its service territories.

Duke's grid improvement/modernization plans are premised upon security, resiliency and, also, the idea that the grid needs to be flexible to allow for the integration and utilization of demand-side technologies, demand response, energy efficiency, and growing renewables. The new resources introduced to the grid to incorporate these guidelines will change load shape and have the potential to eliminate the need to build anymore supply-side resources. NCSEA supports a flexible grid that allows for the utilization of such demand-side technologies.

However, Duke's Power/Forward grid modernization plans do not appear in its IRPs. Despite comprehensive Rule R8-60 requirements regarding forecasting future generation investments, Duke's future scenario painted in its Power/Forward plan is not present when Duke seeks to receive approval for plans to utilize resources and funds for future generation. In fact, it appears that this future scenario only appears when Duke is seeking separate investment on its grid, despite the clear overlap in issues related to generation sources and other issues related to grid improvement. In fact, DEC Witness Robert M. Simpson III ("Witness Simpson") acknowledged the role of integrating distributed generation as an important factor in the Power/Forward plan. In his direct

[9] *Duke Energy Carolinas, LLC's Application to Adjust Retail Rates and Charges, Request for an Accounting Order and to Consolidate Dockets*, p. 4, Docket No. E-7, Sub 1146 (August 25, 2017).
[10] *See generally, Duke Energy Winter Update 2019*, Slide 7, *available at* https://www.duke-energy.com/_/media/pdfs/our-company/investors/winter-2019-ir-update.pdf?la=en (last accessed March 6, 2019).

comments, he stated that the Power/Forward initiative will "primarily focus on projects that . . . [f]urther integrate and optimize intermittent distributed renewable generation[.]"[11] Witness Simpson went further in his Rebuttal Testimony in affirming the Power/Forward plan as a means to prepare the grid for decentralized, distributed generation:

> The primary goals of Power/Forward Carolinas are to significantly reduce the number and duration of outages the system experiences, and to transform the grid by enabling 21st-century performance capabilities Secondary [sic]—but also important—goals include improving the customer experience, by leveraging technology to make payment and usage information more easily accessible, and preparing the grid for the increased adoption of distributed energy resources ("DER").[12]

Witness Simpson further stated that the proposed ten-year scope of Power/Forward was found "to be the most practical time period to execute the intiative (sic) because that time-frame aligned with the Company's forecast of increased adoption of DER such a solar, storage, and microgrids."[13] Finally, Witness Simpson stated that NCSEA Witness Caroline Golin was "incorrect" in characterizing that the Power/Forward plan does not address "renewables."[14] Clearly, when DEC sought to recover costs for the Power/Forward plan, DEC intended for the pitch to be that the Power/Forward grid plan would utilize distributed generation.

Power/Forward also includes a voltage-management program entitled Integrated Volt/Var Control ("IVVC") which will allow the Duke utilities to "manage distribution circuits such that any impacts to customers with large motors sensitive to voltage control can be reduced," and also allow for the utilities to utilize peak shaving and emergency

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[11] *Direct Testimony of Robert M. Simpson III for Duke Energy Carolinas, LLC*, Docket No. E-7, Sub 1146, p. 24.
[12] *Rebuttal Testimony of Robert M. Simpson III for Duke Energy Carolinas, LLC*, Docket No. E-7, Sub 1146 ("Witness Simpson Rebuttal Testimony"), p. 4.
[13] Witness Simpson Rebuttal Testimony, p. 15.
[14] Witness Simpson Rebuttal Testimony, p. 38.

modes of operation.[15] Duke predicted that IVVC will enable 2% voltage reduction for energy conservation, an average roughly 1.4% load reduction in DEP territory and a corresponding and similar sized voltage reduction in DEC territory.

Power/Forward (or any other, later iteration of grid modernization) is not broached in Duke's IRPs, despite the fact that Power/Forward has the purpose, as advertised by Duke, of utilizing demand side resources, reducing peak costs, creating more efficiency within the system and flattening load. NCSEA believes these grid improvement plans, to the extent that they can demonstrably affect Duke's generation portfolio and any other express and implicit factors which are contained within the IRP rule and statute, should be accounted for in Duke's IRPs.

Over the past year, Duke has presented two very different futures to the Commission. The first requires substantial investment in the grid to allow for Duke to pursue the use of demand side management, flexible load, and other benefits associated with distributed generation. The other future, highlighted in these IRPs, outlines substantial investment in centralized generation while making no mention of efforts in the Power/Forward plan to utilize distributed generation and associated technologies. This practice of putting these two concepts in silos is not beneficial for the utilities or, more importantly, the rate payers. The IRP as codified was intended for scrutiny, by the Commission and by intervenors, to allow for the utility to present the best possible energy system for rate payers. NCSEA believes that the holistic approach to this question includes the afore-mentioned grid modernization plans.

[15] *North Carolina Grid Improvement Plan Pre-Read Packet for Stakeholder Workshop*, p. 47; this document was attached as NCSEA Exhibit PB-2 to the Direct Testimony of Paul Brucke, P.E. on behalf of North Carolina Sustainable Energy Association filed in Docket No. E-100, Sub 101.

B. 50% Renewable Energy Penetration Study

As noted above, Duke has recently announced that it has retained the National Renewable Energy Laboratory to study how their grid can accommodate renewable energy penetration of 50% of peak demand.[16] Notably, neither DEC nor DEP's 2018 IRPs come anywhere near this threshold. If Duke genuinely believes that its IRPs represent the future of electricity generation in North Carolina, then such a study should be unnecessary.

The fact that Duke is undertaking such a study undermines the credibility of their own IRPs, and calls into question how Duke has modeled clean energy resources. As discussed above, the Synapse study shows that Duke has unfairly marginalized clean energy resources. Similarly, the Virginia State Corporation Commission rejected Dominion Energy Virginia's integrated resource plan because of its failure to adequately model clean energy resources, and particularly their cost.[17]

IV. Emerging Issues

A. Integrated Distribution Planning

Commission Rule R8-60(g) requires that:

> As part of its integrated resource planning process, each utility shall consider and compare a comprehensive set of potential resource options, including both demand-side and supply-side options, to determine an integrated resource plan that offers the least cost combination (on a long-term basis) of reliable resource options for meeting the anticipated needs of its system.

[16] Downey, *supra* note 1.

[17] *Order In re: Virginia Electric and Power Company's Integrated Resource Plan Filing Pursuant to Va. Code § 56-597 et seq.*, Virginia State Corporation Commission Case No. PUR-2018-00065 (December 7, 2018), *available at* http://www.scc.virginia.gov/docketsearch/DOCS/4d5g01!.PDF.

Rule R8-60(g) goes on to make clear that the analysis to develop this plan should take into account the "sensitivity of its analysis to variations in future estimates of peak load energy requirements, and other significant assumptions, including, but not limited to . . . transmission *and distribution costs*[.]" (emphasis added). Additionally, the rule states that the utility's analysis "should take into account, as applicable, system operations, environmental impacts, and other qualitative factors." *Id*.

Historically, utilities in North Carolina have attempted to fulfill the requirements outlined in this rule by primarily identifying bulk power system needs and identifying the supply-side generation and transmission facilities needed to fill these needs. However, as Duke notes, "Technical advancements and declining cost trends in distributed energy resources such as battery storage, distributed solar generation and demand side management initiatives give rise to a future resource portfolio that is comprised of both centralized resources, as well as, a growing penetration of distributed resources."[18] In addition, the substantial growth of distributed solar in the state has already created many opportunities and challenges to North Carolina utilities and has been a key issue for the Commission to consider in several recent proceedings.[19] As noted by Lawrence Berkeley National Laboratory, the rapid increase in DERs has led to, "new challenges for utilities in planning their infrastructure investments and managing power quality at the level of the distribution system. The challenges are distinctly different from the large-scale generation and transmission challenges in regional planning processes."[20]

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[18] DEC IRP, p. 9; DEP IRP, p. 9.

[19] See generally, Docket No. E-100, Sub 101, E-100, Sub 158, Docket No. E-7, Sub 1146, Docket No. E-2, Sub 1142, Docket Nos. E-2, Sub 1159 & E-7, Sub 1156.

[20] Lisa Schwartz, *Overview of Integrated Distribution Planning Concepts and State Activity*, LAWRENCE BERKELEY NATIONAL LABORATORY (March 13, 2018), https://emp.lbl.gov/publications/overview-integrated-distribution.

NCSEA believes the traditional IRP approach employed by investor-owned utilities in North Carolina has not adequately planned for or addressed the challenges and opportunities with the increasing deployment of DERs. To better ensure that utilities are adequately planning for the opportunities created by DERs and for the electricity grid of the future, NCSEA requests that the Commission open a rulemaking docket for stakeholders to develop a framework and adequate requirements for Integrated Distribution Planning ("IDP").

B. Benefits for Ratepayers and Clean Energy

NCSEA believes that IDP is a critical, and currently missing component of North Carolina's traditional IRP process that truly meets the future electricity needs of North Carolinas at the least cost and fulfills the provisions of N.C. Gen. Stat. § 62-2(3a). In Docket No. E-2, Sub 1142, NCSEA Witness Dr. Caroline Golin defined IDP as:

> Integrated distribution planning is a process that utilities undergo to map out their existing systems through a detailed engineering assessment, at the highest resolution, of the current and forecasted dynamics of the grid under multiple scenarios. The purpose of integrated distribution planning is to identify infrastructure changes that may be needed to achieve grid modernization goals. To properly plan for a grid of the future, and the impact of new technologies, integrated distribution planning must include forecasting and assessment of the role of DERs. Thoughtful integrated distribution planning is transparent and participative and can enable the inclusion of more effective investments as well as increase opportunities for third-party participation.[21]

Similar to the definition provided by Dr. Golin, the Regulatory Assistance Project identified three important tasks for IDP.

1. Recognize the capabilities of DERs so that the potential of low cost DER portfolio solutions are considered.
2. Determine how much investment is needed once one takes into account the DER portfolio effects.

[21] *Direct Testimony of Caroline Golin on Behalf of NCSEA*, pp. 20-23, Docket No. E-2, Sub 1142 (October 20, 2017).

3. Provide transparency to consumers and developers about where on a distribution system there is headroom, also known as hosting capacity, to accommodate more distributed generation, EVs, solar PV capacity, and other DERs, and where on the system there are opportunities to provide complementary DERs.[22]

Accomplishing these tasks requires significant data inputs that are currently unknown, or only available to the utility. As described by Dr. Golin, a thorough IDP process would require "high resolution" data from the utilities to fully consider the appropriate placement of DERs and distribution grid investments in ways that would reduce line losses and avoid the need for some of the expensive traditional generation included in the Duke IRPs. By establishing rules for an IDP process that results in the identification of hosting capacity limits and opportunities could help provide a constructive path forward on some of the more contentious issues related to DERs that have come before the Commission in recent years.

While the Clean Energy Scenario modeled in **Attachment 1** outlines a cleaner and cheaper generation portfolio than Duke's IRPs, it still bound by the relatively "low resolution" energy and capacity data publicly available. In the absence of this data and a clear IDP process for North Carolina, the Clean Energy Scenario modeled utility-scale battery and solar projects and did not specifically evaluate the distribution system needs and DER opportunities in the way that a thorough IDP process would.

In 2017, at least 15 states had proceedings planned or underway related to electric distribution planning.[23] While these states have a significant variation in approaches,

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[22] JIM LAZAR, REGULATORY ASSISTANCE PROJECT, ELECTRICITY REGULATION IN THE US: A GUIDE 112 (2nd ed. 2016), *available at* https://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf.

[23] JULIET HOMER ET AL., U.S. DEPARTMENT OF ENERGY GRID MODERNIZATION LABORATORY CONSORTIUM, STATE ENGAGEMENT IN ELECTRIC DISTRIBUTION SYSTEM PLANNING (December 2017), *available at* https://emp.lbl.gov/sites/default/files/state_engagement_in_dsp_final_rev2.pdf.

safety, reliability, affordability, grid modernization, enabling greater customer control over energy costs and sources, and integrating higher levels of DERs were top objectives for seeking deeper state engagement in distribution system planning. These states are recognizing the opportunities enabled by IDP and the thoughtful preparations that are needed as increasing DER deployment continues to alter the traditional relationship between customers and the electric utility.

While there is a growing body of literature around the opportunities and best practices for IDP, Curt Volkmann with GridLab summarizes some of the primary benefits NCSEA believes IDP would provide to North Carolina utilities, customers, developers, and regulators.

> Utilities and their customers can derive substantial benefits from IDP, including lowering costs to reduce rate pressure in a low load growth environment, creating more cost-effective programs with better returns for customers and shareholders, and enhancing customer relationships as interest in DER continues to grow. Customers and developers will have the opportunity to propose, provide and be compensated for grid services, while experiencing more efficient and predictable interconnection processes. Regulators will benefit from increased transparency and data access for optimal solution identification, more efficient regulatory proceedings, and opportunities for more meaningful engagement with utilities and other stakeholders.[24]

These benefits are clear to NCSEA and many of its members and it now seems some of these benefits are becoming apparent to Duke in what it is currently referring to as Integrated System Operations Planning ("ISOP").

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[24] CURT VOLKMANN, INTEGRATED DISTRIBUTION PLANNING: A PATH FORWARD 8, *available at* https://static1.squarespace.com/static/598e2b896b8f5bf3ae8669ed/t/5b15ae6470a6ad59dcb92048/1528147563737/IDP+Whitepaper_GridLab.pdf.

C. Duke's Integrated System Operations Planning

NCSEA is glad to see that Duke is joining other utilities, consumers, and regulators across the country in, "recognizing that the traditional methods of utility resource planning must be enhanced to keep pace with changes occurring in the industry."[25] In both the DEC and DEP IRPs, Duke is proposing to address these shifting trends through an ISOP effort that is similar to what NCSEA and many others refer to as IDP. Duke's description of ISOP includes two of the three important tasks of IDP outlined by the Regulatory Assistance Project (namely recognizing the capabilities of DERs so they are considered in the portfolio and determine how much investment is needed once one takes into account the DER portfolio effects). However, they do not include any description similar to the critical third task of completing and publishing a hosting capacity analysis.

In addition to lacking this critical hosting capacity piece, the description of ISOP in the Duke IRPs is similar to the description included in their Smart Grid Technology Plans ("SGTPs"), which NCSEA criticized as lacking detail and not including any timeline for implementing this ISOP approach. In response to this criticism, Duke stated that:

> The Companies would show that ISOP, which is a planning process rather than a technology, is discussed in the IRP, is covered in the Grid Improvement Plan, and that it has been, and will continue to be, part of the Companies' ongoing stakeholder workshops. Further, DEC laid out the conceptual goals and timelines for ISOP development as part of the settlement agreement developed with NCSEA and filed in the DEC rate case, in Docket No. E-7, Sub 1146, and has been working on it as a baseline for stakeholder feedback.[26]

[25] DEC IRP, p. 31. DEP IRP, p. 31.
[26] *Duke Energy Carolinas, LLC and Duke Energy Progress, LLC Reply Comments on 2018 Smart Grid Technology Plans*, p. 6, Docket No. E-100, Sub 157 (February 6, 2019).

In Attachment B of that proposed settlement agreement between DEC, NCSEA, Environmental Defense Fund, and the Sierra Club, there is a proposed timeline of commitments by DEC to include hosting capacity analyses with its 2020 IRP and will fully implement ISOP by January 1, 2022.[27] NCSEA appreciates the statement Duke made in its SGTP reply comments that it is still using this timeline of commitments as a baseline for stakeholder feedback, but notes that since that settlement was rejected by the Commission, there is currently no formal mechanism to hold Duke accountable to these commitments.

If Duke is still committed to the timeline for ISOP outlined in the proposed DEC 2018 Rate Case settlement, it is vital that the Commission initiate a directly related IDP Rulemaking Proceeding as soon as possible to assure Duke customers, stakeholders, and regulators that ISOP does not become a vehicle for the utility to justify routine/business as usual investments in the grid as "grid modernization" or in the worst case, justify excess investment. As GridLab noted in a recent South Carolina proceeding on grid modernization:

> GridLab believes that stakeholders are best served by having all grid investments — from reconductoring to smart meters to distribution automation — considered as part of a single IDP process. GridLab has found that such distinctions have proven meaningless in any event, as a capability one utility considers business as usual is considered by another utility as a policy/process/standard improvement, and by yet another utility as grid modernization. IOUs may be interested in preferred compensation for grid modernization, which leads to IOU interest in categorization. GridLab believes preferred compensation leads to excess investment, and recommends instead that preferred compensation be dedicated to exceptional performance on measured outcomes.[28]

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[27] *Pilot Grid Rider Agreement and Stipulation Among Certain Parties,* Attachment B, Docket No. E-7 Sub 1146 (June 1, 2018).

[28] PAUL ALVAREZ, DENNIS STEPHENS, & RIC O'CONNELL, MODERNIZING THE GRID IN THE PUBLIC INTEREST: GETTING A SMARTER GRID AT THE LEAST COST FOR SOUTH CAROLINA CUSTOMERS 15 (January 31, 2019), *available at* https://ors.sc.gov/news/2019-02/gridlabs-releases-grid-modernization-report-south-carolina.

By initiating a rulemaking proceeding, NCSEA ultimately hopes that the Commission establishes a set of rules before Duke implements its ISOP process that ensure IDP by regulated North Carolina utilities is:

- Ongoing – A standardized, repeating IDP process like the IRP process has become.
- Integrated – IDP processes must consider and contribute to transmission plans and integrated resource plans. From DER forecasts to demand response programs, IDP processes must be integrated with other electric system component and capability plans.
- Transparent – Stakeholders should have a strong role in the IDP processes and should help determine the criteria used to evaluate proposed projects.
- Objective – Every proposed project identified should be evaluated and prioritized using the same criteria and weighting as every other proposed project in order to deliver collective goals at the lowest cost.
- Measurable – Stakeholders have the right to objective benefit forecasts and benefit measurement.
- Consequential – Utilities should agree to comply with outcomes of IDP processes and deliver the results promised from selected grid projects with utility incentives and consequences based on utility adherence to IDP priorities and outcomes.[29]

Establishing rules to enshrine these principles for IDP can "help address capital bias and associated business process, operating practice, and technology changes and choices of dubious value."[30]

[29] *Id.*
[30] *Id.*

NCSEA believes these choices of dubious value are clear in the expensive overbuild and overuse of fossil fuel resources proposed in the Duke IRP. While we are encouraged by indications that Duke is also starting to acknowledge limitations to its current IRP process, we are not satisfied by the current lack of transparency and unenforceable timeline of commitments that they have currently proposed. Coupling the immediate opportunities for beneficial changes to Duke's planned generation portfolio that are identified in the Synapse Report with a robust IDP process and corresponding rules will help North Carolina take a big step towards a cleaner, cheaper, more resilient, and more reliable electricity system.

D. EXECUTIVE ORDER 80

On October 29, 2018, Governor Roy Cooper issued Executive Order No. 80 ("EO80") committing the State of North Carolina to support the 2015 Paris Agreement goals and honor the state's commitments to the United States Climate Alliance.[31] Broadly, EO80 sets an ambition goal for North Carolina to reduce its statewide greenhouse gas ("GHG") emissions to 40% below 2005 levels. In addition, EO80 sets additional goals including an increase in the number of registered zero-emission vehicles in the state to at least 80,000, reducing energy consumption in state-owned buildings, and directs the North Carolina Department of Environmental Quality ("DEQ") to develop a North Carolina Clean Energy Plan by October 1, 2019.

[31] Exec. Order No. 80 (2018), *available at* https://files.nc.gov/governor/documents/files/EO80-%20NC%27s%20Commitment%20to%20Address%20Climate%20Change%20%26%20Transition%20to%20a%20Clean%20Energy%20Economy.pdf.

In January 2019, DEQ published *North Carolina Greenhouse Gas Inventory (1990-2030)*.[32] The inventory presents an accounting of the state's GHGs emissions by source category from 1990 to 2017 and projects future emissions from 2018 to 2030. This inventory and projections of reasonably expected trends is an essential tool for tracking the state's progress towards achieving the goal of reducing statewide GHG emissions to 40% below 2005 levels. Based on the current projections included in the Inventory, North Carolina will reduce its net GHG emissions 31% by 2025 and will not achieve the 40% reduction goal without additional action.

As stated earlier, the generation portfolio presented in the Synapse Report's Clean Energy Scenario presents substantial additional reductions in GHG emissions compared to the Duke IRPs. In the analysis presented in the tables below, an NC allocation factor (to screen out emissions from SC customers) was applied to the emissions that were avoided in our Clean Energy Scenario compared to the Duke IRPs Scenario. These reductions in North Carolina GHG emissions were then incorporated into the projections in DEQ's GHG Inventory. This analysis shows that the Clean Energy Scenario produces enough of a reduction in overall GHG projections that North Carolina would reduce its net GHG emissions by 40.1% from 2005 levels by 2025 without doing anything altering any of the other GHG emissions projections included in the DEQ GHG Inventory.

[32] NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY, NORTH CAROLINA GREENHOUSE GAS INVENTORY (1990-2030) (January 2019), *available at* https://files.nc.gov/ncdeq/climate-change/ghg-inventory/GHG-Inventory-Report-FINAL.pdf.

Table 1: Status Quo GHG Emissions (MMT CO_2) from DEQ GHG Inventory[33]

Emissions Source	2005	2015	2020	2025	2030
Total Electricity Use	79.37	58.48	45.74	40.59	42.46
Gross Emissions from all Sectors	184.7	154.8	143.6	138.3	141.4
Net Carbon Sinks	-32.7	-34.2	-34	-34	-34
Net Emissions	152.1	120.7	109.5	104.3	107.3
Reduction in Net Emissions from 2005	-	20.7%	28.0%	31.5%	29.4%

Table 2: GHG Emissions (MMT CO_2) Projections Using Clean Energy Scenario Emissions from Synapse Report[34]

Emissions Source (Million Metric Tons)	2005	2015	2020	2025	2030
Total Electricity Use	79.37	58.48	33.8	27.5	28.8
Gross Emissions from all Sectors	184.7	154.8	131.6	125.2	127.7
Net Carbon Sinks	-32.7	-34.2	-34.0	-34.0	-34.0
Net Emissions	152.1	120.7	97.6	91.1	93.7
Reduction in Net Emissions from 2005	-	20.7%	35.8%	**40.1%**	38.4%

While the Duke IRPs present a pathway to a generation portfolio that likely reduces GHG emissions produced by the DEC and DEP systems by more than 40% compared to 2005 levels, they will not allow North Carolina to reach the statewide 40% reduction goal included in EO80. If Duke instead pursued the future generation portfolio presented in the Clean Energy Scenario of the Synapse Report, North Carolina would achieve this goal of reducing net GHG emissions by at least 40% compared to 2005. If the other sectors presented in DEQ's GHG inventory also pursue realistic opportunities for further GHG

33 Analysis adapted from NORTH CAROLINA GREENHOUSE GAS INVENTORY (1990-2030), Table 1-1, *supra* note 29.

34 Note: GHG emissions from the Synapse Report were converted to million metric tons of CO_2 in order to incorporate into the DEQ GHG Inventory projections

emissions reductions than are currently projected, North Carolina would likely exceed the GHG emissions goal in EO80.

E. Renewals of Power Purchase Agreements With Qualifying Facilities

Currently, DEC has 645 MW of capacity provided by qualifying facilities ("QFs") in its generation stack and DEP has 2,163 MW.[35] QFs provide this capacity to DEC and DEP pursuant to power purchase agreements ("PPAs") that typically have terms of 10 or 15 years. Despite the fact the PPAs with QFs will eventually expire, Duke assumes that the PPAs will "be either renewed or replaced in kind."[36] However, there is no guarantee, or requirement, that a QF will continue to provide the utility with capacity past the end of its initial PPA, even if the QF has remaining operational life.

Duke assumes for planning purposes that a QF's PPA will be renewed despite the fact that it has made numerous efforts in other proceedings to make it more difficult for a QF to renew a PPA. In Docket No. E-100, Sub 101, Duke has proposed changes to the Material Modification portion of the North Carolina Interconnection Standard that would make it more difficult for QFs to upgrade equipment when it reaches the end of its lifespan.[37] In Docket No. E-100, Sub 158, Duke has proposed that it have the unilateral authority to terminate a PPA if a QF upgrades equipment.[38] Also in Docket No. E-100, Sub 158, Duke has proposed that QFs that renew their PPA would not receive full payment for the capacity that they provide.[39]

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[35] *Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Joint Initial Statement and Exhibits*, p. 8, Docket No. E-100, Sub 158 (November 1, 2018).
[36] *See*, Duke Energy Carolinas, LLC's Response to Public Staff Data Request No. 6-4 and Duke Energy Progress, LLC's Response to Public Staff Data Request No. 4-12, included as **Attachment 2.**
[37] *Direct Testimony and Exhibit of Paul Brucke, P.E.*, pp. 14-16, Docket No. E-100, Sub 101 (November 19, 2018).
[38] *NCSEA's Initial Comments*, pp. 51-52, Docket No. E-100, Sub 158 (February 12, 2019).
[39] *NCSEA's Initial Comments*, pp. 10-11, Docket No. E-100, Sub 158 (February 12, 2019).

Other wholesale PPAs are removed from DEC and DEP's respective generation stacks when they expire and create capacity needs. However, Duke treats PPAs with QFs differently in its planning process. Accordingly, the Commission needs to decide how DEC and DEP's IRPs should treat QFs at the end of their initial PPAs. Duke's planning process, coupled with their proposal in Docket No. E-100, Sub 158 to restrict capacity payments to QFs that renew their PPAs, is wholly unfair to QFs. A QF with an expiring PPA is assumed in the IRP to remain in the generation stack, which means the IRP does not show a capacity need, which means that a QF would not receive a full capacity payment when it renews its PPA, despite being relied upon for capacity. The paradigm for renewing PPAs with QFs proposed by Duke is nonsensical, and needs to be resolved by the Commission.

V. CONCLUSION

The business as usual IRP process that Duke continues to employ in this proceeding is no longer working as intended for its North Carolina customers. Duke's current IRP process is producing a plan for a portfolio that is less clean and more expensive than other realistic portfolios like the Clean Energy and Accelerated Coal Retirement Scenarios in the Synapse Report. Implementing the portfolios outlined in the Synapse Report would not require drastic reforms to Duke's IRP process or business model.

Further, while we are encouraged by the statements Duke has made about its ISOP process, NCSEA believes that the Commission should initiate a rulemaking proceeding to implement rules so the ISOP process adheres to the principles for IDP identified in these comments. IDP will allow the utilities to identify new DER opportunities that have not yet been identified by Duke, Synapse, or any other party to this proceeding. Appropriate rules will guarantee that IDP maintains sufficient oversight and transparency so as to allow ratepayers, and their representatives, real opportunities to see whether the decisions being made with regard to distributed generation are in their best interests. NCSEA believes that establishing an IDP process for regulated North Carolina utilities will help address shortcomings of the traditional IRP process that is currently in practice.

For all the reasons set forth herein, NCSEA respectfully requests that the Commission reject the Duke IRPs and order Duke to refile new IRPs incorporating the recommendations made in the Synapse Report including, specifically, the least cost model incorporating additional renewable generation. Further, NCSEA requests that the Commission initiate a rulemaking proceeding to establish appropriate rules for integrated distribution planning and address the concerns contained within regarding the expiration of solar PPAs.

Respectfully submitted, this the 7th day of March, 2019.

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CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing document by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

Respectfully submitted, this the 7th day of March, 2019.

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Attachment 1

North Carolina's Clean Energy Future

An Alternative to Duke's Integrated Resource Plan

Prepared for the North Carolina Sustainable Energy Association

March 7, 2019

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FIGURES

1. INTRODUCTION

The Integrated Resource Plans (IRP) filed in North Carolina by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) in September 2018 reflect business as usual for the two utilities. The plans, which run through 2033 and include the Duke service territory in both North and South Carolina, rely heavily on new natural gas capacity. Together, they add more than 9,000 megawatts (MW) of new combined cycle and combustion turbine capacity over the 15-year analysis period from 2019 to 2033 to both meet anticipated increases in electricity demand and to replace certain retiring coal units. Renewable additions are comprised of solar photovoltaic (PV) and battery storage resources but are added in minimum amounts sufficient to comply with North Carolina House Bill 589.

Synapse performed a rigorous, scenario-based analysis to evaluate an alternative clean energy future compared to the more traditional portfolio of fossil-fueled resource additions included in Duke Energy Carolinas and Duke Energy Progress's (collectively Duke Energy) IRPs. The clean energy future analysis included resources such as solar, wind, energy efficiency, and battery storage. These resources were offered to the EnCompass electric sector model to provide both energy and capacity, and to meet future reliability requirements as coal resources in the Carolinas approach retirement. This report compares one such optimized Clean Energy scenario to a Duke IRP scenario. Synapse analyzed the benefits of this modeled clean energy future on the electric power system, emissions, public health, job creation, and electricity customer rates and bills.

Renewable resource options, in addition to those modeled by Duke Energy, are comparably cost-effective to new natural gas for North Carolina ratepayers and offer other benefits to the state.

In the Clean Energy scenario, the EnCompass model is allowed to select the most cost-effective future resource build. In contrast to the Duke IRP scenario, the model chooses to build out solar and storage resources to meet future capacity and energy needs with zero incremental natural gas-fired unit additions. Coal generation declines between the Duke IRP and Clean Energy scenarios, lowering the electric system production cost and reducing emissions of carbon dioxide (CO_2) while maintaining system reliability. Emissions reductions of additional air pollutants result in health benefits to North and South Carolina, avoiding hospital and emergency visits and lost work days. Total revenue requirements of the Clean Energy scenario are lower than in the Duke IRP scenario, and North Carolina consumers see lower electricity rates as a result. Under the Clean Energy scenario, North Carolina consumers also use less energy due to the increased energy savings associated with the High Energy Efficiency scenario from the Duke Energy IRPs. When coupled with the decrease in rates, residential consumers in the state see their average annual electricity expenditures decline by approximately 2.5 to 5.5 percent.

2. SCENARIO ANALYSIS

Synapse used the EnCompass capacity expansion and production cost model, licensed by Anchor Power Solutions, to examine two different future energy scenarios in the Duke Energy service territories from 2018 to 2033:

Duke IRP: The Duke IRP scenario reflects the anticipated energy resource future as outlined in the most recent Duke Energy IRPs. Specifically, the Duke IRP scenario assumes:

- The slate of planned resource additions already contracted or under construction, and the "optimized" natural gas combined cycle and combustion turbine plants selected during the IRP process. Duke Energy Carolinas and Duke Energy Progress were modeled as operating in a single Duke Energy service territory, but this does not assume the "capacity sharing" modeled by Duke in its IRPs as part of its Joint Planning scenario. Rather, the resource additions assumed by each utility in its individual IRPs are included and modeled as part of this scenario.
- Cost and operational data as outlined in Duke's discovery responses to North Carolina Utilities Commission Staff and other intervenors. In the absence of available data, Synapse relied on the Horizons Energy National Database (the primary data source for the EnCompass model) or other industry-recognized sources.
- Retirement dates for certain existing coal generators that are consistent with the utility IRPs.
- Must-run designations for coal units in the service territory, which force coal units to run regardless of price and reflect historical regional generation patterns.

Clean Energy: The Clean Energy scenario reflects an optimized view of the Duke Energy service territory with relaxed assumptions around operation and up-to-date renewable costs:

- The utility reserve margin is set at 15 percent (versus 17 percent in the Duke IRP scenario). This lower reserve margin was selected to be consistent with North American Electric Reliability Corporation (NERC) standards. It also reflects the assumption that as older units with higher forced outage rates retire and are replaced with new capacity, the reliability of the system is improved.
- Must-run designations for coal units are removed.
- Projected load includes the increased electric demand associated with the recent electric vehicle goal established in North Carolina Governor Roy Cooper's Executive Order Number 80.
- Energy efficiency is provided as a supply-side resource based on the High Energy Efficiency scenario in Duke Energy's IRPs.

- Renewable costs are based on the *2018 NREL Annual Technology Baseline*[1] or Lazard's *Levelized Cost of Storage Analysis.*[2]
- The Clean Energy scenario incorporates all planned resource additions outlined in the Duke IRPs that are currently under construction or necessary to comply with North Carolina's renewable procurement regulations but excludes the "optimized" natural gas combined cycle and combustion turbine units that were selected by the System Optimizer model to meet reserve margin constraints in and after 2025.
- The model can choose to build generic utility-scale solar, storage, wind, and paired solar-plus-storage resources in any amount (e.g. no restrictions were placed on either total or incremental renewable capacity), in addition to traditional natural gas-fired generating resources.

More information on the modeling structure, including detail on topology, load, fuel prices, and other assumptions, can be found in Technical Appendix A.

[1] National Renewable Energy Laboratory (NREL). 2018. *2018 Annual Technology Baseline*. Golden, CO: National Renewable Energy Laboratory. Available at: https://atb.nrel.gov/.

[2] Lazard. 2018. *Lazard's Levelized Cost of Storage Analysis: Version 4.0*. Available at: https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2018/.

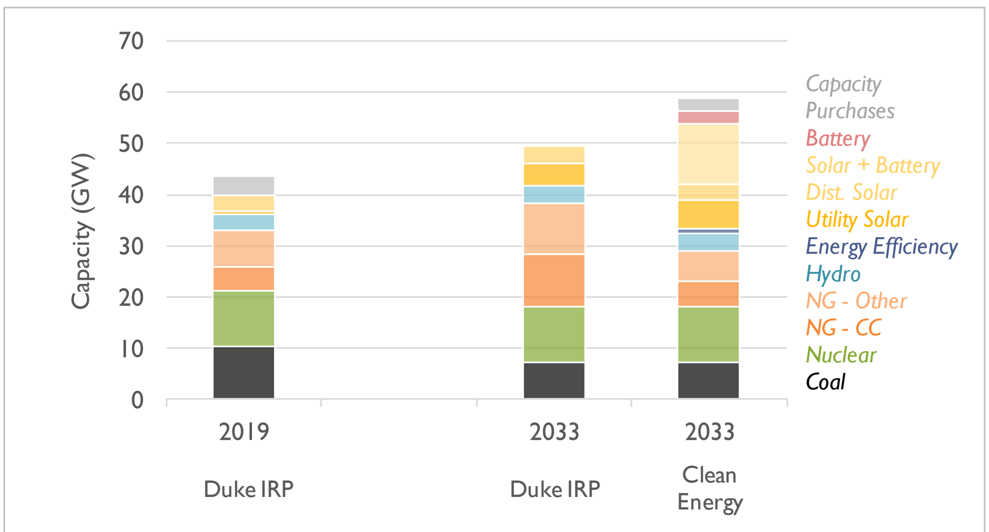
3. RESULTS

3.1. Electric Sector Modeling

New generating capacity is constructed during the analysis period to meet the respective reserve margins in both the Duke IRP and Clean Energy scenarios; however, the type of capacity constructed differs between scenarios. The Duke IRP scenario relies heavily on generic natural gas-fired combined cycle and combustion turbine units, with renewable resources (solar PV and battery storage) added only in amounts sufficient for Duke Energy to comply with North Carolina House Bill 589. The Clean Energy scenario, on the other hand, relies on a slate of clean energy resources to meet its reserve margin requirement that includes energy efficiency, utility-scale storage and solar, 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.

Figure 1, below, shows the generating capacity in the Duke IRP and Clean Energy scenarios in 2033, as compared to Duke's actual capacity mix in 2019. As shown in Figure 1, approximately 55 percent (22 GW) of Duke's installed capacity in 2019 is fossil fuel-powered thermal (coal- or natural gas-fired), 27 percent (10.7 GW) of capacity is nuclear, and the remaining 18 percent (7 GW) comes from hydroelectric, renewable, and distributed energy resources. By 2033, the proportion of fossil-fired resources in the Duke IRP scenario is unchanged at 56 percent (27 GW), while clean energy resources have increased modestly to 23 percent (11 GW).

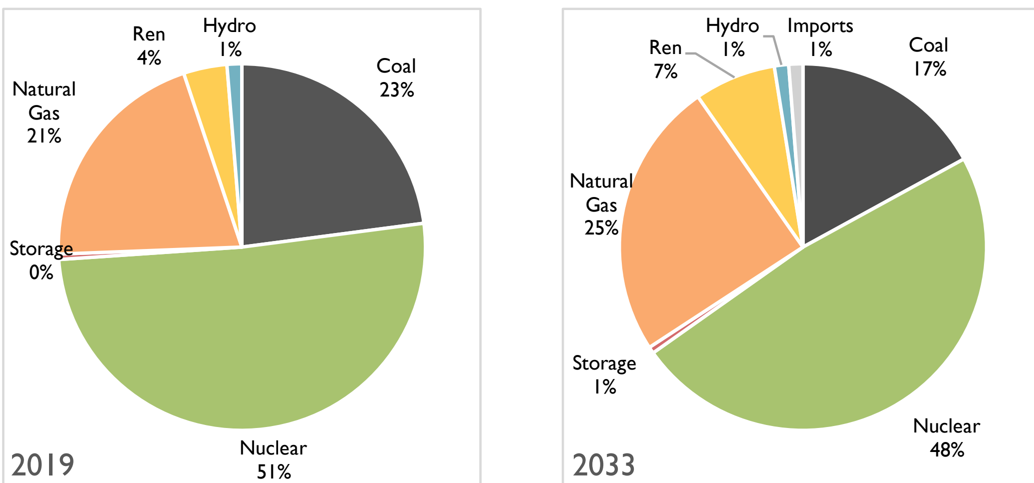
Figure 1. Duke Energy modeled nameplate capacity by scenario, 2019 and 2033



In contrast, gas and coal resources in the Clean Energy scenario drop to 32 percent (18 GW) of the capacity mix by 2033, and renewable energy resources comprise 49 percent (27 GW) of the utility mix. Nuclear capacity remains constant in both scenarios throughout the period. Notably, the EnCompass model makes the choice to retire the Allen coal plant at the end of 2019, accelerating the retirement from Duke Energy's anticipated dates of 2024 (for Units 1–3) and 2028 (for Units 4–5). While the coal capacity is the same at the end of the analysis period for both the Duke IRP and the Clean Energy scenarios, the latter retires a portion of this coal capacity earlier in the analysis period and thus has a lower volume of coal capacity during that time.

As shown in Figure 2 below, the fuel mix in Duke's service territory changes very little over time in the IRP scenario. Coal generation drops from 21 percent in 2019[3] to 17 percent in 2033, while natural gas generation increases over the study period from 19 percent to 25 percent. Renewable generation increases only slightly over the study period, from 4 percent in 2019 to 7 percent in 2033. Note that these percentages do not match those shown in Duke Energy's IRPs in Figure 12-F on pages 69 (Duke Energy Carolinas) and 71 (Duke Energy Progress). This is due to the different assumptions used by Duke Energy and Synapse around operational parameters of individual units and the regional market price of energy.

Figure 2. Modeled generation in the Duke IRP scenario, 2019 and 2033



In the Clean Energy Scenario, shown in Figure 3, renewable generation makes up 21 percent of the fuel mix in 2033 as compared to 7 percent in the Duke IRP scenario. Natural gas generation falls to 9 percent of total generation in 2033, as compared to 25 percent in the Duke IRP scenario in that same year. Imports make up a greater percentage of the generation in the Clean Energy scenario as the model takes advantage of lower out-of-system energy costs. Notably, coal generation is markedly lower in the Clean Energy scenario than in the Duke IRP scenario in 2019, and this immediate decrease can be attributed to the removal of the "must-run designations," which are present in the Duke IRP scenario and force units to run without consideration of their variable costs.[4] Duke's coal-fired power plants are some of the

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[3] Note that approximately one-third of the coal generation shown in 2019 is exported to neighboring utility service territories rather than being used to meet Duke Energy's own load requirements.

[4] Must-run designations are set by Horizons Energy, the developers of the National Database used by the EnCompass model. They are based on Horizons' observations from EPA's Continuous Emissions Monitoring (CEMS) data as well as data from Energy Information Administration (EIA) Form 923. In setting the must-run designations, Horizons assumes that coal generators will retire a coal asset rather than running it under high stress (e.g. daily shut-down) situations for any period of time.

more expensive resources to operate in both scenarios. With the must-run designations applied, the Duke IRP scenario alternates between importing and exporting energy as it seeks to find a use for the costly must-run coal generation that has been forced into the electric grid. In contrast, coal generation falls at the beginning of the analysis period in the Clean Energy scenario when the must-run designations are removed.

Figure 3. Modeled generation in the Clean Energy scenario, 2019 and 2033

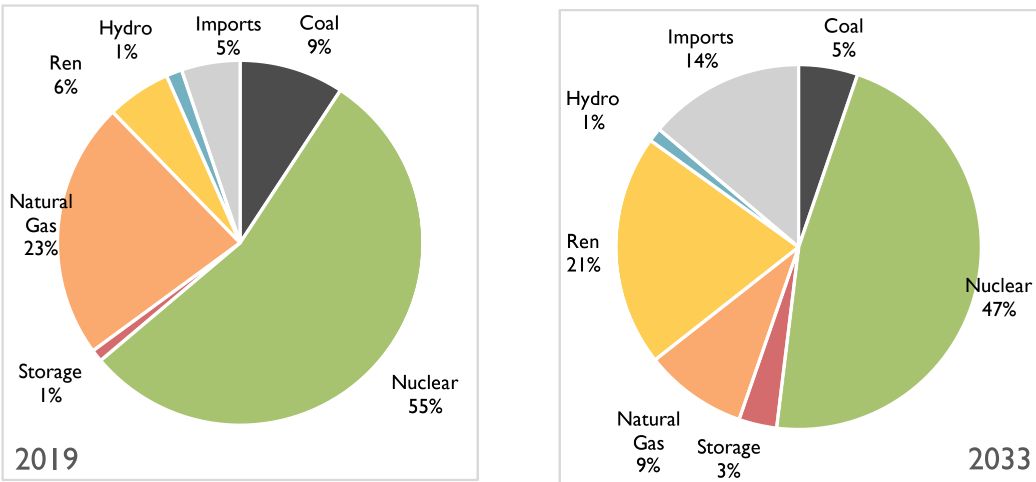
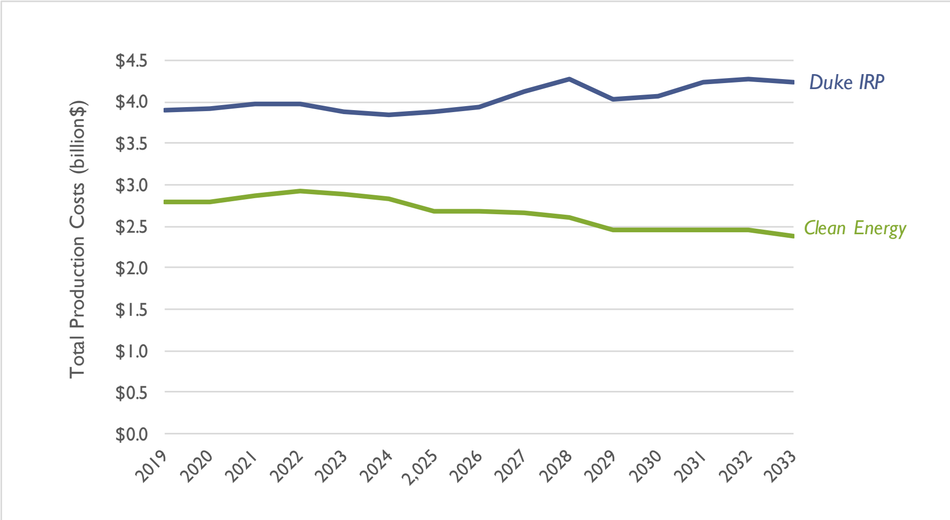


Figure 4 shows the total production cost associated with each scenario over the course of the analysis period. The Clean Energy scenario is considerably less expensive from an operational perspective than the Duke IRP scenario for two primary reasons. First, we note an immediate cost decline in the first year of the analysis period due to the removal of the must-run designations, as described above. Production costs immediately drop by 28 percent when uneconomic coal capacity is no longer forced to generate. In the absence of this coal-fired energy, EnCompass substitutes no- and low- variable cost energy from other sources.

Figure 4. Duke Energy total production cost by year by scenario



From a reliability perspective, Duke Energy meets its hourly demand requirements in all modeled days and hours during the analysis period. The Clean Energy Scenario maintains the required 15 percent reserve margin and EnCompass projects no loss-of-load hours and sees zero hours with unserved energy, even with the increased electric demand associated with the addition of new electric vehicles under Executive Order Number 80.

Figure 5 and Figure 6, below, show energy generation on January 3, 2028—a representative winter peak day—for the Duke IRP and Clean Energy scenarios. Both scenarios rely on nuclear generation and some level of energy imports to meet demand in peak hours and then export energy during the midday trough. The Duke Energy scenario dispatches must-run coal units throughout the day, and uses a mix of natural gas-fired, hydroelectric, and some solar generation to meet the hourly peaks. The modest amounts of battery storage capacity are charged in the early morning and midday hours. Conversely, the Clean Energy Scenario uses very little coal, less natural gas-fired generation, and relies on a greater mix of resources. Battery capacity is charged via solar generation during both an extended morning period and the midday trough, which allows batteries to discharge during evening hours to help meet the evening peak. 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, whether by solar resources within Duke's service territory or via imported energy. The area between the solid line and the dotted line represents energy exports.

Figure 5. Sample winter peak generation by fuel type, January 3, 2028, Duke IRP scenario

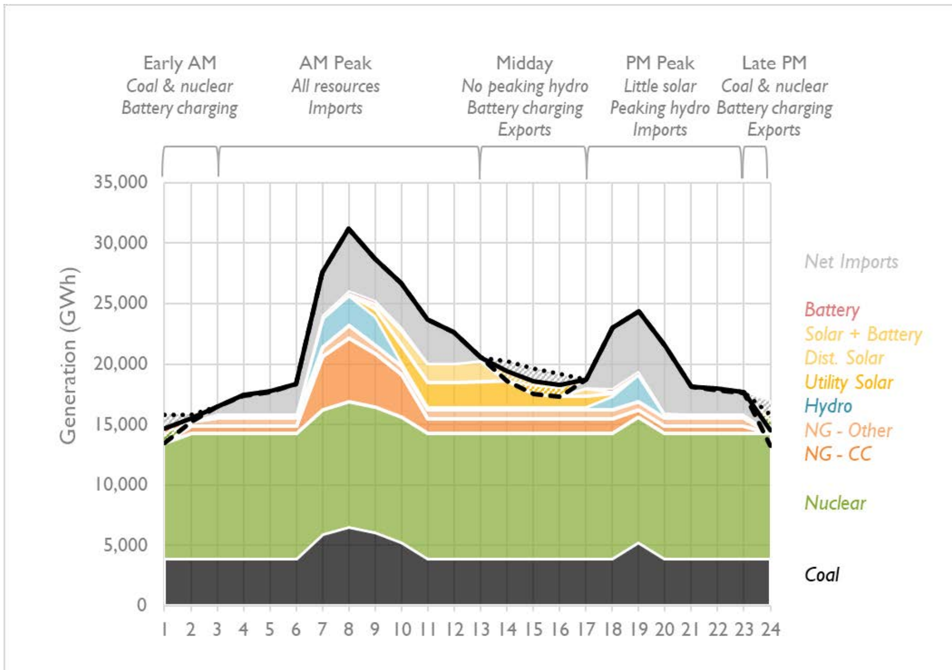
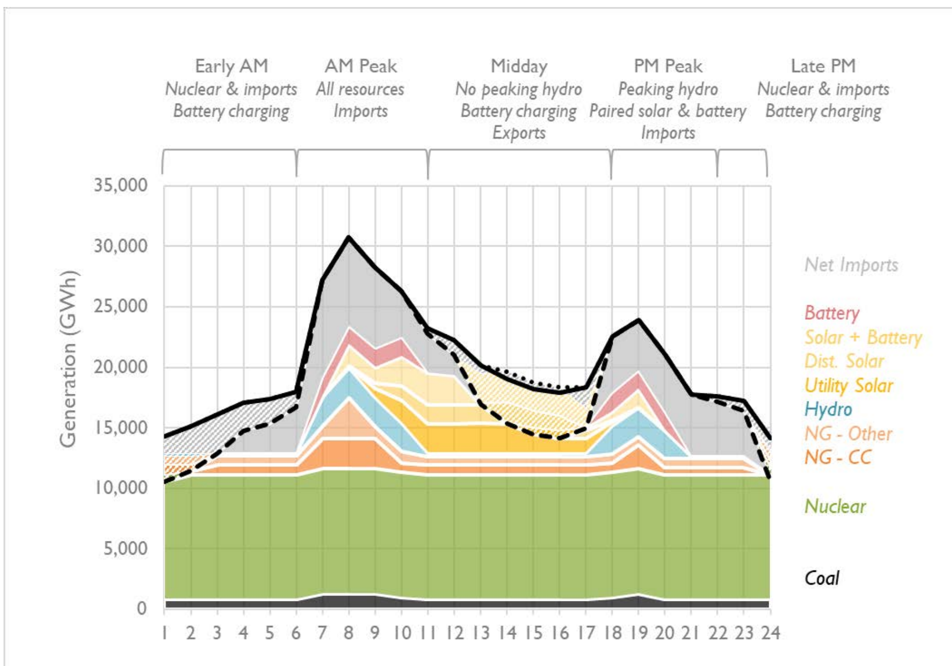
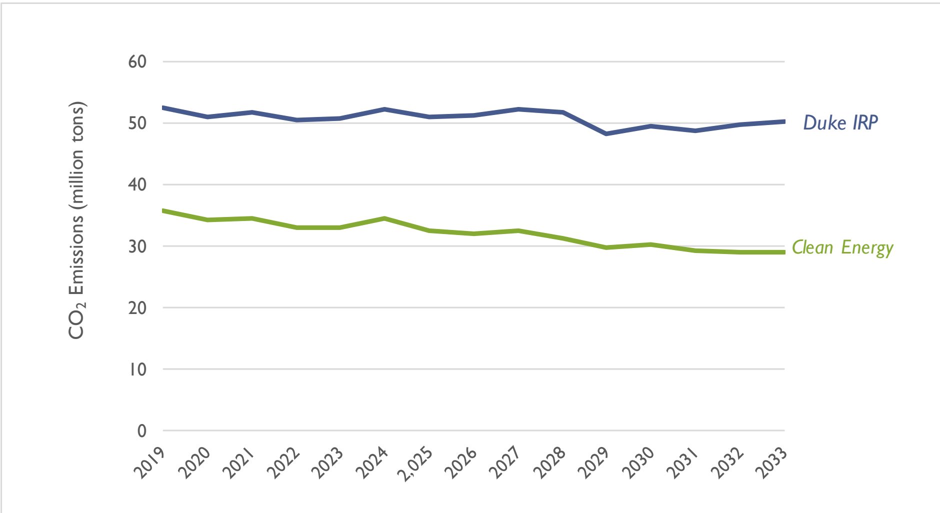


Figure 6. Sample winter peak generation by fuel type, January 3, 2028, Clean Energy scenario



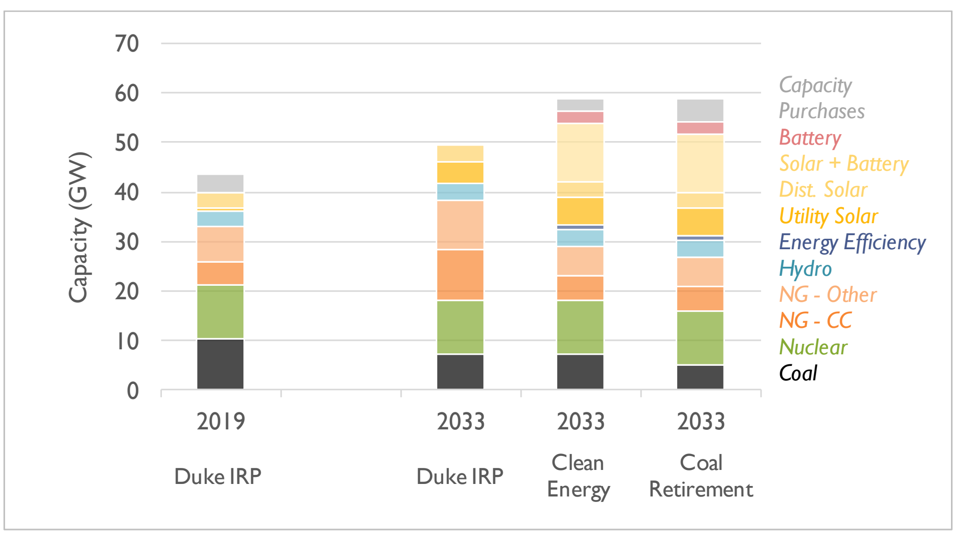
Finally, as expected based on the substantial difference in carbon-free capacity and generation between the two scenarios, the CO_2 emissions in the Clean Energy scenario are well below those in the Duke IRP scenario. The removal of the must-run coal designations immediately leads to a reduction in CO_2 emissions of almost 17 million tons in 2019. Though both scenarios see overall emissions decline, the gap between the two widens by the end of the period, when the Duke IRP scenario continues to emit almost 50 million tons of CO_2 while the Clean Energy scenario emits just under 30 million tons. Figure 7 depicts this widening gap, with both scenarios accounting for emissions associated with energy imports. Again, these volumes will differ from those reported by Duke Energy in Figure A-3 of each of its IRPs given the operational differences between generators that exist between the Company's modeled scenario and the Synapse Duke IRP scenario.

Figure 7. Duke Energy CO_2 emissions by year by scenario



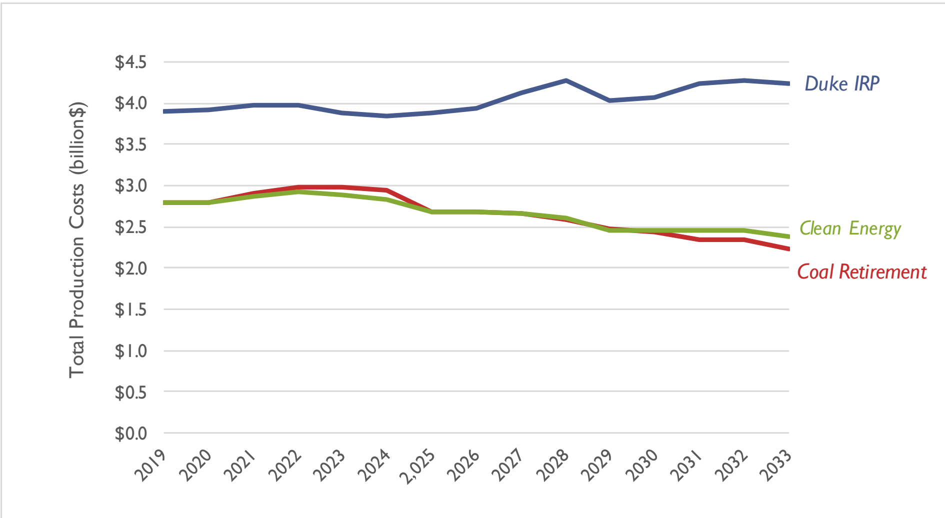
Synapse also examined an Accelerated Coal Retirement scenario in order to examine the ways in which advancing certain coal unit retirements changes system emissions and costs. This scenario accelerates Duke's retirement of the Roxboro Units 3 and 4 to December 2030 and the retirement of Marshall Units 1 and 2 to December 2032. As shown in Figure 8, the EnCompass model chooses to make up for the retired coal capacity through capacity purchases from surrounding states.

Figure 8. Duke Energy modeled nameplate capacity with Accelerated Coal Retirement, 2019 and 2033



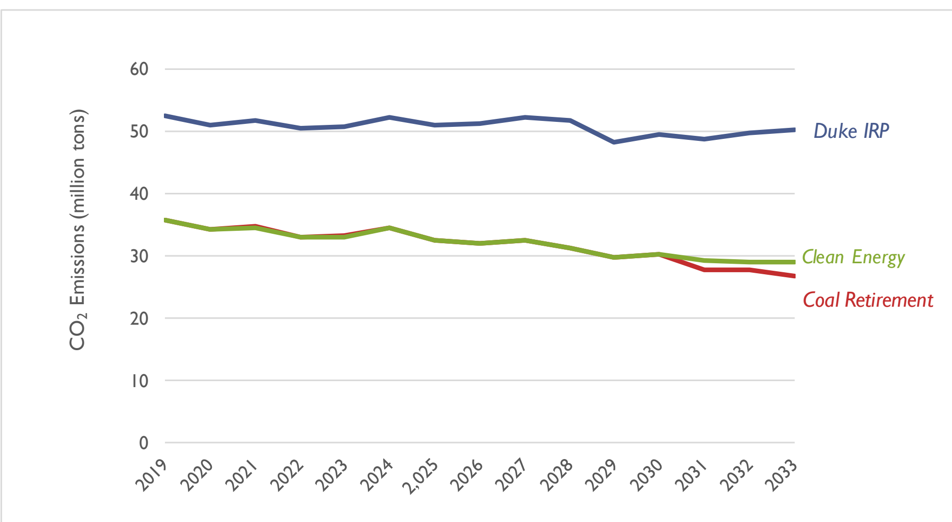
Production costs are extremely similar between the Clean Energy and Accelerated Coal Retirement scenarios, as shown in Figure 9. Costs drop slightly in the Accelerated Coal Retirement scenario in 2030 as the Roxboro 3 and 4 and Marshall 1 and 2 retirements move forward in time compared to the other scenarios. Energy imports increase slightly in the Accelerated Coal Retirement scenario as a replacement for the generation from these retiring units.

Figure 9. Duke Energy production cost by year by scenario



We see a comparable decrease in emissions after 2030 in the Accelerated Coal Retirement scenario, as shown in Figure 10.

Figure 10. Duke Energy CO_2 emissions by year by scenario



The following sections examine the impacts to human health, customer rates and bills, and state GDP and jobs of the Clean Energy scenario as compared to the Duke IRP scenario. Because the Clean Energy and Accelerated Coal Retirement scenarios were so similar, we limited our analysis to the differences between the Duke IRP and Clean Energy scenarios only.

3.2. Health Impacts

Synapse used the CO-Benefits Risk Assessment (COBRA) tool to assess the avoided health impacts in both North Carolina and South Carolina due solely to the change in emissions associated with our modeled Clean Energy scenario. Developed for the U.S. Environmental Protection Agency (EPA) State and Local Energy and Environment Program, COBRA utilizes a reduced form air quality model to measure the impacts of emission change on air quality and translates them into health and monetary effects. For this analysis, Synapse used modeled emissions (SO_2, NO_X, & $PM_{2.5}$) from the Duke IRP scenario as a baseline and compared them to modeled emissions from the Clean Energy scenario. The health and monetary benefits described below are those avoided by the Clean Energy scenario.

COBRA can estimate a number of detailed health impacts, including adult mortality, infant mortality, non-fatal heart attacks, respiratory hospital admissions, cardiovascular-related hospital admissions, acute bronchitis, upper respiratory symptoms, lower respiratory symptoms, asthma exacerbations, asthma emergency room visits, minor restricted activity days, and work loss days due to illness. A subset of those specific health impacts is shown in Table 1, with the numbers in the table representing the number of hospital visits and work loss days that could be avoided under the Clean Energy scenario.

Table 1. Avoided health impacts of the Clean Energy scenario

Year	Hospital Admits, Respiratory	Hospital Admits, Respiratory Direct	Hospital Admits, Asthma	Hospital Admits, Lung Disease	Hospital Admits, Cardio	Emergency Room Visits, Asthma	Work Loss Days
2020	6.0	4.3	0.5	1.2	7.1	10.8	2,398
2025	5.9	4.3	0.5	1.2	7.0	10.7	2,372
2030	4.9	3.5	0.4	1.0	5.8	8.9	1,966
2033	4.8	3.4	0.4	0.9	5.6	8.6	1,911

In 2020 the difference in Duke Energy's electric system dispatch in the Clean Energy scenario avoids approximately six respiratory-related hospital admits, seven cardiovascular-related hospital admits, and 11 asthma-related emergency room visits in North and South Carolina compared to the Duke IRP scenario. Notably, COBRA projects similar avoided health effects at the end of the modeling period (2033) compared to 2020. This is largely due to the removal of coal must-run designations in the Clean Energy scenario, which leads to an immediate decrease in emissions of air pollutants as coal generation drops. The Duke IRP scenario keeps uneconomic coal units online and, when not forced to generate, the Clean Energy scenario utilizes low-pollutant nuclear and renewable resources to generate in the place of coal. Thus, there is a sizeable difference in emissions between the two scenarios from the beginning of the period. The Duke IRP scenario slowly ramps down its reliance on coal-fired generation over the course of the analysis period, causing the gap in emissions avoided health impacts to narrow over time.

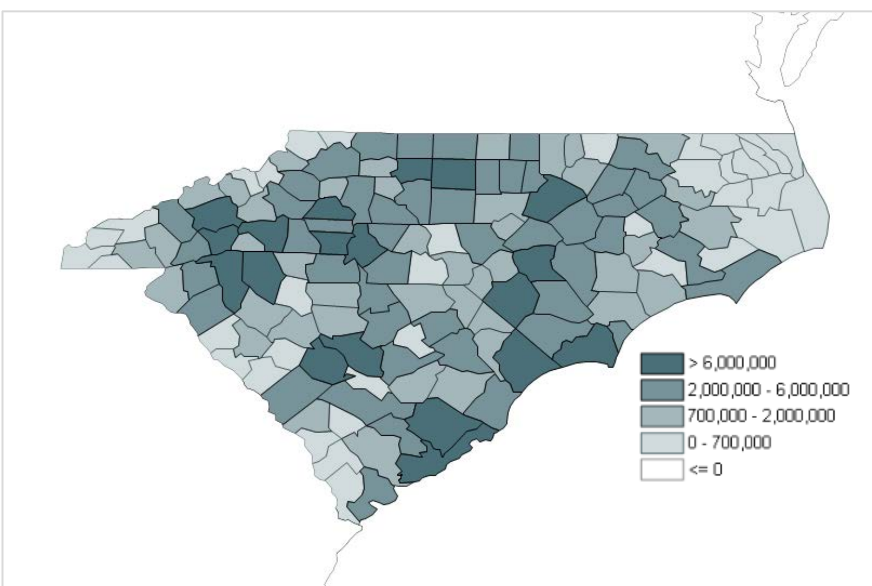
In addition to physical health effects and the costs of associated medical treatment, illnesses related to air pollution impose other costs on society, which include lost productivity and wages if a person misses work or school and restrictions on outdoor activity when air quality is poor. Table 2 shows low and high estimates of the monetized value of these total health benefits. These numbers place an economic value on all of the avoided health impacts modeled in COBRA, plus the value of minor restricted activity days and work loss days.

Table 2. Monetary benefits of all avoided health impacts under the Clean Energy scenario

Year	Total Health Benefits, Low	Total Health Benefits, High
2020	$196,778,415	$444,771,642
2025	$194,592,175	$439,830,666
2030	$161,291,821	$364,570,301
2033	$156,736,570	$354,274,856

The avoided health impacts and monetary benefits associated with the emissions reductions in the Clean Energy scenario vary by county, with the largest impacts seen in the most populous counties in North and South Carolina. Figure 11 shows the distribution of the monetized total health benefits across North and South Carolina in 2028. As one might intuit, greater benefits are realized in those counties with larger populations, where a larger number of people are affected by the local air quality.

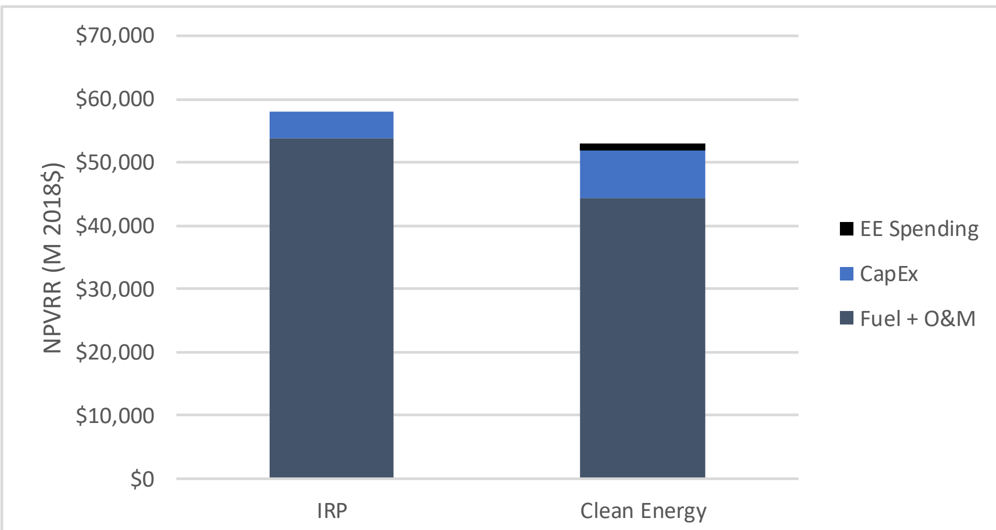
Figure 11. Total health-related monetary benefits ($ high estimate) of the Clean Energy scenario by county, 2028



3.3. Rate and Bill Impacts

Revenue requirements are lower under the Clean Energy scenario than in the IRP scenario, due primarily to the lower production cost associated with the operation of Duke's power plants. Capital expenditures in the IRP scenario are lower than in the Clean Energy scenario, as they represent only the cost of renewable procurement up to the levels specified by NC House Bill 589, along with North Carolina's portion of new, "optimized" combined-cycle and combustion turbine units added by Duke Energy post-2025. The Clean Energy scenario contains additional revenue requirements associated with capital spending on renewable resources over-and-above HB 589 levels and administration costs associated with incremental energy efficiency, but the fuel and operations and maintenance (O&M) savings from the operation of low- and no-variable cost resources lowers the total revenue requirement. These numbers do not include spending on transmission and distribution. Those revenue requirements are shown in Figure 12.

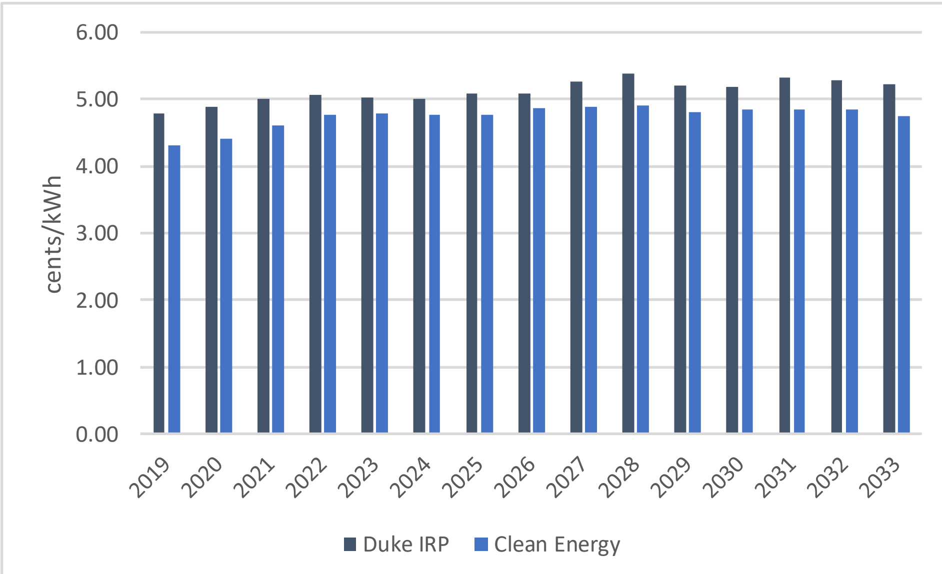
Figure 12. Revenue requirement of the Duke IRP and Clean Energy scenarios, North Carolina



Note that Duke Energy's capital cost assumptions were used for the resources in the IRP scenario. Synapse used capital costs for standalone solar and battery storage, wind, and paired solar and battery from NREL and Lazard. Duke's capital cost estimate for solar capacity from 2019 to 2033 is lower than the Synapse assumption, and the solar cost component of the capital spending revenue requirement is a conservative one.

Ratepayers in North Carolina save money under the Clean Energy scenario. Synapse calculated the estimated change in the rate components associated with capital spending and production costs. These values were taken from EnCompass and were allocated to North Carolina based on the percentage of Duke energy sales occurring in the state in 2017 according to EIA data. In the Clean Energy scenario, the increased spending on energy efficiency programs was added to this value. Total costs were then divided by Duke's energy sales to all customer classes to arrive at an average retail rate impact in each scenario that is associated with capital cost, production cost, and incremental energy efficiency spending.[5] We found that for any given year during the analysis period, ratepayers can expect to save anywhere from a minimum of .24 cents/kWh to a maximum of .48 cents/kWh, as shown in Figure 13, which translates to a savings of 4 to 9 percent over the study period.

Figure 13. Estimated average retail rate impact of the Duke IRP and Clean Energy scenarios



In order to estimate the total change in residential customers' electricity bills under the Clean Energy scenario, the average retail rate was multiplied by an assumed energy consumption by residential customers of 1,000 kWh per month, or 12,000 kWh per year. This was assumed to represent the component of residential rates associated with capital, fuel, variable O&M, and incremental energy efficiency spending (in the Clean Energy scenario). Costs associated with Transmission, Distribution, and Customer Charges were taken from slides 22 and 23 of the presentation entitled *North Carolina's Public Utility Infrastructure & Regulatory Climate* presented by the North Carolina Utilities Commission in October 2018.[6] A single weighted average of the sum of these costs for DEC and DEP was calculated based on the number of residential customers in each state, and was added to the capital/production cost component.

The lower production costs (fuel and variable O&M) in the Clean Energy scenario lead to immediate savings in customer electricity rates compared to the Duke IRP scenario. Under the Clean Energy scenario, North Carolina consumers also use less electricity under the Enhanced Energy Efficiency program. Lower electricity use,[7] coupled with the decrease in rates, causes residential consumers in the

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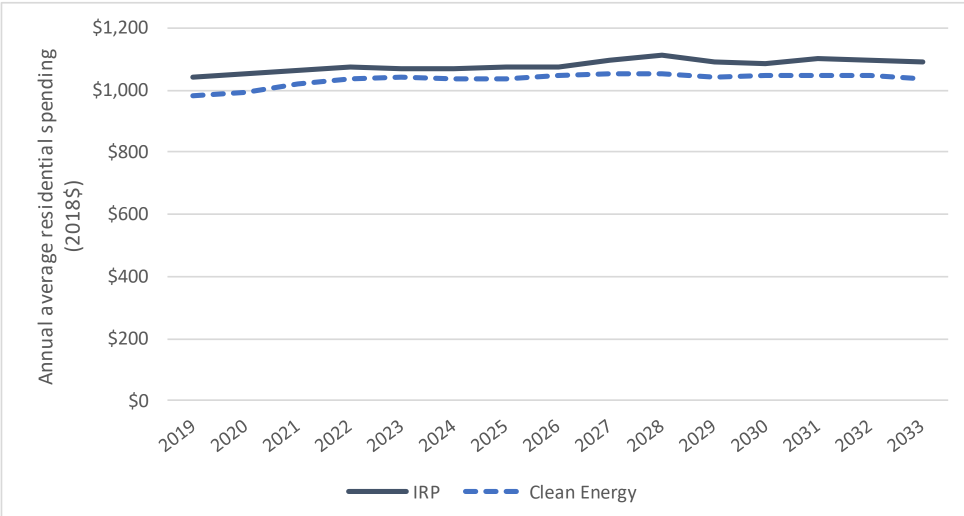
[5] For more information on the rate and bill impact calculation methodology, see Appendix A.

[6] This presentation is available at: https://www.ncuc.net/documents/overview.pdf

[7] Annual electricity use was calculated by dividing Duke Energy's forecasted energy sales by the forecasted customer count.

state see their average annual electricity costs decline by $27–$58 per year, or approximately 2.5 to 5.5 percent, depending on the year. This savings is shown in Figure 14.

Figure 14. Estimated residential bill impact of the Duke IRP and Clean Energy scenarios



3.4. Economic Impacts

Synapse used the IMPLAN model to evaluate the impacts of the Clean Energy scenario on employment, income, and Gross Domestic Product (GDP) in North Carolina. IMPLAN is an industry-standard model that can be used to evaluate the impacts of changes in direct spending patterns on a state's economy. For this analysis, North Carolina-specific spending impacts were determined by allocating Duke costs and spending based on North Carolina's proportion of system-wide energy sales. IMPLAN's framework enables us to assess not only impacts in directly affected industries, but also impacts on industries that serve as suppliers to directly impacted industries or that serve employees of directly and indirectly impacted industries. Synapse evaluated macroeconomic impacts resulting from changes in direct spending on the construction of each generation resource type, the operation of generation resources, and the installation of energy efficiency measures. We also assessed impacts associated with changes in disposable income among households and businesses facing lower (or higher) energy costs under the Clean Energy scenario.

Figure 15 displays the average annual North Carolina employment impacts of the Clean Energy scenario relative to the Duke IRP scenario in each of three five-year periods covering the IRP study timeframe. We find modest positive net positive employment impacts in each period, as positive impacts associated with re-spending of energy savings and increased spending on energy efficiency and renewable energy resources outweigh negative impacts associated with decreased spending on coal and natural gas power plants. Over the full IRP study period, our results indicate an average annual increase in North Carolina employment of approximately 3,000 full-time jobs.

Figure 15. Average annual employment impacts of Clean Energy scenario relative to Duke IRP scenario

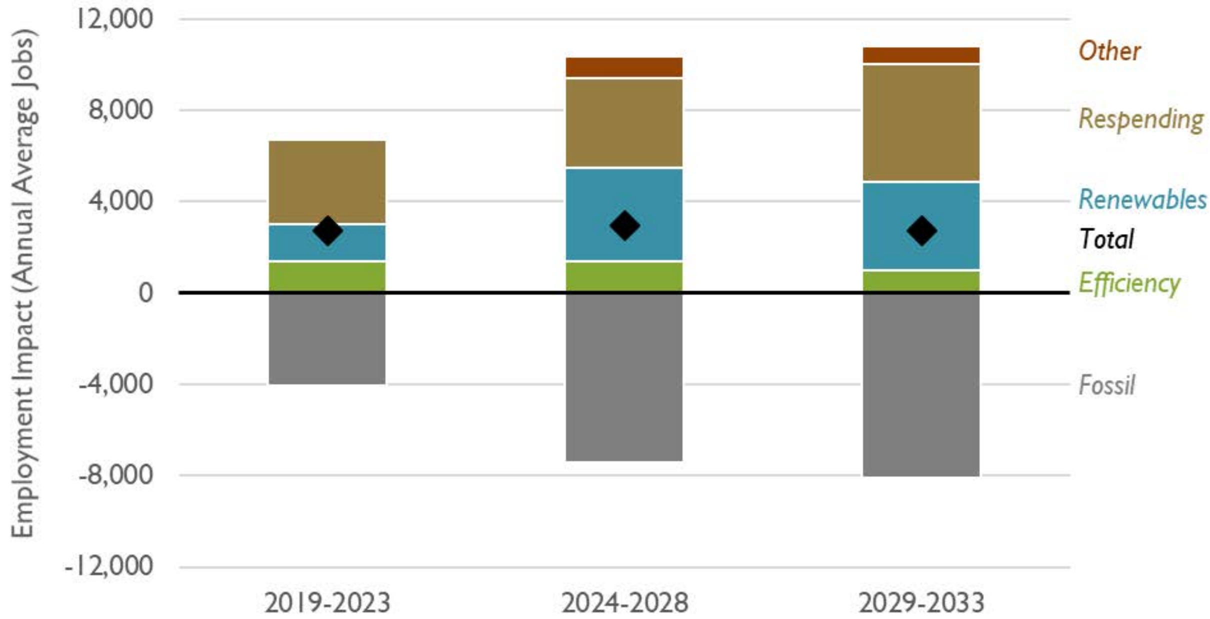


Figure 16 presents a similar picture regarding impacts on income of North Carolina residents. Our results indicate that the net increases in employment drive modest net increases in total income. Over the period from 2019 through 2023 we estimate net increases in average annual income of approximately $110 million.

Figure 16. Average annual income impacts of Clean Energy scenario relative to Duke IRP scenario

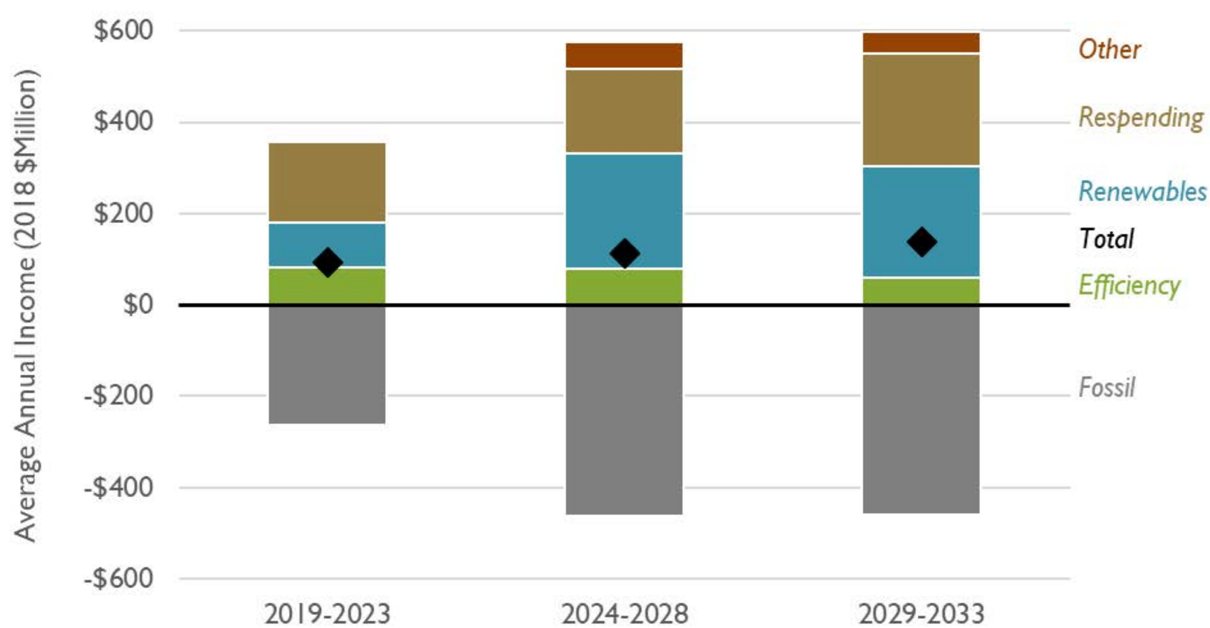
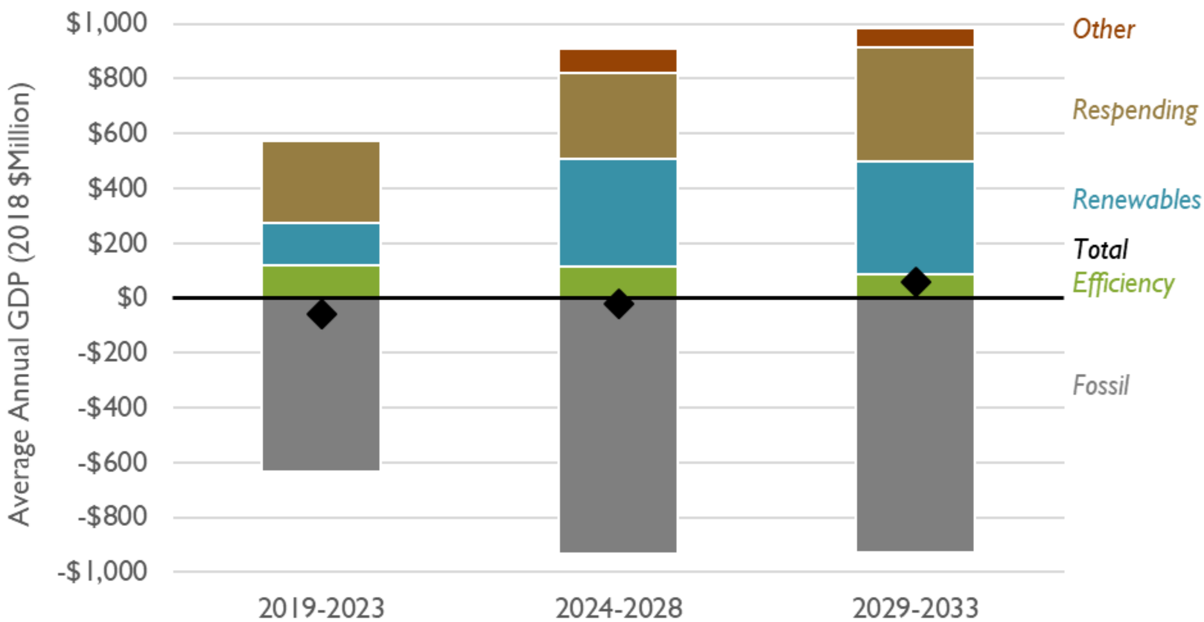


Figure 17 displays results for North Carolina state GDP. In this case, we find small net negative impacts, as GDP decreases associated with reduced spending on construction and operation of fossil fuel resources outweigh increases driven by greater spending on renewables, efficiency, and the wider economy. Over the period from 2019 through 2033 we find an average annual net GDP decrease of approximately $10 million. The discrepancy between this finding and our employment results reflects the fact that renewable resource and retail industries tend to be more labor-intensive than fossil fuel industries.

Figure 17. Average annual GDP impacts of Clean Energy scenario relative to Duke IRP



We note that all of these macroeconomic impacts are quite small in the context of North Carolina's economy. For example, our finding of an average annual employment increase of 3,000 amounts to less than 0.1 percent of the total number of jobs in North Carolina.[8] Similarly, an annual GDP impact of $10 million amounts to less than 0.01 percent of North Carolina's GDP.[9]

To summarize, Synapse performed a rigorous, scenario-based analysis to evaluate an alternative clean energy future compared to the more traditional portfolio of fossil-fueled resource additions included in Duke Energy's IRPs. In contrast to Duke's preferred resource portfolio, we found that the EnCompass model chooses to build out solar and storage resources to meet future capacity and energy needs with zero incremental natural gas-fired unit additions when allowed to select the most cost-effective future resource build. Coal generation declines between the Duke IRP and Clean Energy scenarios, lowering the

[8] Total employment in North Carolina is currently approximately 4.5 million. See https://www.bls.gov/news.release/laus.nr0.htm.

[9] 2017 North Carolina GDP was approximately $540 billion. See https://fred.stlouisfed.org/series/NCNGSP.

electric system production cost and reducing CO_2 emissions while maintaining system reliability. Our modeling shows that renewable resources are comparably cost-effective to new natural gas for North Carolina ratepayers and offer other benefits to consumers in the state, including a decrease in the number of hospital visits related to poor air quality, electricity rate and bill savings for consumers, and increased employment.

Appendix A. TECHNICAL APPENDIX

Synapse used EnCompass to model resource choice impacts in Duke's service territory in North and South Carolina. Developed by Anchor Power Solutions, EnCompass is a single, fully integrated power system platform that provides an enterprise solution for utility-scale generation planning and operations analysis. EnCompass is an optimization model that covers all facets of power system planning, including:

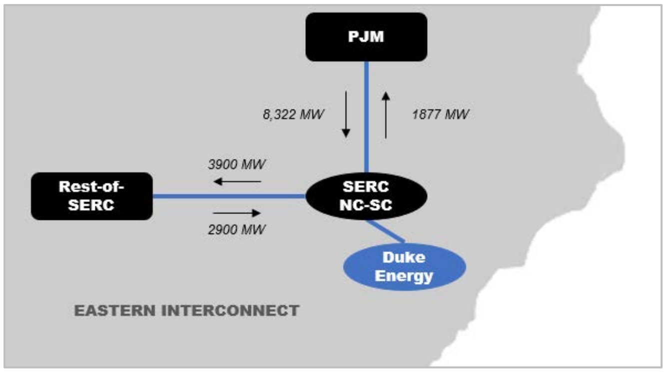
- Short-term scheduling, including detailed unit commitment and economic dispatch, with modeling of load shaping and shifting capabilities;
- Mid-term energy budgeting analysis, including maintenance scheduling and risk analysis;
- Long-term integrated resource planning, including capital project optimization, economic generating unit retirements, and environmental compliance; and
- Market price forecasting for energy, ancillary services, capacity, and environmental programs.

Synapse used the EnCompass National Database created by Horizons Energy to model the Duke service territory. Horizons Energy has benchmarked dispatch and prices resulting from its comprehensive dataset to actual, historical data across all modeling zones. More information on EnCompass and the Horizons dataset is available at www.anchor-power.com.

Topology and Transmission

Synapse modeled two detailed areas with full unit-level operational granularity, the Duke Energy utility service territory, and the remaining SERC region comprised of North Carolina and South Carolina. Additionally, we modeled external contract regions representing the SERC and PJM balancing areas. We relied on transmission assumptions from the EnCompass National Database, displayed in Figure 18 below. Energy transfers between SERC NC-SC and the Rest-of-SERC and PJM regions are subject to a default 3.44 $/MWh tariff. Capacity transfers are unlimited within SERC regions. Energy from the PJM and Rest-of-SERC regions are priced at recent historical energy prices and escalated throughout the period.

Figure 18. Duke IRP modeling topology and energy transfer capabilities



Peak Load and Annual Energy

For the Duke Energy territory, Synapse relied on annual energy and peak load as defined in the 2018 Duke Energy Carolinas and Duke Energy Progress IRPs. Synapse used annual energy and peak projections from the NERC Long-term Reliability Assessment for the SERC-NC-SC region. We utilized hourly load shapes supplied by Horizons Energy in the EnCompass National Database for all modeled regions. Synapse also performed analysis in the proprietary Electric Vehicle Regional Emissions and Demand Impacts Tool (EV-REDI)[10] to model the load required to meet the electric vehicle (EV) target set in North Carolina Executive Order No. 80 (80,000 EVs by 2025, and an annual 5 percent increase through the end of the period). The additional EV load is included in the Clean Energy scenario.

Fuel Prices

For natural gas prices, Synapse relied on NYMEX futures for monthly Henry Hub gas prices through December 2019. For all years after 2019, Synapse used the annual average prices projected for Henry Hub in the AEO 2018 Reference case. We then applied trends in average monthly prices observed in the NYMEX futures to this longer-term natural gas price to develop long-term monthly trends. Delivery price adders for Zone 5 are sourced from the EnCompass National Database. Coal prices, from the Central Appalachia supply basin, and for the Carolinas delivery point are also sourced from the EnCompass National Database. Gas and coal price forecasts are shown in Figure 19 and Figure 20 below.

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[10] More information on EV-REDI is available at: http://www.synapse-energy.com/tools/electric-vehicle-regional-emissions-and-demand-impacts-tool-ev-redi

Figure 19. Natural gas price forecast – Henry Hub and Zone 5 Delivery Point

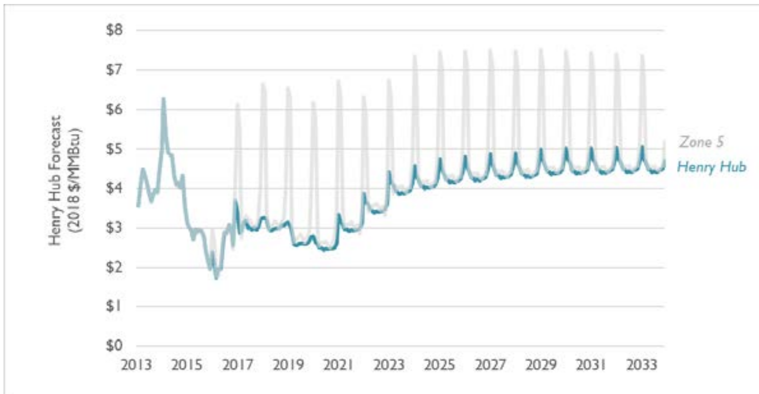
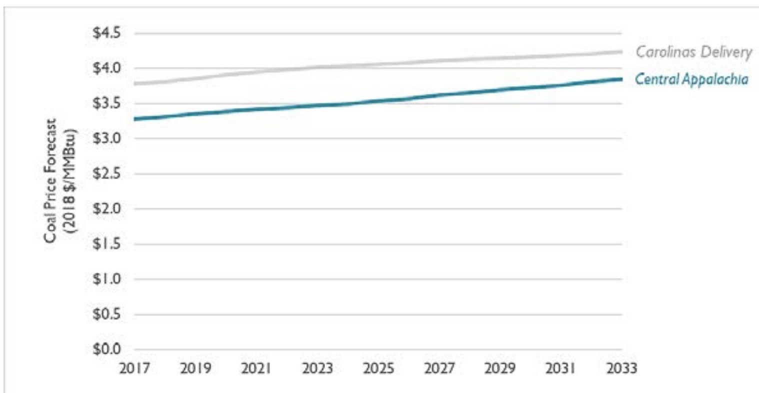


Figure 20. Coal price forecast – Central Appalachia Basin and Carolinas Delivery Point



Programs

Synapse modeled two major environmental programs: the North Carolina Renewable Energy & Energy Efficiency Portfolio Standard (REPS) and the carbon price forecast outlined in the 2018 Duke Energy IRPs. The REPS requires that 10 percent of electricity sales be met by renewable resources—stepping up to 12.5 percent in 2021—and up to 25 percent of the requirement can be met through energy efficiency technologies (40 percent after 2021). The carbon price outlined in the Duke IRPs begins at $5/ton (nominal) in 2025 and escalates at $3/ton annually.

Duke IRP Planned Resources

The Duke IRP scenario includes all planned additions, upgrades, and retirements described in the Duke IRPs, shown in Table 3 below, as well as generic combined cycle and combustion turbines added by the System Optimizer model in 2025 and beyond ("modeled additions").

Table 3. Duke IRP capacity (MW)

TYPE	PLANNED ADDITIONS	PLANNED RETIREMENTS	MODELED ADDITIONS
Coal		4,553	
CC	560	173	5,352
Hydro	260	1	
Nuclear	56		
CHP	81		
CT	402	843	3,220
Solar	673		
Storage	232		

Clean Energy Scenario Projects

For the Clean Energy scenario, Synapse allowed five generic project options in both North Carolina and South Carolina. They include onshore wind,[11] utility-scale battery, utility-scale solar, and a paired utility-scale battery and solar project. For these projects Synapse uses NREL's Advanced Technology Baseline projections and Lazard's Levelized Cost of Storage 2018 report to define cost and operational parameters.

Other Assumptions

Synapse made additional adjustments to our core modeling assumptions in consultation with the North Carolina Sustainable Energy Association. We list those assumptions below.

- In the Clean Energy scenario, the Duke territory has a required reserve margin of 15 percent, while the Duke IRP case uses the 17 percent reserve margin outlined in the Duke IRPs.
- Battery resources have a firm capacity credit of 75 percent throughout the analysis period, consistent with the recent study entitled *Energy Storage Options for North Carolina* and prepared by North Carolina State University.
- Coal must-run designations are applied in the Duke IRP scenario and are removed in the Clean Energy scenario.
- Energy efficiency is modeled as a supply-side resource in the Clean Energy scenario based on the Enhanced Energy Efficiency case described in the Duke IRPs. It is priced at the levels outlined in the *2016 Duke Energy North Carolina DSM Market Potential Study*.
- Carbon dioxide emissions associated with energy imports in each of the scenarios are calculated using a declining annual average emissions rate for generation in PJM. According to the region's emissions report *2013-2017 CO_2, SO_2 and NO_x Emissions*

[11] Offshore wind was not offered to the EnCompass model in Duke Energy's service territory. However, it was offered to the external NC-SC region and was not selected by the model.

Rates,[12] emissions of CO_2 have declined over the past five years. We applied this declining rate to the PJM System Average in 2017 to project future emissions rates. These rates were then multiplied by the volume of energy imports in each year, and calculated emissions were added to emissions from Duke's units to determine total annual CO_2 emissions from all sources.

COBRA Modeling Assumptions

The U.S. EPA's COBRA model contains baseline emissions estimates for the pollutants $PM_{2.5}$, SO_2, NO_x, NH_3, and VOCs for the year 2017. Users can adjust these estimates up or down, and the model utilizes a reduced form air quality model to estimate the effects of these emission changes on ambient particulate matter. It then calculates avoided health and monetary benefits associated with the emissions changes consistent with U.S. EPA practice. For more information visit https://www.epa.gov/statelocalenergy/co-benefits-risk-assessment-cobra-health-impacts-screening-and-mapping-tool.

To estimate the health and economic impacts of NO_X and SO_2, Synapse utilized annual emissions outputs from the EnCompass model scenarios for the Duke service territory in North and South Carolina. Emission rates were based on the following specific assumptions:

- EnCompass approximates NO_X and SO_2 emissions using unit-specific emission rates, as defined in the Horizons Energy National Database.
- For this project, Synapse incorporated an average $PM_{2.5}$ emissions rate for all coal fuels in EnCompass of 0.027 lb/mmBtu. This emissions rate is in line with emission rates compiled by Argonne National Laboratory for *GREET Model Emission Factors for Coal- and Biomass-fired Boilers* and by EPA for the Avoided Emissions and generation Tool (AVERT).

Synapse assumed a 7 percent discount rate for all COBRA analyses. Additionally, the COBRA analysis relies on historical county-level emissions allocations and assumes no county-level shifting.

Rate and Bill Impacts

Synapse used spreadsheet analysis to estimate the impact of the Clean Energy scenario on estimated electric rates and bills in North Carolina. Customer electric rates in a given year are made up of a number of components, including, but not limited to: utility capital expenditures inclusive of accumulated depreciation and an approved rate of return; the cost to a utility of generating the electricity necessary to meet customer demand; utility spending on any energy efficiency programs; and the volume of sales to customers.

[12] Available at: https://www.pjm.com/-/media/library/reports-notices/special-reports/20180315-2017-emissions-report.ashx?la=en

We determined utility capital expenditures for the Duke IRP scenario using Duke Energy's anticipated future resource portfolio and capital cost trajectories for the resource technologies added to its capacity mix. In their IRPs, DEC and DEP do not differentiate between new thermal capacity added in North Carolina versus South Carolina, and thus capital expenditures on new natural gas-fired resources were allocated to states based on the proportion of customer sales. Renewable additions were assumed to be necessary to comply with North Carolina HB 589 and capital expenditures were allocated to North Carolina ratepayers. In the Clean Energy scenario, the capital expenditures associated with the volume of renewable additions necessary for HB 589 was again allocated to North Carolina, with any capital expenditures from renewable additions above these volumes being allocated between North and South Carolina based on forecasted energy sales.

Production costs (fuel and fixed and variable O&M) in the two modeled scenarios were allocated between DEC and DEP based on forecasted energy sales. The volume of energy sales expected to occur in North Carolina versus South Carolina was calculated using the historical ratio of 2017 sales found in the most recent EIA 861 data. The historical percentage of sales occurring in North and South Carolina in DEC and DEP service territories was applied to the anticipated energy sales contained in the utilities' IRPs.

Program administration costs for energy efficiency are from the *2016 Duke Energy North Carolina DSM Market Potential Study* and the *2016 Duke Energy South Carolina DSM Market Potential Study*, both done by Nexant Consulting.

Estimated average retail rates were calculated by summing anticipated capital expenditures, production costs, and incremental utility energy efficiency costs, and dividing by total sales in North Carolina. Though actual rates differ between different customer classes, for the sake of this analysis we assumed one standard electricity rate across customer classes, referred to in the text as the "average retail rate."

In order to estimate the total change in residential customers' electricity bills under the Clean Energy scenario, the average retail rate was multiplied by an assumed energy consumption by residential customers of 1,000 kWh per month, or 12,000 kWh per year. This was assumed to represent the component of residential rates associated with capital, fuel, variable O&M, and incremental energy efficiency spending (in the Clean Energy scenario). Costs associated with Transmission, Distribution, and Customer Charges were taken from slides 22 and 23 of the presentation entitled *North Carolina's Public Utility Infrastructure & Regulatory Climate* presented by the North Carolina Utilities Commission in October 2018. A single weighted average of the sum of these costs for DEC and DEP was calculated based on the number of residential customers in each state, assumed to grow at real rate of 2 percent per year, and was added to the capital/production cost component.

Modeling Economic Impacts

The differences in capacity, generation, emissions, and system costs between the Clean Energy and Duke IRP scenarios drive differences in employment, income, and state Gross Domestic Product (GDP). Synapse used the IMPLAN model to evaluate the impact of the Clean Energy scenario on each of these macroeconomic indicators in North Carolina.[13] IMPLAN is an industry-standard input-output model that relies upon historical economic relationships to evaluate the effects of changes in direct spending patterns on employment, income, and GDP within a given study area. For this analysis, Synapse assessed impacts resulting from changes in spending on the following economic activities:

- Construction of generating resources
- Installation of energy efficiency measures
- Operation and maintenance of generation resources
- Consumer and business re-spending of energy savings

Our analysis accounts for three types of impacts: direct, indirect, and induced.

Direct impacts

Direct impacts consist of changes in employment, income, and GDP within energy resource sectors immediately impacted by the change in resource plan between the Duke IRP and Clean Energy scenarios. For example, direct employment impacts may consist of additional jobs for contractors, construction workers, and plant operators working on the building or operation of a power plant.

Indirect impacts

Indirect impacts are changes in employment, income, and GDP within sectors that serve as suppliers to directly affected industries. Examples of such sectors include turbine manufacturers and manufacturers of energy-efficient appliances. Note that our analysis only accounts for impacts among suppliers located within North Carolina.

Induced impacts

Induced impacts result from residents spending more or less money in the local economy. For energy resources, these impacts result from: (1) changes in disposable income among employees in directly and indirectly impacted industries and (2) changes in energy expenditures by North Carolina electricity customers.

Direct inputs to our economic impact modeling consist primarily of vectors of changes in spending by and on various industries. These inputs are generally direct outputs from our EnCompass modeling. They include changes in spending on the construction and operation of each type of electricity resource (e.g., natural gas power plants, solar power plants, battery storage facilities). For each industry, Synapse

[13] IMPLAN is a commercial model developed by IMPLAN Group PLC. Information on IMPLAN is available at: http://implan.com/.

allocated the total change in spending across the available IMPLAN industry categories based on data from the National Renewable Energy Laboratory's JEDI model[14] and supplemental Synapse research.

[14] Available at: https://www.nrel.gov/analysis/jedi/

Appendix B. Qualifications and Experience

About Synapse

Synapse Energy Economics is a research and consulting firm specializing in energy, economic, and environmental topics. Since its inception in 1996, Synapse has grown to become a leader in providing rigorous analysis of the electric power sector for public interest and governmental clients.

Synapse's staff of 30 includes experts in energy and environmental economics, resource planning, electricity dispatch and economic modeling, energy efficiency, renewable energy, transmission and distribution, rate design and cost allocation, risk management, benefit-cost analysis, environmental compliance, climate science, and both regulated and competitive electricity and natural gas markets. Several of our senior-level staff members have more than 30 years of experience in the economics, regulation, and deregulation of the electricity and natural gas sectors. They have held positions as regulators, economists, and utility commission and ISO staff.

Services provided by Synapse include economic and technical analyses, regulatory support, research and report writing, policy analysis and development, representation in stakeholder committees, facilitation, trainings, development of analytical tools, and expert witness services. Synapse is committed to the idea that robust, transparent analyses can help to inform better policy and planning decisions. Many of our clients seek out our experience and expertise to help them participate effectively in planning, regulatory, and litigated cases, and other forums for public involvement and decision-making.

Synapse's clients include public utility commissions throughout the United States and Canada, offices of consumer advocates, attorneys general, environmental organizations, foundations, governmental associations, public interest groups, and federal clients such as the U.S. Environmental Protection Agency and the Department of Justice. Our work for international clients has included projects for the United Nations Framework Convention on Climate Change, the Global Environment Facility, and the International Joint Commission, among others.

Relevant Experience

Modeling Gas-Fired Plant Alternatives in New Mexico

Client: Sierra Club | Project ongoing

On behalf of the Sierra Club, Synapse is performing modeling of the electric system in New Mexico using the EnCompass model in both capacity expansion and production cost modes. Synapse is comprehensively modeling zero-emission alternatives to a new utility-proposed gas-fired generation option intended to replace the retiring San Juan Generating Station units in New Mexico in 2023. The modeling accounts for the interconnectedness of the electric power grid in the Desert Southwest region, including detailed representation of generation units in Arizona and New Mexico (and portions of Texas and California), and aggregated treatment for resources in the rest of the West. Synapse has found that a combination of utility-scale and small-scale solar PV, utility-scale battery storage, and incremental wind resource procurements would provide Public Service of New Mexico with a less-expensive, and lower-emitting alternative than its proposed gas-fired generation, while meeting all reliability requirements.

Nova Scotia Power Generation Utilization and Optimization Study

Client: Nova Scotia Utility and Review Board | Project completed August 2018

Synapse was asked to conduct an Integrated Resource Planning-type analysis on the overall utilization and optimization of Nova Scotia Power's coal and thermal generating fleet. Synapse used the PLEXOS electric sector simulation model for both capacity expansion and production cost purposes to estimate the costs associated with various unit retirement pathways and resource replacement options.

Value of Solar Implications of South Carolina Electric & Gas Fuel Costs Rider 2018

Client: Southern Environmental Law Center | Project completed May 2018

Synapse provided analysis and expert testimony on behalf of the South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy for South Carolina Electric & Gas' (SCE&G) 2018 annual update of solar PV avoided costs under PURPA. Witness Devi Glick submitted testimony (Docket no. 2018-2-E) regarding the appropriate calculation of benefit categories associated with the value of solar calculation for PURPA QF rates and for Act 236 compliance.

Avoided Energy Supply Costs in New England

Client: AESC Study Group | Project completed March 2018

Synapse and a team of subcontractors used EnCompass and other tools to develop projections of electricity and natural gas costs that would be avoided due to reductions in electricity and natural gas use resulting from improvements in energy efficiency. The 2018 report provides projections of avoided costs of electricity and natural gas by year from 2018 through 2035 with extrapolated values for another 15 years. In addition to projecting the costs of energy and capacity avoided directly by program participants, the report provides estimates of the Demand Reduction Induced Price Effect (DRIPE) of efficiency programs on wholesale market prices for electric energy, electric capacity, and natural gas. The report also provides a projection of avoided costs of fuel oil and other fuels, non-embedded environmental costs associated with emissions of CO_2, avoided costs of transmission and distribution, and the value of reliability. The 2018 AESC study was sponsored by a group representing all of the major electric and gas utilities in New England as well as efficiency program administrators, energy offices, regulators, and advocates. Synapse conducted prior AESC studies in 2007, 2009, 2011, and 2013.

Clean Energy for Los Angeles

Client: Food & Water Watch | Project completed March 2018

The Los Angeles City Council has mandated that the Los Angeles Department of Water and Power (LADWP), the largest municipally run utility in the United States, analyze powering 100 percent of demand with renewable energy. To date, LADWP's efforts have been insufficient, as the utility has only published an analysis of a slight increase over current renewable energy targets and is not planning to finalize its 100 percent renewable study until 2020 at the earliest.

Food & Water Watch engaged Synapse to analyze a potential pathway to 100 percent clean energy in Los Angeles by 2030 using the EnCompass model. The modeled scenarios in the *Clean Energy for Los Angeles* report include a substantial amount of storage capacity. The two 100 percent renewable scenarios build between 2 and 3 gigawatts of storage capacity which is dispatched liberally in order to shift generation from solar resources to meet demand in the region. Our analysis included hourly modeling that demonstrated exactly how storage could be charged and dispatched over the course of the day to meet the utility's needs.

In our study, we found that it is possible for LADWP to exclusively use renewable resources to power its system in every hour of the year. What's more, we found that under one of the clean energy pathways analyzed, the transition to 100 percent renewable energy in every hour of the year can occur at no net cost to the system. The resulting report, *Clean Energy for Los Angeles*, provides a roadmap for how to achieve 100 percent renewables by integrating and harnessing renewable energy more efficiently and investing in additional efficiency, storage, and demand response.

Although the report only focuses on a single city, the results are important and applicable to many other parts of the country. Los Angeles's four million residents make the city larger than 22 entire states, while the annual energy served by LADWP is greater than sales in 13 individual states, indicating that if this transition is possible in Los Angeles, it is feasible in other parts of the country as well.

An Analysis of the Massachusetts RPS
Client: E4theFuture | Project completed August 2017
Synapse Energy Economics joined with Sustainable Energy Advantage (SEA), as well as members from NECEC, Mass Energy Consumers Alliance, E4theFuture, and other organizations to analyze the current state of regional renewable portfolio standards in light of many of new policy actions that have been put into place over the last several years. These policy actions include new legislation requiring long-term contracting for renewables and other resources in Massachusetts, Connecticut, and Rhode Island, revised incentives for distributed generation resources, changes to RPS polices in other states in New England, proposed Massachusetts-specific CO_2 caps, and newly-revised forecasts for electricity sales that take the full impact of new energy efficiency measures into account. The Synapse team used the EnCompass model for this analysis.

Clean Power Plan Reports and Outreach for National Association of State Utility Consumer Advocates
Client: National Association of State Utility Consumer Advocates | Project completed August 2015
Synapse supported the National Association of State Utility Consumer Advocates and its members in addressing the EPA's proposed Clean Power Plan in a manner that is cost-effective and efficient from an electricity consumer perspective. Prior to the release of the rule, Synapse presented to NASUCA members key issues regarding the details of the proposed rule and the primary compliance options that may be available to states. Following the rule's release, Synapse prepared a report focusing on the details of the rule as proposed. Recognizing that stakeholders have a wide range of reactions to the EPA's Plan, the intent of the report is to be a common resource to help all of NASUCA's members think through a broad range of potential implications of various compliance approaches to their respective consumers—whatever their individual state's positions. Synapse presented on the findings

of *Implications of EPA's Proposed "Clean Power Plan"* at the 2014 NASUCA annual meeting in San Francisco, CA.

Synapse used its Clean Power Plan Planning Tool (CP3T) to perform multi-state analysis of the proposed rule to identify and explain a variety of challenges and opportunities related to multi-state compliance, including how states with dissimilar renewable technical potential, states with utilities that cross state boundaries, states with existing mechanisms for cooperation, etc., may approach regional compliance with the Clean Power Plan. Pat Knight, the lead developer of CP3T, provided a webinar for NASUCA members giving an overview of key issues surrounding the Clean Power Plan, as well as a walkthrough of CP3T's multi-state functionality. Synapse also prepared a report presenting the results of the analysis, presented at the NASUCA 2015 Mid-Year Meeting.

As a third element of Synapse's Clean Power Plan support to NASUCA members, Synapse prepared a report on best practices in planning for implementation of the Clean Power Plan. The report serves as a guide for consumer advocates to the logistics of developing a state implementation plan, with advice in areas such as stakeholder engagement, evaluating resource options, deciding on reasonable assumptions, identifying appropriate modeling tools, and selecting and implementing a plan.

Long-Term Procurement Plan Rulemaking
Client: California Office of Ratepayer Advocates | Project ongoing
Synapse is providing technical and expert witness services to the California Office of Ratepayer Advocates in connection with the Long-Term Procurement Plan proceeding affecting the three largest investor-owned utilities in California: Southern California Edison, Pacific Gas and Electric, and San Diego Gas and Electric. As part of this project, Synapse conducted modeling of the California ISO (CAISO) area using PLEXOS to assess loads and emissions throughout California based on various California Public Utilities Commission scenarios. Synapse analyzed model inputs, assumptions, forecast projections, and outputs, and examined alternatives including renewable energy integration and retirement scenarios. Synapse's modeling enabled determination of areas within California that would be capacity constrained.

Best Practices in Electric Utility Integrated Resource Planning
Client: Regulatory Assistance Project | Project completed June 2013
Synapse prepared a report for the Regulatory Assistance Project examining best practices in electric utility integrated resource planning. Synapse researched and discussed specific integrated resource plan (IRP) statutes, regulations, and processes in Arizona, Colorado, and Oregon; examined "model" utility IRPs from Arizona Public Service, Public Service Company of Colorado, and PacifiCorp; and developed recommendations for prudent integrated resource planning. Our report provided recommendations for both the IRP process and the elements that are analyzed and included in the resource plan itself. These elements include load forecast, reserves and reliability, demand-side management, supply options, fuel prices, existing resources, and environmental costs and constraints, among others.

Attachment 2

DUKE ENERGY CAROLINAS, LLC

Request:

Please describe how PPAs for energy and capacity between DEC and Qualifying Facilities (both compliance and non-compliance) that expire within the planning period are handled. Are these PPAs considered renewed after their initial terms?

Response:

In general, compliance and non-compliance qualifying facilities are expected to expire when the purchase power agreement terminates. For planning purposes, QF PPAs are expected to be either renewed or replaced in kind. Importantly, however, there is no explicit or implicit assumption in the IRP of contract renewals with any given existing QF facility owner.

DUKE ENERGY PROGRESS, LLC

Request:

Please describe how PPAs for energy and capacity between DEP and Qualifying Facilities (both compliance and non-compliance) that expire within the planning period are handled. Are these PPAs considered renewed after their initial terms?

Response:

In general, compliance and non-compliance qualifying facilities are expected to expire when the purchase power agreement terminates. For planning purposes, QF PPAs are expected to be either renewed or replaced in kind. Importantly, however, there is no explicit or implicit assumption in the IRP of contract renewals with any given existing QF facility owner.

NC Clean Energy Plan Scenario Analysis Using Temoa

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Background

Executive Order 80, titled "North Carolina's Commitment to Address Climate Change and Transition to a Clean Energy Economy", was passed on October 29, 2018 by Governor Roy Cooper. The Order has three goals: Reduce statewide greenhouse gas emission levels to 40% below 2005 levels by 2025; increase the number of registered, zero emission vehicles (ZEVs) to 800,000 by 2025; and reduce energy consumption per square foot in state-owned buildings to 40% below fiscal year 2002-2003 levels by 2025. The Order calls upon several agencies to meet these objectives.

Our team conducted model-based analysis to help inform Section 4 of EO80, which concerns the development of a Clean Energy Plan, which will help achieve the first goal of the Order.

Tools for Energy Model Optimization and Analysis (Temoa)

We utilized Tools for Energy Modeling Optimization and Analysis (Temoa) to complete the scenario analysis described here. A key feature of Temoa is that all model code and input data are open source, and can be accessed through our GitHub repositories (TemoaProject, 2019a). Access to code and data allows third parties to scrutinize our assumptions and replicate our results. We think it is an important feature of models aimed at informing policy.

Temoa is an energy systems optimization model that performs linear optimization to identify the least-cost pathway for energy system development. The energy system within Temoa is structured as a network in which technologies are linked together by a flow of energy commodities. Each technology has a set of engineering-economic characteristics, including capital cost, fixed and variable operations and maintenance costs, conversion efficiencies, and emissions coefficients. The model objective function minimizes the system-wide present cost of energy supply over a user-specified time horizon by optimizing the installation and utilization of energy technologies across the system. The model also includes a variety of constraints that ensure realistic energy system performance. Hunter et al. (2013) provides the full model formulation, which have since been updated (Temoa, 2018).

A key feature of Temoa is that the model code and input datasets are independent. As such, the model can operate on any compatible input dataset. The input dataset developed for this analysis is focused on the Duke Energy Progress and Duke Energy Carolina territories, which cover most of

North Carolina and a large section of South Carolina. We elected to model this territory rather than just North Carolina, as the former better reflects system-level operation. More details on the input data are given in the next section.

Input Data

The model time horizon extends from a base year of 2017 to 2050, where the years 2020 - 2050 are modeled as 5-year time periods. To represent variations in supply and demand at the sub-annual level, each year is composed of different time slices, which represent different combinations of seasons and times-of-day. In this database, we model a representative 24-hour diurnal profile for each season, resulting in a total of 96 time slices over which electricity supply and demand must be balanced.

Key elements of the input data are described below in Table 1. A copy of the input SQLite database containing the base case values is publicly available from GitHub (TemoaProject, 2019b).

Data Element	Description and Sources
Electricity demand	We assume that electricity demand will increase at an annual rate of 1.2%. Historical DEC and DEP electricity consumption in 2017 is used as the base year (Duke 2018a, 2018b). Electricity demand for Duke's balancing territory is larger than that of North Carolina, so results are scaled proportionally to represent electricity supply in North Carolina.
Existing generating capacity	Information on existing capacity comes primarily from EIA 860 data, which provided us with generator vintage and current installed capacity. Rather than individual generating units, existing capacity is described by plant number.
Capital and operating costs for new capacity	Capital and operating costs for new capacity come from NREL's Annual Technology Baseline for 2018 (NREL, 2018).
Availability factors	Availability factors are given for each technology for every hour of the day. Values come from either MARKAL (2014) or, in the case of solar PV, the NREL System Advisory Model.
Capacity credits	Capacity credits are defined as the contribution to peak demand made by each generating technology. Renewable energy capacity credits are derived from the DEC and DEP Integrated Resource Plans. Duke provides a 20% capacity credit for new wind and 5% for new solar capacity. Values for thermal generators are from NERC (2017). The capacity credit for four-hour lithium ion battery storage is based on the ECP values defined in Sioshansi et al. (2014).

Scenario Descriptions

Below are brief descriptions of the scenarios that we ran. Most of these scenarios were provided by the NC Department of Environmental Quality (DEQ). A few additional scenarios were completed to further explore the sensitivity of key baseline assumptions, such as the remaining lifetime of existing nuclear capacity.

Scenario Name	Scenario Description
S01	**Reference Case**. Business-as-usual base case. Our assumptions are derived from a variety of sources. The 2018 Duke Energy Integrated Resource Plans estimate 1.2% annual growth in electric demand. The Annual Technology Baseline (ATB) published in 2018 by NREL provided us with new technology costs. Fuel prices mostly come from the EIA Annual Energy Outlook (AEO), though some future coal prices were provided by DEQ. Plant heat rates came from data provided by EIA Form 923. House Bill 589 requires investments in solar by 2020 and 2025, so in all scenarios at least 3.3 GW of solar are on the grid in 2025 regardless of whether it is cost-optimal.
S01A	**High Natural Gas Price.** Same as the reference case, except we follow the EIA AEO high natural gas price forecast through 2050.
S01B	**Low Solar PV Cost.** Same as the reference case, except with modified utility-scale solar PV investment costs. The updated costs represent the low-cost trajectory in the 2018 NREL ATB.
S01C	**High Solar PV Cost.** Same as the reference case, except with modified utility-scale solar PV investment costs. The updated costs require solar capital costs to remain at their estimated 2017 values through 2050.
S02A	**Policy 2a.** Full adherence to HB 589 plus double the potential for energy efficiency improvements. Currently, North Carolina has to achieve a 12.5% Renewable Energy Portfolio Standard (REPS) by 2022. Currently, 40% of the REPS can be satisfied by improvements in energy efficiency (EE), which equates to 5% of total electricity demand. In this scenario, EE can account for up to 10% of demand. The minimum required renewables (excluding EE) share is 7.5%.
S02B	**Policy 2b.** This is an extension to the requirements of Policy 2a, but in addition, 2 gigawatts (GW) of offshore wind capacity are required to come online by 2025. These 2 GW are assumed to be distributed throughout Duke territory, including off the coast of South Carolina.
S03A	**Policy 3a.** This is an extension to the requirements of Policy 2a, but in addition, a standard 2% annual growth in solar capacity is required through 2020. To accompany this additional solar, 1 GW of lithium ion battery storage is required to come online by 2030. This 1 GW is assumed to be distributed throughout Duke territory, including South Carolina.
S03B	**Policy 3b.** All of the Policy 3a requirements are active, and in addition 2 GW of offshore wind is required to come online by 2030. These 2 GW are assumed to be distributed throughout Duke territory, including off the coast of South Carolina.
S03C	**Policy 3c.** All of Policy 3b requirements are active, and in addition 5 GW of Li-ion storage capacity are required by 2030. These 5 GW are assumed to be distributed throughout Duke territory, including South Carolina.
S03D	**Policy 3d.** All of Policy 3c requirements are active, except 5.5 GW of offshore wind are built by 2030 instead of 2 GW. These GW are assumed to be distributed throughout Duke territory, including South Carolina.
S04A	**Mild Carbon Cap.** This scenario adds a limit on the amount of state-wide carbon dioxide that can be emitted from the power sector. S04A limits emissions to 35 MMT from 2025 onward. There is no assumed trading in this case and leakage effects are ignored.

S04B	**Medium Carbon Cap.** This is a variant of S04A with a carbon cap of 30 MMT from 2025 onward.
S04C	**Stringent Carbon Cap.** This is a variant of S04A with a carbon cap of 25 MMT from 2030 onward.
S05	**Clean Energy Standard.** In this scenario, 60% of the electricity generated in North Carolina must come from clean energy sources by 2030 and beyond. This includes renewable energy technologies such as solar, wind, biomass, and landfill gas, as well as nuclear energy and fossil fuels with carbon capture and sequestration (CCS).
S06	**Extended Nuclear Case.** In this scenario, existing nuclear plant lifetimes have been extended to 80 years from 60 years. With 60-year lifetimes, all of North and South Carolina's nuclear fleet retires by the end of 2040. By keeping these plants online an additional 20 years, significantly fewer capital investments are necessary through 2050.
S07A	**1% ZEV Adoption.** In this scenario, we assume that 1% of vehicle miles traveled are from electric vehicles, increasing electricity demand during off-peak hours. We assume 116 billion vehicle miles traveled per year in NC (US DOT, 2016) through 2050 and use an efficiency of 4 miles/kWh for EV electricity consumption.
S07B	**5% ZEV Adoption.** Same as S07A, except the EV adoption rate is increased to 5%.
S07C	**10% ZEV Adoption.** Same as S07A, except the EV adoption rate is increased to 10%.

Results

Figures 1-3 present key results pertaining to electricity generation and capacity as well as emissions. Figures A-C in the appendix provide additional details. Key insights drawn from these figures pertaining to technology deployments are given below.

- **Utility scale solar photovoltaics and natural gas plants consistently increase their share of generation across the modeled scenarios.** Deployments of these technologies grow in response to increasing demand, nuclear retirements, and their greater cost-effectiveness compared to coal. Projected declines in solar PV capital costs help drive their deployment through mid-century. With respect to natural gas, the results suggest that combined-cycle units are more cost-effective than simple cycle turbines given their higher thermal efficiency.
- **The scale of solar PV, battery, and gas plant expansion depends on how long the existing nuclear fleet remains operational.** We assume that existing nuclear plants have a 60-year lifetime from their initial construction, except in the S06 scenario where existing nuclear plant lifetimes are extended from 60 to 80 years. Large differences in grid mix and carbon intensity of the grid are seen depending on these plant lifetimes.
- **The deployment of lithium-ion battery storage is observed in all six scenarios shown in Figure 1.** Battery costs are projected to decrease rapidly, and those cost declines are required to make battery storage cost-effective for bulk energy time shifting and peak capacity deferral. Across all modeled scenarios, battery storage is deployed in 2030 or later.
- **Offshore and onshore wind are generally not cost-effective.** Through 2030, no onshore wind is deployed, and offshore wind is only deployed in four of the eighteen scenarios we examined. In these scenarios, the offshore wind capacity is forced online through policy.

- **Across all scenarios, coal is becoming an increasingly small share of electricity generation.** The decline in coal is largely due to pressure from natural gas and solar generation.

Key insights pertaining to particular policy scenarios are given below.

- **S03a (Increased solar and battery requirements):** While this policy achieves a higher deployment of solar and battery deployment in 2030 compared to the base case, the base case ultimately achieves a higher penetration of solar and battery capacity by 2050.
- **S04c (Most Stringent Carbon Cap):** The medium and stringent carbon cap scenarios (S04b-c) were the only scenarios we tested where natural gas combined-cycle with carbon capture and sequestration (CCS) was deployed. In addition to CCS, onshore wind, solar, battery storage, and biomass gasification are required by 2050 to meet the cap. This scenario achieved the lowest emissions, as shown in Figure 3.
- **S05 (Clean Energy Standard):** Because our base case includes a significant expansion of solar PV, the results from the Clean Energy Standard are not appreciably different by 2050. We assume that existing nuclear can contribute to meeting the standard, which makes the policy less stringent. However, the clean energy standard leads to higher deployments of solar around 2035 – 2045 compared with the base case.
- **S06 (Extended Nuclear Generation):** The extension of nuclear lifetimes allows much the existing nuclear capacity to remain operational through 2050, which diminishes the need for new solar and gas turbine capacity. The extension of nuclear lifetimes helps to keep emissions signficantly lower than the base case, achieving 2050 emissions levels comparable to the intermediate CO_2 cap (S04b).
- **The ZEV scenarios (S07c):** Even with 10% adoption of ZEVs, there is not an appreciable effect on electricity demand or the projected electricity mix relative to the base case. As a result, the emissions trajectories for the ZEV scenarios are similar to the base case.

Figure 1. Electricity generation in terawatt-hours (TWh) through 2050 for the six key scenarios. Note that the Duke territory is modeled, and generation results are scaled to reflect the proportion of generation in North Carolina.

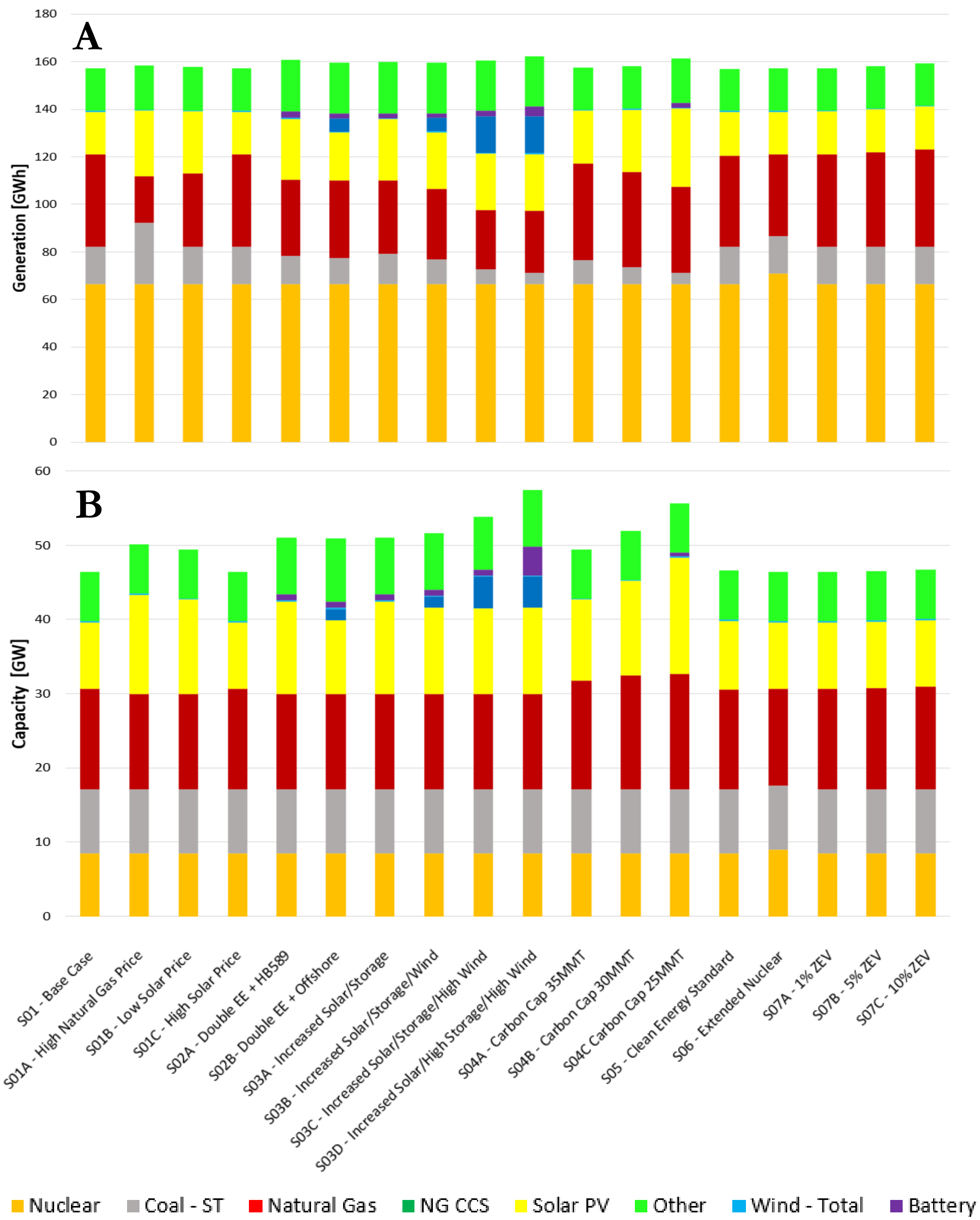

Figure 2. Electricity generation (Panel A) and installed generation capacity (Panel B) in 2030 across all 18 modeled scenarios. Note that the Duke territory is modeled, and generation results are scaled to reflect the proportion of generation in North Carolina.

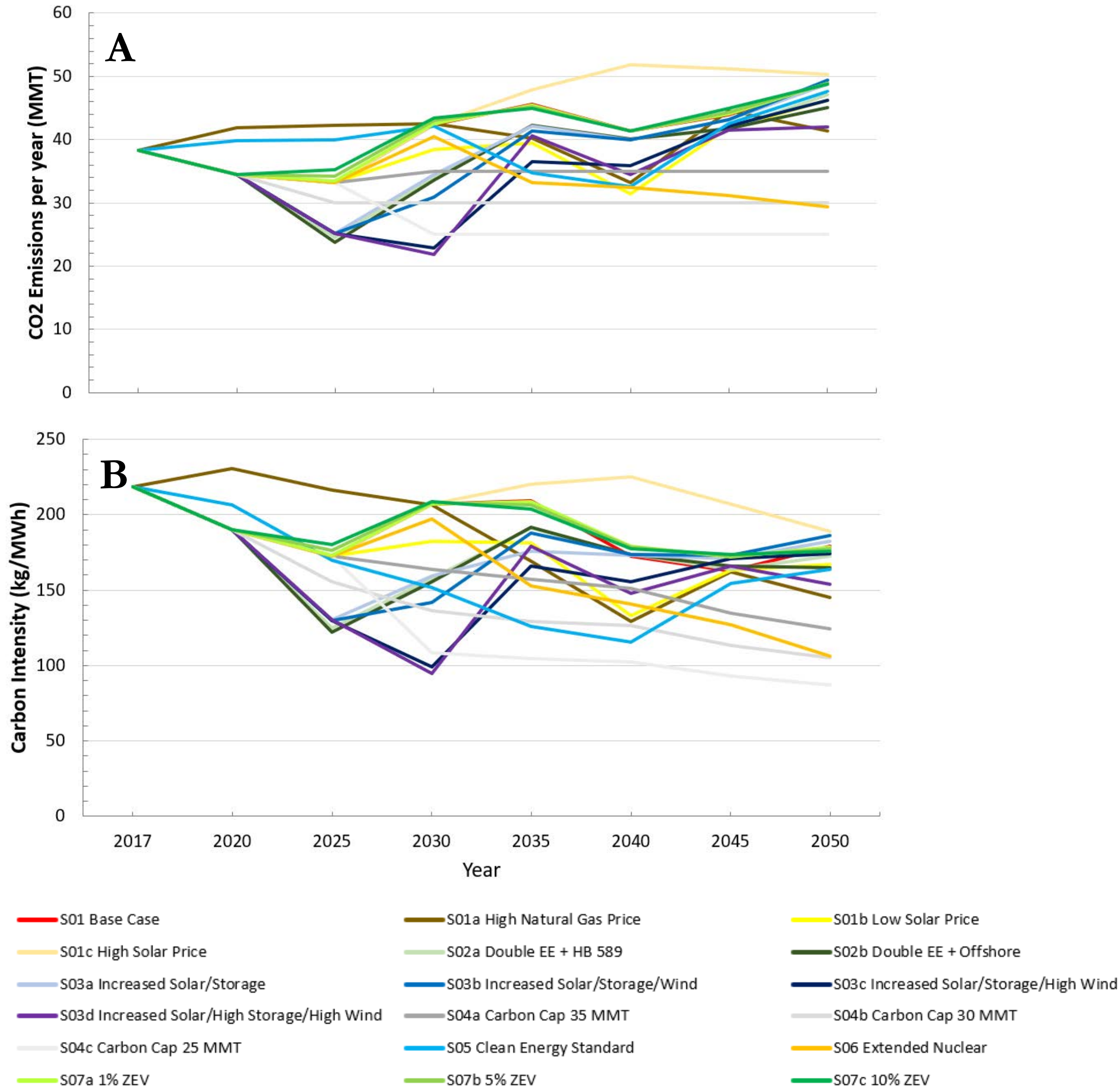

Figure 3. Annual CO_2 emissions (top panel) and CO_2 intensity (bottom panel). The high solar price scenario produces the highest cumulative emissions and highest emissions intensity, while the most stringent climate policy achieves the lowest cumulative emissions and lowest CO_2 intensity. Changes in a given trajectory largely correspond with the retirement of existing capacity and its replacement with new technology that has different emissions characteristics. Total emissions increase over time in several scenarios given increasing electricity demand, but the emissions intensity graph indicates that CO_2 emissions per unit electircity generation are generally decreasing with time. Note that the Duke territory is modeled, and generation results are scaled to reflect the proportion of generation in North Carolina.

Appendix

Figure A. Installed generation capacity in gigawatts (GW) through 2050 corresponding to the generation results presented in Figure 1. Note that the Duke territory is modeled, and generation results are scaled to reflect the proportion of generation in North Carolina.

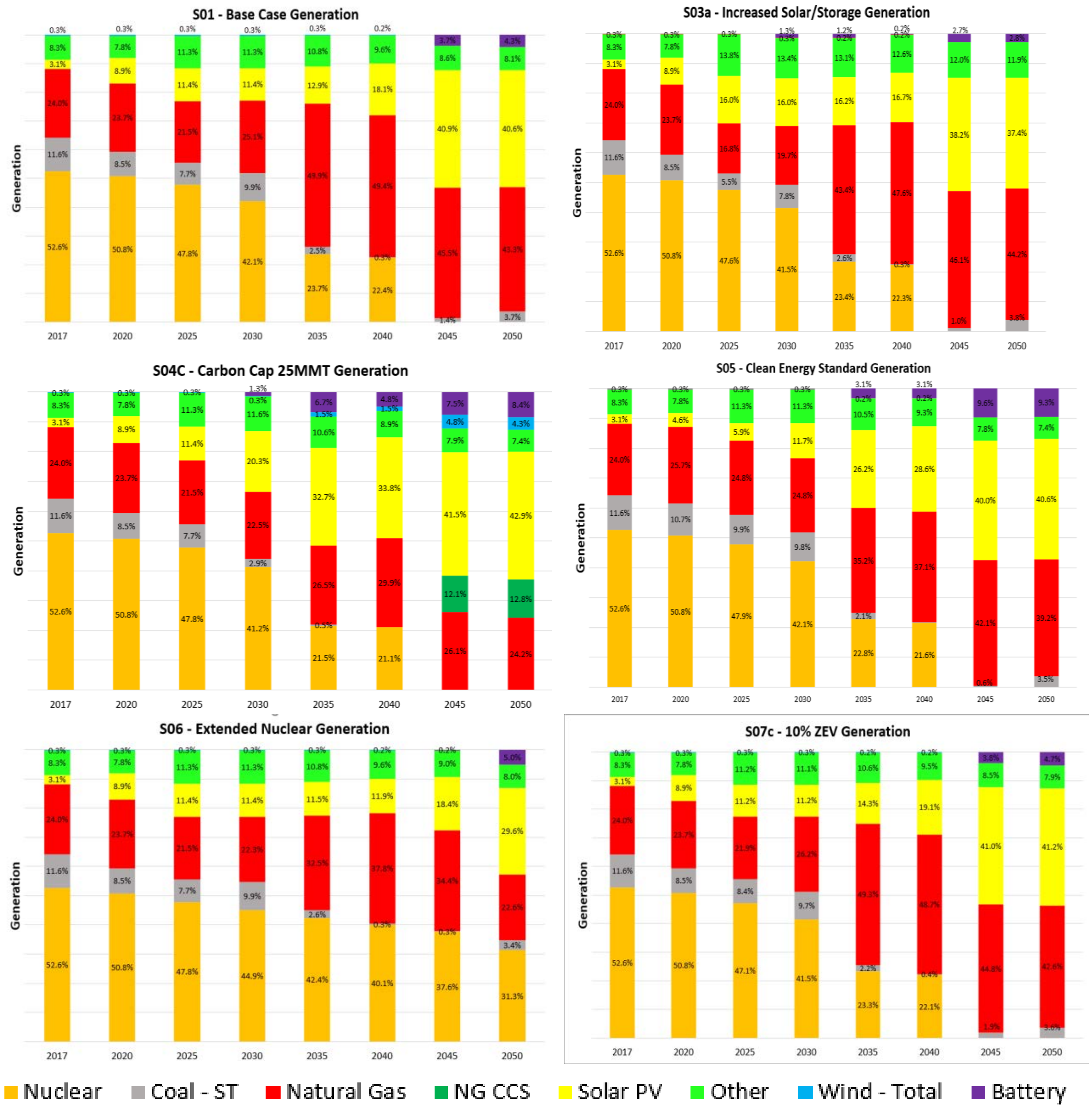

Figure B. Electricity generation mix through 2050 corresponding to the generation results presented in Figure 1. Bar labels indicate the percentage that each technology contributes to meeting total annual electricity demand.

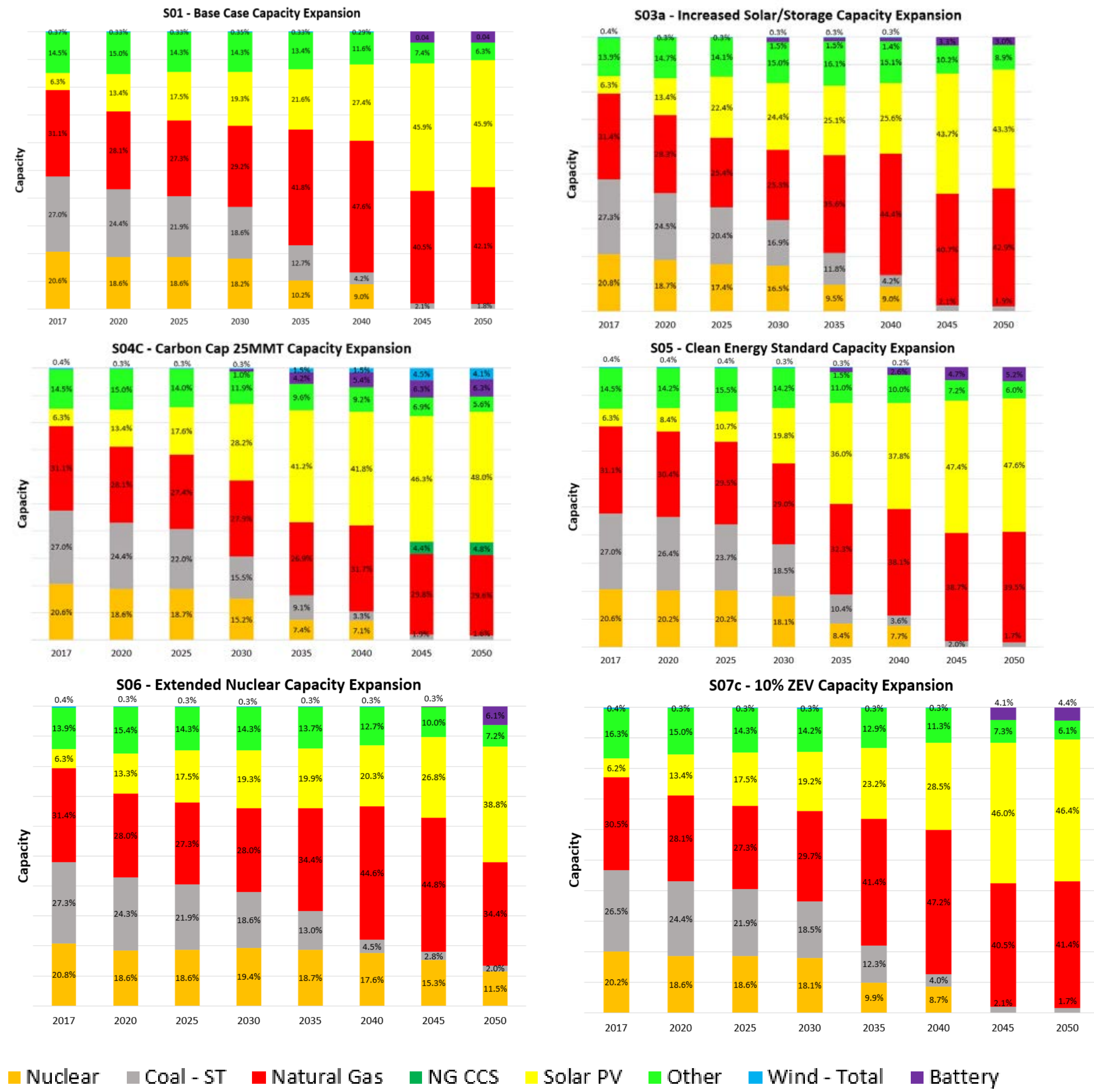

Figure C. Capacity mix through 2050 corresponding to the capacity results presented in Figure A. Bar labels indicate the percentage of total installed capacity associated with each technology.

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North Carolina's Power Future:
2019 Carbon & Clean Energy Policy Scenarios

Introductions

The Natural Resources Defense Council (NRDC) is a national not-for-profit organization with more than three million members and e-activists. In NRDC's North Carolina power analysis, we leveraged power sector modeling to understand the costs and benefits of various policy proposals for the state of North Carolina. Our analysis studied a variety of potential policies that could be used to comply with the climate goals of Executive Order 80. This analysis was performed by energy consultancy ICF, on behalf of NRDC, using their Integrated Planning Model (IPM®).

IPM is a detailed model of the electric power system routinely used by the electricity industry and regulators, including the U.S. Environmental Protection Agency and Regional Greenhouse Gas Initiative (RGGI), to assess the effects of environmental and energy-related regulations and policy. It integrates extensive information on power capacity and generation, technology performance, transmission, energy demand, electricity and fuel prices, policies, and other factors. IPM then determines the most cost-effective way to meet electricity needs - while complying with transmission, technological, and regulatory constraints - based on its detailed representation of the U.S. electricity system. It can build new power plants, retire existing plants, and/or ramp them up and down to meet demand reliably in the least-cost way. The model provides outputs at the state-level for all 48 continental states, including data on: generation, capacity, fuel prices and costs, fossil fuel consumption, O&M expenses, capital expenses, total system costs, wholesale and retail power prices, retail bills, and net exports.

Data Sources & Assumptions

All assumptions and scenarios were developed by NRDC, relying primarily on publicly available projections from various parts of the U.S. Department of Energy (DOE). A full table of assumptions is shown below. Additional detail on solar and storage cost assumptions is also provided.

All reference sources

A summary of assumptions with reference sources are listed below.

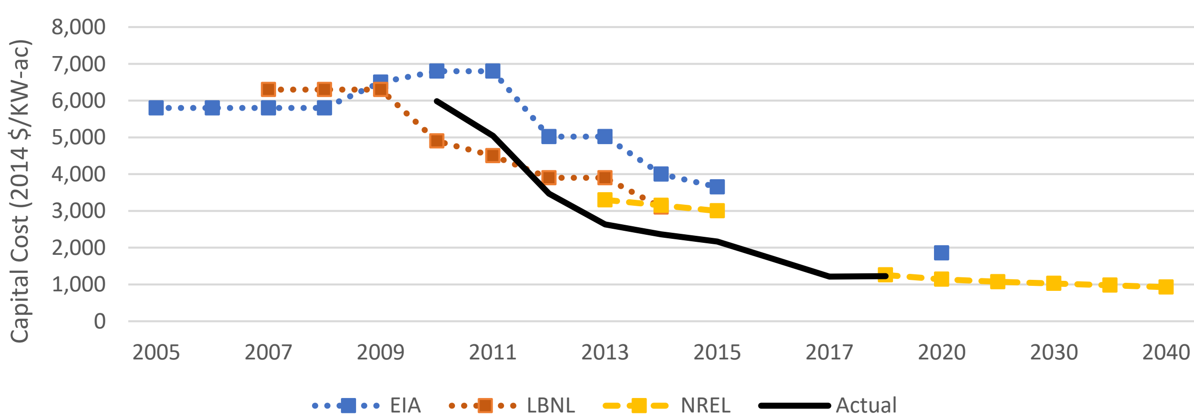
Assumption	2019 Reference Case Sources
IPM Version	IPM EPAv6
Electric Demand	AEO 2019
Capacity Build Costs - Conventional	AEO 2019
Capacity Build Costs - Renewable	NREL 2018 ATB. ITC and PTC[1] assumed per 2015 omnibus.
Capacity Build Costs - Storage	Storage allowed as an economic addition. Costs reflect NRDC assumed trajectory (mid-case projection between McKinsey, Lazard, and BNEF).
Coal Supply/Prices	EPA v6
Gas Supply/Prices	Fuel Supply Curves (AEO 2019), based on AEO 2019 reference case.

Firm capacity additions and retrofits	Latest market information (Q1 2019) and NRDC input.
Nuclear Retirements	Any nuclear reactors that reach age 40 can receive a subsequent license renewal and operate for 20 more years. Additional 20-year renewal is allowed at age 60 at cost of $4495/KW (max lifetime is 80 years).
Pollution Control Retrofit Costs	EPA v6
Biomass co-firing at coal facilities	EPA v6
Gas co-firing at coal facilities	EPA v6; NC units explicitly reviewed by ICF to reflect operational parameters.
Coal-to-gas conversions	EPA v6; NC units explicitly reviewed by ICF to reflect operational parameters.
Unit-level heat rates	EPA NEEDS[2] v6
(Regulatory) RPS State Policies	Reflects RPS[3] and state policies as of January 2019. All battery storage, offshore wind, and solar carve-outs are modeled. Includes HB589.
(Regulatory) Federal Rules Included	CAIR and CSAPR[4]; MATS (As finalized; allow HCl compliance via low-chlorine PRB coals); Regional Haze; Water Intake Structures; CCR[5]
(Regulatory) RGGI	New model rule; NJ and VA join at NRDC's recommended levels in 2020.
(Structure) Run years	(State reporting 2020 - 2050)
(Structure) EE Supply Curves	3 tier supply curve reflecting utility program costs (based on LBNL).
EE penetration	Based on NRDC analysis. EE only modeled in policy cases.
FOM and VOM	EPA v6

Notes: *1. Investment tax credit and production tax credit; 2. National Electric Energy Data System; 3. Renewable Portfolio Standard.; 4. Clean Air Interstate Rule and Cross-State Air Pollution Rule; 5. Coal Combustion Residuals.*

Solar costs

Figure 1. Actual vs. Projected Solar Costs



Source*: EIA, LBNL, NREL assumptions for 2005 – 2015 are drawn from EIA's March 2016 retrospective: "Wind and Solar Data and Projections from the U.S. Energy Information Administration: Past Performance and Ongoing Enhancements.". Actual data is drawn from NREL Solar Benchmarking reports. EIA and NREL data points for 2018 – 2040 are drawn from AEO 2019 and NREL ATB 2018, respectively.*

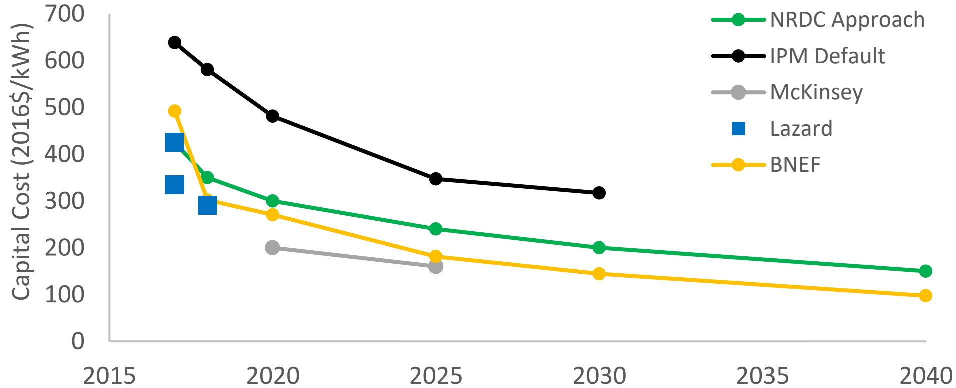
The model relies on the National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) for the cost and performance forecasts for new wind and solar projects[1]. For the costs and performance of new conventional and other alternative resources, the NRDC refers to the U.S.

[1] The use of NREL ATB for wind and solar costs, as an alternative to EIA AEO, is extremely common. The U.S. EPA, RGGI, and the State of New Jersey all use NREL ATB in their own IPM modeling analyses.

Energy Information Administration's (EIA) Annual Energy Outlook (AEO). Both NREL and EIA are part of the U.S. Department of Energy and all data is publicly available.

Battery storage costs

Figure 2. Battery Storage Costs



For the battery storage cost assumptions, NRDC merged estimates from Lazard's Levelized Cost of Storage 2.0 and 3.0, Bloomberg New Energy Finance (BNEF) Long-Term Battery Storage Forecast, and a 2016 study from McKinsey[2] to develop a mid-point cost trajectory, shown in green below[3].

Policy Scenarios

NRDC explored a variety of policy scenarios that covered a range of clean energy- and carbon-focused actions, such as strengthening the state's renewable portfolio standard (RPS), increasing energy efficiency investments (modeled as an energy efficiency resource standard or EERS), capping carbon emissions from power plants through the Regional Greenhouse Gas Initiative (RGGI), and combinations of these policies. (a complete description of each scenario can be found in Appendix A)

All of these policy cases were compared to a "business-as-usual" (BAU) without new clean energy or carbon policies implemented. In NRDC's modeling, there are two BAUs – an "optimized" and a "IRP-Like" scenario. The "optimized" BAU is designed to select the least-cost future energy portfolio for the state, based on the assumptions provided by NRDC and the transmission/system constraints of North Carolina; the "IRP" scenario is designed to more closely replicate the energy builds and mix in Duke Energy's "No CO2 Base Case" portfolios in their 2018 Integrated Resource Plans. (more detail on the builds assumed in this IRP case is found in Appendix A).

To assess the impact of each policy scenario, we studied whether the policy would (1) expand clean energy infrastructure, (2) lower power-related carbon emissions in the state, (3) limit power imports to favor in-state generation, and (4) have positive impacts on North Carolinians' long-term electricity bills, as compared to the "IRP-Like" BAU.

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[2] D'Aprile, Paolo, et al. "The New Economics of Energy Storage." *McKinsey & Company*, McKinsey & Company, Aug. 2016, www.mckinsey.com/business-functions/sustainability/our-insights/the-new-economics-of-energy-storage.

[3] IPM's default cost assumptions for battery storage were based Lazard's Levelized Cost of Storage 2.0 report. However, Version 3.0 had been released and seen significant downward revisions to its cost estimates (Version 4.0 has since come out and seen further declines). NRDC worked with ICF to adjust the batter costs to reflect The NRDC's new estimates attempt to be conservative in places (e.g. hitting $160/MWh 5 years after McKinsey anticipated), as this was a new structural addition to IPM modeling and there was little data to draw from.

Table 1. Scenarios Modeled

Model Scenarios		Metrics of Success (compared to IRP-Like BAU)			
Case Name	**Description**	**Expands clean energy**	**Lowers state emissions**	**Limits imports**	**Positive bill impacts (by 2030)**
"Optimized" BAU	Uses IPM v6. **Reflects 2019 assumptions** for demand, cost, & performance and energy policies as of Q1 2019.				
IRP-Like BAU	BAU 2019 + **New Builds to match DEC and DEP's "No Carbon" IRP Cases.**				
Clean Energy Policy	BAU 2019 + **Stronger RPS & EERS.** EERS set at 1.5% (0.25% ramp rate). RPS set at 30% by 2030 (linear trajectory from 12.5% in 2021 to 30% in 2030).	✓	✓	✓ ✓	✓
RGGI (w/ Leakage Measures)	BAU 2019 + **NC Joins RGGI in 2021.** NC's Mass cap is set at 44.5 million short tons (2020 BAU Emissions). Cap declines by 3%/yr through 2030. Flat thereafter. As a "leakage mitigation" measure, in-state generation must be greater than or equal to "optimized" BAU in all years.	✓	✓	✗	✓* *(0.0% impact)*
RGGI + Clean Policy	NC joins RGGI (same details as RGGI run) plus the stronger RPS & EERS (as detailed in the clean energy policy case).	✓ ✓	✓ ✓	✗	✓

Notes: ✓ *means "Yes, but not the best performer on the metric";* ✓✓ *means "Yes, and the best outcome on the metric";* ✗ *means "No, does not satisfy this metric"*

NRDC Preferred Scenario for North Carolina: RGGI + Clean Policy

Key Findings

1. **The state's power sector has an** immediate, cost-effective, and immense opportunity to cut carbon pollution.

In every scenario modeled—with or without new policy action—North Carolina sees a significant switch away from existing fossil-fired power plants to new renewable sources, especially solar power. As a result, emissions decline considerably in the near-term in all cases, including the BAU. Even without policy action, economic coal retirements result in the power sector reaching a 40 percent reduction in carbon emissions (from 2005 levels) by 2025. (see Figure 1, below). However, between 2025 and 2035, emissions outcomes diverge depending on the type of new generation capacity built in the scenarios:

- Emissions are highest in the IRP-Like BAU case due to the heavier build out of new natural gas (as proposed in the utilities' IRPs). This causes emissions to rise after 2025 and, thus, even though the power sector meets the 2025 target in 2025, emissions are projected to exceed this target within the following three years—and only grow past there.

- Emissions are lowest in the RGGI cases, where a cap is imposed on fossil and biomass power plant emissions. A carbon policy ensures that the state continues to see declining emissions post-2025 and incentivizes the state and its' utilities to invest in zero-carbon resources – like solar energy and battery storage – rather than gas resources to meet growing demand and replacement power needs.
- The clean energy case, where new policies support a stronger build out of clean resources without requiring any emissions caps, sees some additional emissions reduction beyond BAU, though emissions remain much higher than in the RGGI cases. The stronger RPS and EERS drives the greatest emissions reductions (compared to BAU) in the later years as RPS-driven solar builds and increased efficiency savings displace the need to run or build fossil fired plants to meet energy demand. However, without a policy that requires power plant operators to internalize the cost of their pollution, emissions still exceed the RGGI cases.

While the power sector is able to achieve reductions in line with the broader EO80 goal, it is important to remember that EO80 calls on the state to reduce all greenhouse gases economy-wide. The state's power sector has already cut carbon pollution by 37 percent as of 2017 (compared to 2005 levels), even as the rest of the state's economy has only reduced emissions by 12 percent. NRDC's modeling shows that the power sector still has a large, low-cost opportunity to slash emissions – beyond the 40 percent economy-wide target. Smart, cost-effective policies could drive much deeper pollution cuts from the power sector—and help lift the burden from other sectors of the state's economy, like agriculture and manufacturing, that can be costlier to decarbonize. If the state pursues both a carbon and clean energy policy package, the power sector could cost-effectively cut carbon pollution by 53 percent by 2025 and continue to cut emissions further into the future.

Figure 3. Annual Power-Related Carbon Emissions

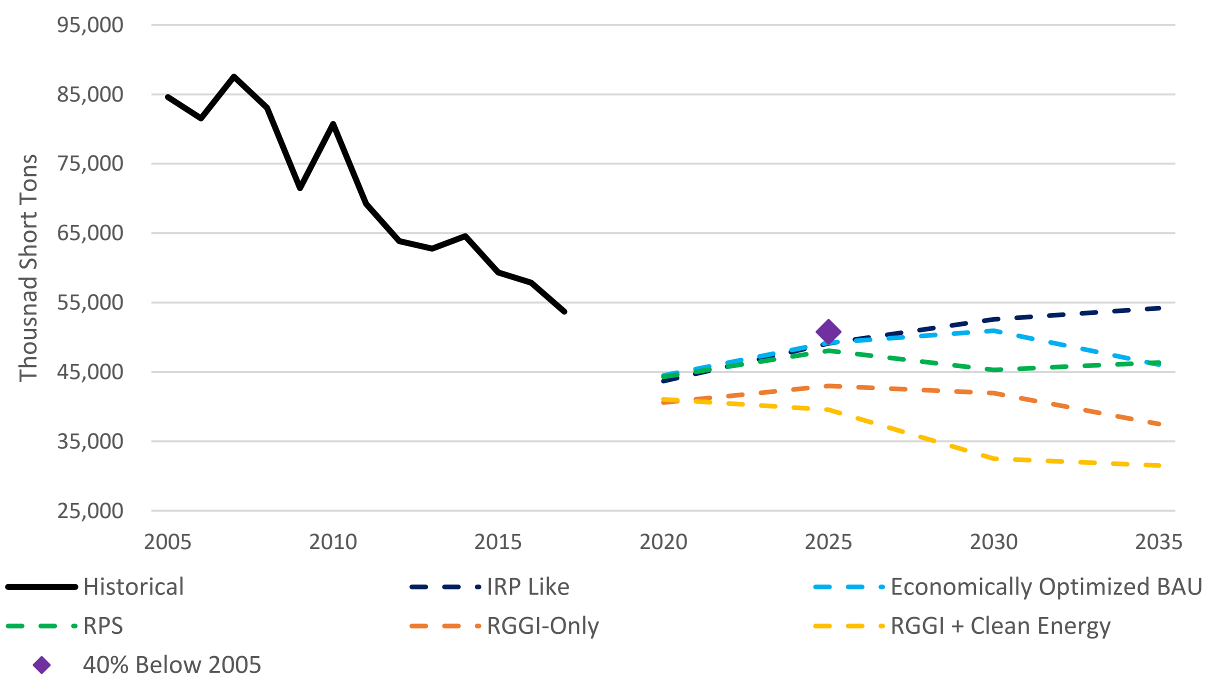


Table 1. Percent Reduction from 2005 Emissions Levels

Case	% Reduction in 2025	% Reduction in 2030
IRP-Like BAU	42%	38%
Optimized BAU	42%	40%
Clean Energy	43%	46%
RGGI-Only	49%	50%
RGGI + Clean Energy	53%	62%

2. Solar is a significant economic and environmental tool.

In every scenario modeled—with or without new policy action from the state—North Carolina sees a significant switch away from the dirtiest power plants to new clean, renewable sources. This transition away from fossil fuels to renewable (mostly solar) power is driven by economics, proving that clean energy can be an economic and environmental powerhouse for the state:

In all cases, there is strong growth (6 to 16 GW) in solar energy capacity. This is equal to a minimum 150% increase in the state's current solar capacity, with these projects represent between three and 10 billion in new capital investment over the next decade. To help integrate and balance this large increase in solar capacity and generation, the model economically builds up to 2 GW of battery storage, usually in the 2025 to 2030 timeframe as battery costs fall to levels that make them a low-cost option for integrating high levels of solar on the grid.

The cases with a stronger RPS see substantial increases in both solar and storage capacity well beyond the growth in the BAU and carbon policy (RGGI) only cases. This additional solar and storage growth is driven by the RPS targets, amounting to an extra 13 TWh of solar generation annually by 2030 (or enough to power over 1.2 million homes annually). The combined policy, involving both RGGI and strengthened clean energy policies, fuels the most solar and storage growth of any run.

Figure 4. In-State Capacity (GW)

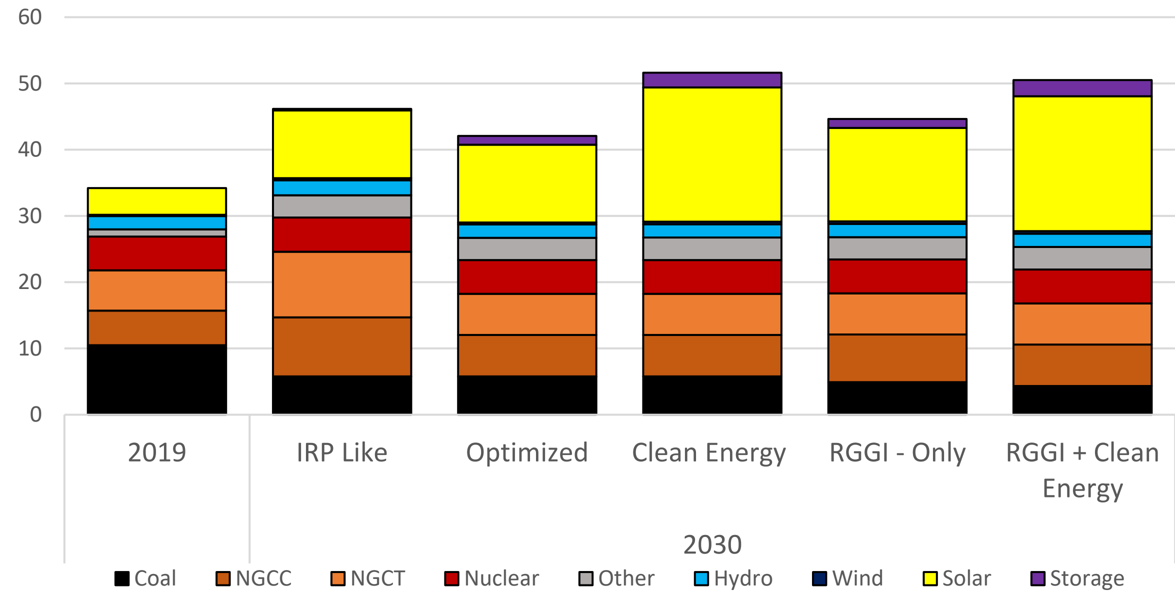
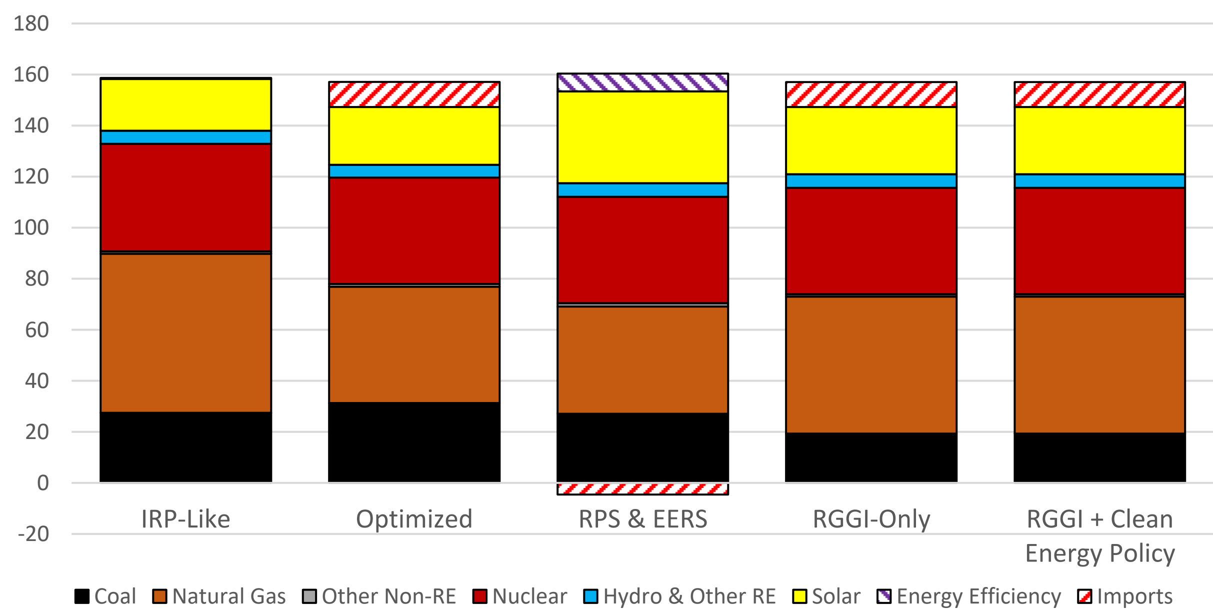


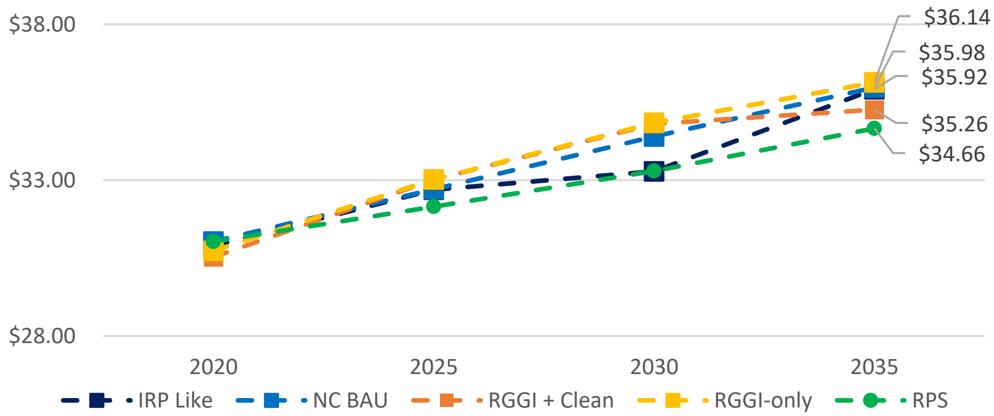
Figure 5. In-State Generation (TWh) in 2030



3. Clean energy and carbon policies keep energy affordable.

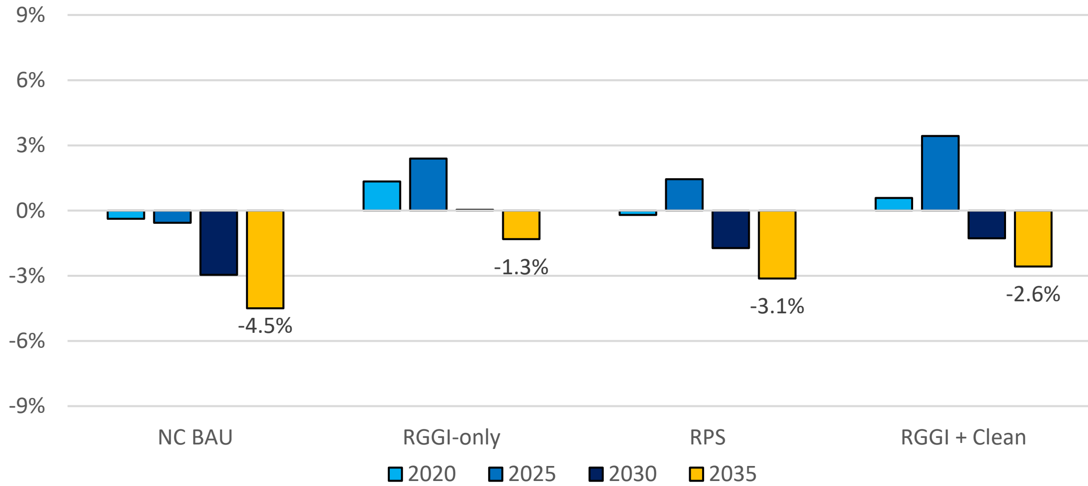
All scenarios see similar wholesale electricity prices, with prices increasing gradually over time as fuel costs, specifically natural gas prices are projected to rise. In 2035, the RGGI-only case sees the highest prices while the clean energy only case sees the lowest prices, though the difference is less than $1.50. After 2030, prices in the IRP-Like BAU case – due to its heavier reliance on natural gas - exceed those in scenarios that levy stronger clean energy standards.

Figure 6. Wholesale Energy Prices in NC (2012$/MWh)



While the policy scenarios that introduce new policies, like RGGI and RPS, involve a small upfront increase in electricity bills – as carbon allowances and renewable energy compliance costs are added to bills – these policies result in long-term bill reductions for the average household in North Carolina. By 2030, all policy scenarios see lower or similar bills to the IRP-Like BAU. By 2035, the IRP-like BAU is the most expensive option with all other cases seeing a 1-4 percent decrease in electricity bills by 2035.

Figure 2. Change in Bills (compared to IRP-Like Case)



References and Links

Sources:

- EPA National Electric Energy System (NEEDS) v6
- EPA's Documentation of IPM v6
- EIA Annual Energy Outlook (AEO) 2019
- NREL Annual Technology Baseline (ATB) 2018
- Lazard's Levelized Cost of Storage Analysis – Version 3.0

NRDC Materials:

- NRDC Blog: "North Carolina Poised to Slash Climate Pollution"

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Appendix A: *Description of BAU and Policy Cases*

IRP-Like BAU

This BAU scenario reflects assumptions for demand, cost, performance, existing state and federal policies, and plant announcements as of Q1 2019. It does not implement any new policies. It includes new builds to match the "No Carbon" base case of Duke Energy Carolinas' (DEC) and Duke Energy Progress' (DEP) integrated resource plan (IRP) (See Table 13-I in DEP's IRP and Table 12-I in DEC's IRP). The builds forced in this case are noted below. The model does still optimize the operation of existing builds (meaning it can retire aging coal plants, for example), but does not consider potential new economic builds in the 2019 – 2033 timeframe.

Annual Additions (MW)	2019	2020	2021	2022	2023	2024	2025
Solar (acts as cap on annual builds)	621	673	640	584	419	419	171
NGCC	-	560	-	-	-	-	1,338
NGCT	-	-	-	-	-	-	402
Energy Storage	12	16	28	34	34	36	36
CHP (gas)	-	22	44	-	-	-	-
Pumped Storage Uprate	-	-	65	65	65	65	-
Nuclear Uprate	30	6	4	6	-	6	-

Annual Additions (MW)	2026	2027	2028	2029	2030	2031	2032	2033	Total 2019 - 2033
Solar	146	145	145	143	142	12	12	12	4,284
NGCC	-	1,338	-	-	-	-	-	-	2,676
NGCT	-	-	460	2,760	-	460	920	1,380	6,382
Energy Storage	36	-	-	-	-	-	-	-	232
CHP (gas)	-	-	-	-	-	-	-	-	66
Pumped Storage Uprate	-	-	-	-	-	-	-	-	260
Nuclear Uprate	-	-	4	-	-	-	-	-	56

Optimized BAU

As above, this scenario reflects BAU assumptions for demand, cost, performance, existing state and federal policies, and plant announcements as of Q1 2019. It does not implement any new policies. In addition to optimizing the operation of existing builds, as in the IRP-Like scenario, it also considers potential new, economic builds.

Clean Energy Policy

This scenario implements a stronger Renewable Portfolio Standard (RPS) and Energy Efficiency Resource Standard (EERS). EERS ramps up to 1.5% at a rate of 0.25% per year. RPS is set to 30% by 2030, increasing linearly from the 12.5% level of 2021.

RGGI with Leakage Measures

Under this scenario, North Carolina joins RGGI in 2021. The state's emissions cap is first set to 44.5 million short tons (the 2020 BAU emissions level); this cap decreases by 3%/year through 2030, after which it remains constant. To prevent leakage, in-state generation must be greater than or equal to the optimized BAU levels for that year. In other words, net imports cannot exceed the optimized BAU levels for each year.

RGGI + Clean Energy Policy

This scenario combines the RGGI and Clean Energy Policy scenarios. North Carolina joins RGGI under the same conditions and leakage mitigation measures as the original RGGI scenario. The state also implements a stronger RPS and EERS at the same levels defined by the Clean Energy Policy scenario

RFF Modeling of Emissions and Technology Outcomes from Carbon Pricing and Renewable Policies in North Carolina

Introduction

Resources for the Future (RFF) is a 68-year-old research organization specializing in environmental and natural resource economics. RFF is independent and nonpartisan, and all of RFF's work is in the public domain. This project was funded by the Energy Foundation, the Merck Family Fund, and RFF's Energy and Climate Program, and was conducted as part of the RGGI Workshop Series under coordination of Laurie Burt of Laurie Burt LLC.

RFF applied its Haiku electricity market model, which has been used in two dozen peer-reviewed scholarly articles and in analysis to support state and federal agencies in examining approaches to environmental and economic regulation in the electricity sector. The model identifies state-level electricity market equilibria for the continental United States for three seasons and four time-blocks, solving for capacity investment and retirement through 2031 in an intertemporally consistent framework that assumes perfect foresight. System operation satisfies load while maintaining a minimum capacity reserve margin in all hours. Electricity demand is price responsive. We focus attention on results for 2026 to capture outcomes that could be expected in the current policy window and prior to the emergence of other trends such as technology change and national policy that might begin to depart from the model assumptions. The model has careful representation of relevant national and state-level electricity sector policies and can represent alternative distributions of emissions allowances under cap and trade and the effect of those distributions on overall outcomes.

Modeling

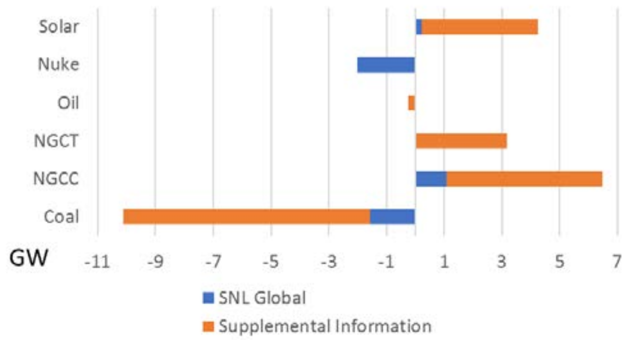
The supply side of the model begins with a bottom-up structure that aggregates capacity from an initial dataset of approximately 23,000 commercial power generators that were online in 2015. It then makes adjustments to capacity based on information drawn from SNL Global and from selected state energy documents, and the model proceeds to internally identify further investment and retirement outcomes necessary to achieve market equilibria at least cost. Power is tradable across states and regions up to transmission constraints that characterize the national power grid. The transmission constraints evolve according to assumptions in the 2017 Annual Energy Outlook (EIA 2017). The demand side of the model is a top-down system that characterizes changes in electricity consumption in response to changes in electricity prices. Electricity is priced at average cost in states that regulate power markets by cost of service and at marginal cost in states where wholesale power trades competitively.

Several characteristics of US power markets and approaches to policy design are accommodated in Haiku including:

- Cost-of-service retail electricity pricing where appropriate, including North Carolina
- Price-responsive electricity demand
- Internally consistent representation of dynamic output-based emissions allowance allocation under an emissions cap to provide incentives for generation with specific technologies
- Endogenous investments in demand-side energy efficiency

- Endogenous and internally consistent representation of features of the RGGI program design, including the cost containment reserve, the emissions containment reserve, and the price floor

Baseline assumptions for North Carolina have evolved as coal units have retired and new natural gas and solar units have come into service. Figure 1 illustrates assumed changes in capacity expected after 2018 as identified by SNL Global and from supplemental information gathered from integrated resource plans and other sources. This baseline serves as a point of departure for changes in capacity identified in various modeled scenarios.



Note: NGCT = Natural Gas Combustion Turbine; NGCC = Natural Gas Combined Cycle

Figure 1. Assumed baseline capacity additions & retirements in North Carolina after 2018

The changing capacity, relative fuel prices, and other factors have also changed the expected utilization of capacity. Figure 2 illustrates a "prior baseline" based on assumptions built on information from 2015, and the updated baseline generation and emissions outcomes, both for the year 2026. This comparison illustrates the changes that are already happening in the state. Carbon emissions are forecast as 46.4 million tons; emissions from sources that are greater than 25 MW and that would be covered under RGGI-style cap-and-trade scenarios are 44.1 million tons.

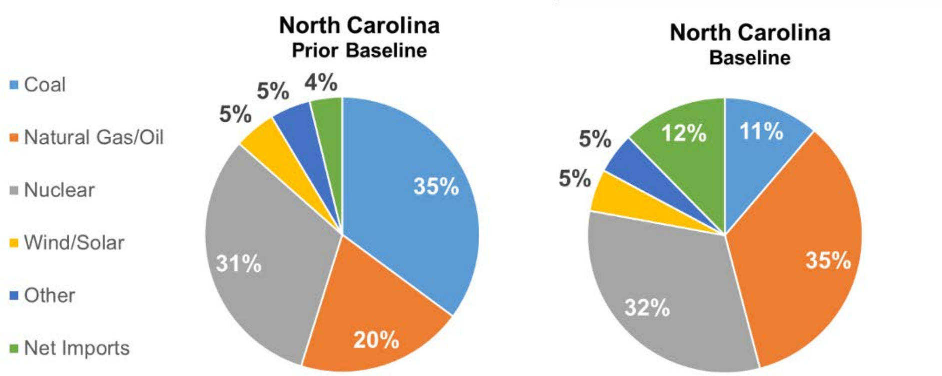


Figure 2. Baseline generation mix for North Carolina in 2026

RFF analyzed eight policy scenarios including one that would promote in-state development of wind and solar, and seven others that examined the introduction of carbon pricing. The carbon pricing scenarios were differentiated along two dimensions. One dimension is how the tradable emissions allowances would be initially distributed. We examined:

a) No allowance allocation (NoAA), under which allowances were auctioned and revenues directed to the general fund.
b) Allocation to producers using output-based allocation (OBA), under which allowances were allocated to all generators except coal and existing renewables based on their share of

generation. This approach provides an incentive for these sources to produce more power to earn valuable emissions allowances.

c) Allocation to consumers (EE_LDC) to promote energy efficiency and to reduce the change in electricity prices.

The second dimension for the policy scenarios is whether the carbon pricing policy in North Carolina was linked with the existing Regional Greenhouse Gas Initiative RGGI in eleven other states (we assumed Virginia was participating as part of RGGI). Finally, in one scenario we combined the technology policy with carbon pricing.

Results and Discussion

We identify five key findings from this analysis.

1. Emissions reductions can be achieved at very low cost

Figure 3 illustrates that baseline emissions are already expected to fall from 2020 levels going forward. Our projected baseline is nearly on course to achieve the emissions cap through 2026 without a carbon price. Nonetheless, the cap-and-trade policy options achieve even greater emissions reductions, as we explain below.

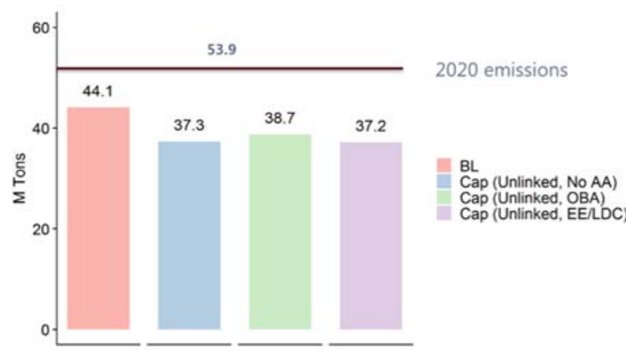


Figure 3. Emissions in 2026 under cap-and-trade scenarios

The cap-and-trade scenarios achieve cumulative reductions by 2030 of about 150 million tons measured from 2020 emissions levels. The falling baseline emissions projection contributes much of emissions reductions compared to 2020 emissions levels; nonetheless, measured against the improving baseline, cap and trade achieves additional cumulative reductions of 81 million tons.

2. Low allowance prices accelerate emission reductions under the RGGI model.

We imagine a design for cap and trade borrowed from RGGI with cost control features including an “emissions containment reserve” and a “price floor” as illustrated in Figure 4. These features prescribe minimal accepted prices for some portion of the emissions cap. Ten percent of the allowances will not enter the market at auction prices below the emissions containment reserve price, and no allowances enter at prices below the price floor. These important cost management features translate low allowance prices into significant additional emissions reductions.

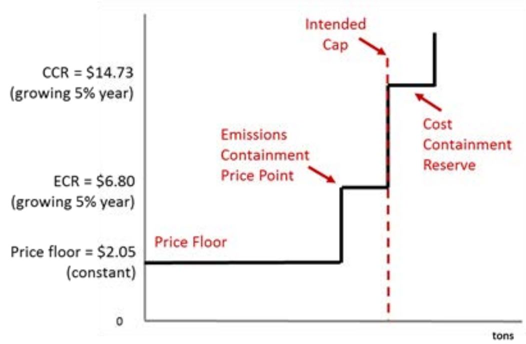


Figure 4. The allowance supply schedule (2026 prices/2015 real$)

Low prices yield an additional 4% annual emissions reduction by 2030, and 10.4% additional cumulative reductions over the decade compared to2020 levels, beyond what is required by the cap. The additional reductions are achieved because the cost management features reduce the number of allowances that enter the market when prices are below the emissions containment reserve price trigger or the price floor. The cost management features are implemented in an auction, but we note these features can be implemented even when allowances are given away for free by use of a consignment auction, with auction proceeds returned to the original holders of allowances.

3. Renewable energy policy achieves emissions reductions at greater cost than cap and trade but also creates important clean energy infrastructure for the future.

The renewable energy policy we model is described as a Renewable Technology Standard (RTS) that requires in-state wind and solar generation to grow by 1% of electricity consumption per year. By 2026 this policy in isolation results in emissions of 39.7 million tons (MT), a reduction from 2020 levels and from the baseline, but greater than the emissions outcome achieved by cap and trade (approximately 38 MT, varying across scenarios). The RTS also requires more upfront capital investments than cap and trade.

However, the renewable policy succeeds in approximately doubling the amount of renewable capacity and generation compared to cap and trade, thereby providing important new infrastructure and valuable experience with renewables integration that puts the state in a better position for the future.

An option used in many states is a combination of policies to achieve cost effective emissions reductions in the near term and to put in place a renewable energy infrastructure for the future. The combination of policies leads to the lowest emissions as illustrated in Figure 5.

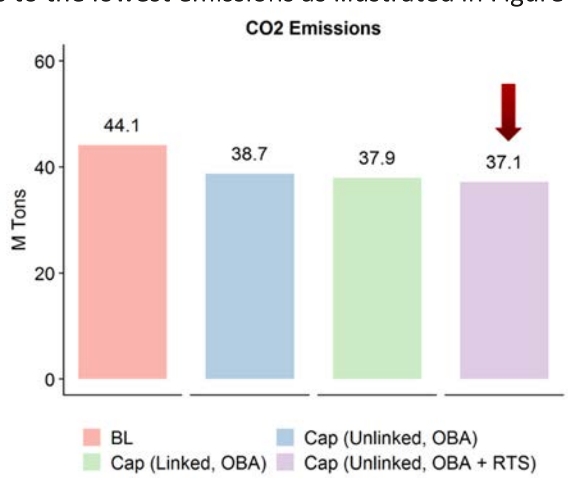


Figure 5. Emissions in 2026

4. The "trade-ready program design" we model could link seamlessly with the Regional Greenhouse Gas Initiative.

Adopting the RGGI program design makes linking straight forward. Allowance prices in North Carolina are similar to prices expected in the eleven state RGGI region (including VA and NJ) so linking results in little shift of emissions, and in fact slightly reduces total emissions in the combined region, as illustrated by Figure 6 for the OBA allocation scenario. Linking provides greater resiliency for the program and stability for allowance prices in face of uncertain weather, fuel prices, etc., while preserving state autonomy and programs.

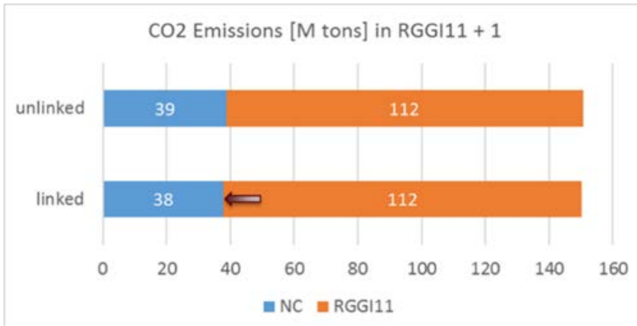


Figure 6. CO_2 emissions fall when the programs are linked

5. Emissions in North Carolina (and across the country) are falling over time.

The electricity sector in North Carolina is transitioning toward cleaner generation. Capacity factors at Duke Energy's coal units have fallen by half over the past decade. Drawing on forecasts by EIA, EPA and utility Integrated Resource Plans, we construct a baseline projection for next decade. Figure 7 illustrates our expectation that by 2026 natural gas and nuclear would each represent about one-third of electricity generation in the state in the absence of clean energy policy, with coal representing only 11 percent. A cap ensures further emissions reductions are realized and provides a strong signal for investors and innovators seeking to expand clean energy.

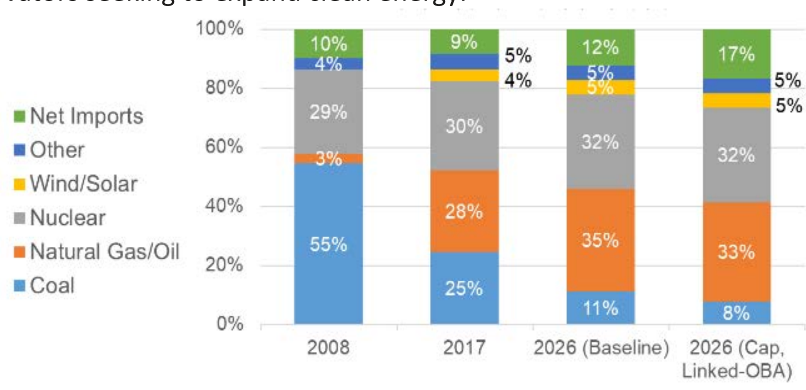


Figure 7. Historic and projected generation in North Carolina (Historic source: EIA)

References

EIA. 2017. *Annual Energy Outlook*. Energy Information Administration.

The full report, State Policy Options to Price Carbon from Electricity, is available at https://www.rff.org/publications/reports/state-policy-options-price-carbon-electricity/

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