North Carolina

Clean Energy Plan

Transitioning to a 21st Century Electricity System

Supporting Document

PART 5

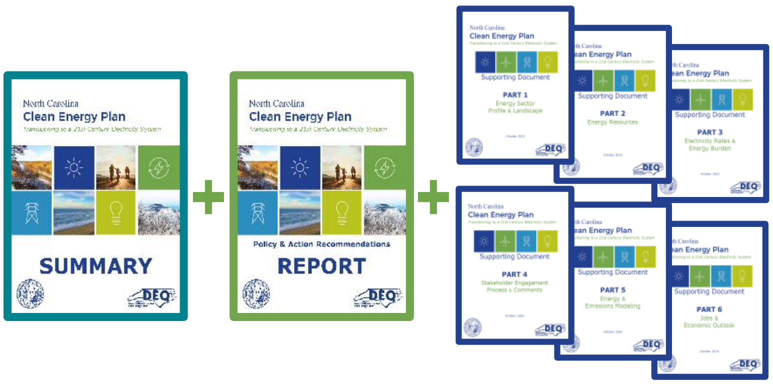
Energy & Emissions Modeling

October 2019

NORTH CAROLINA
Department of Environmental Quality
State Energy Office

Preface

The Clean Energy Plan was written by the Department of Environmental Quality as directed by [Executive Order No. 80](https://files.nc.gov/ncdeq/climate-change/EO80--NC-s-Commitment-to-Address-Climate-Change---Transition-to-a-Clean-Energy-Economy.pdf).[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 voluntarily conducted by external groups.

[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

In EO80 Governor Cooper directed DEQ to develop a N.C. Clean Energy Plan (CEP) that advances the use of clean energy resources and reduces power sector emissions. The CEP process was designed to identify programs, policies and actions North Carolina could take to achieve its goals for clean energy and emissions reductions. Electricity sector modeling analysis provides useful information about trends in the electricity sector and the potential impacts of policy actions. This supporting document summarizes the modeling analyses of four organizations.

Modeling analyses seek to answer key questions for evaluating potential policy actions. Given assumptions about the future (e.g., costs of new technology, fuel prices, electricity demand), models first establish a reference or business-as-usual case that projects how the electricity sector would evolve in the absence of new policy. Will carbon emissions increase or decrease and by how much? What power plants are likely to serve electricity demand in the future and will new generation sources be required? Are existing power plants economical to retire? What share of the generation mix will be provided by each type of generation? What are the expected impacts on electricity prices? Reference cases are important because they provide a point of comparison for policy scenarios that project the impacts of new policy actions.

While a reference case gives policy makers and stakeholders a sense of the future electricity sector assuming least-cost decision-making, policy cases seek to identify the benefits and costs of new programs, policies or actions. The modeling efforts detailed in this Part 5 examined three types of policy actions, alone or in combination:

1. Clean technology standard, renewable energy standard, or energy efficiency resource standard aimed at increasing the amount of electricity purchased and produced by specified technologies or increasing the amount of energy savings;
2. Carbon trading program limited to North Carolina or linked to other similar state programs that make up the multistate Regional Greenhouse Gas Initiative (RGGI); and
3. A policy that requires coal retirements and requires replacement capacity to be met with renewables.

Each of the organizations completed at least one reference case, and at least one policy case to help understand the potential benefits and costs of specific policy actions. Each of these individual efforts are described in greater detail below. While the models and modeled inputs vary across the different analyses, modelers made the following overarching observations:

- To achieve significant reductions beyond business as usual, the modeling suggests additional action will be needed. The modeling indicates that without additional policy action, North Carolina’s carbon emissions are likely to increase or decrease slightly by 2030, depending on the analysis.

- Emissions reductions can be achieved at low cost through a state trading program, especially when the program is linked to those in other states.

- Market-based carbon policies combined with policies to increase energy efficiency and renewable energy can further reduce carbon emissions and increase deployment of clean energy resources in North Carolina.
- The particular design of new policies is important and has noticeable impacts on potential emissions reductions, wholesale and retail electricity cost impacts, capacity needs, generation mix, increase in clean energy resources, implementation costs, electricity imports, and economic benefits for the State.
- Additional modeling analysis would help identify the particular policy designs of a market-based carbon reduction program and complementary policies--such as updating North Carolina's REPS, establishing a clean energy standard, or passing an energy efficiency resource standard--to maximize benefits and minimize costs. Policy design includes elements such as level of stringency, parties covered by the policy, compliance timeline, mitigation of imported fossil generation, and strategies for investing any revenue generated.

These overarching observations inform CEP recommendation A-1, under which DEQ will enlist assistance from academic institutions to deliver a report to the Governor by December 31, 2020, that recommends carbon reduction policies and the specific design of those policies to best advance core values—including a significant and timely decline in greenhouse gas emissions, affordable electricity rates, expanded clean energy resources, compliance flexibility, equity, and grid reliability. The report will evaluate policy designs for the following: (1) accelerated coal retirements, (2) a market-based carbon reduction program, (3) clean energy policies such as an updated REPS, an EERS and clean energy standard, and a (4) a combination of these policy options.

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1. Introduction

Executive Order 80 calls for a CEP that identifies potential actions to achieve the state's clean energy and emissions goals. To inform the CEP, four organizations voluntarily conducted modeling analyses of policy actions under consideration by stakeholders in North Carolina. The modeling identifies potential benefits and costs of a number of different policy approaches. DEQ carried out additional analysis of its own. This Part 5 summarizes those analytical efforts.

1.1 The Purpose of Modeling

Sophisticated computer models are used by industry and government to better understand how the electricity sector is likely to evolve, and how the system is likely to react to certain events or actions. Policy makers use electricity sector models to understand the potential impacts of proposed policies compared to business as usual, and to select among different policy designs. Models are not meant to definitively predict the future. Rather, they provide a sense of the directional impact of a policy option given the energy resources, constraints, and complexity of the electricity system.

The modeling analysis submitted by the four organizations were conducted independently and voluntarily. The assumptions used in the analyses were chosen by the organizations themselves, and the parameters of the policy options modeled were not directed by North Carolina state officials. They cover a limited number of policy design variations and do not explore a wide range of sensitivities (e.g., natural gas prices, load growth, costs of renewables and battery storage, and allowance prices), two elements typically considered by policy makers when making conclusive decisions about policy design. As such, these modeling analyses are informative but may not include the same assumptions and/or policy designs that modeling done for regulatory purposes might contain.

1.1.1 The Modelers and their Models

This section describes the modelers, the models used, and how the models work, before summaries of modeling reference cases and results are presented in subsequent sections. Each of the modeling organizations provided a written description of their analyses, which is included at the end of this summary section.

Resources for the Future

Resources for the Future (RFF) is a 68-year-old research organization in Washington, DC, that specializes in environmental and natural resource economics. RFF is an independent and nonpartisan 501(c)(3) organization, and all of RFF's work is in the public domain. RFF's mission is to improve environmental, energy, and natural resource decisions through impartial economic research and policy engagement.

RFF used its Haiku model to carry out its modeling analysis. The Haiku electricity market model 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 dynamic capacity investment and retirement through 2031 in an intertemporally consistent framework. System operation satisfies load while maintaining a minimum capacity reserve margin in all hours. Electricity demand is price responsive. Although RFF modeled through 2031 for the CEP, it places special focus on 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 represents relevant national and state-level electricity sector policies and can represent a variety of alternatives.

Georgetown Climate Center

Georgetown Climate Center (GCC) is a nonpartisan center of Georgetown University Law Center that serves as an objective resource to states working to cut carbon pollution through law and policy. GCC is currently serving as a resource to the Commonwealth of Virginia in its effort to implement a market-based carbon reduction program that is linked to RGGI.

GCC used the energy consultancy ICF to conduct its analyses with the Integrated Planning Model (IPM). IPM is a sophisticated and detailed model of the electric power system used by utilities, regulators (including the U.S. Environmental Protection Agency, all of the RGGI states and Virginia) to assess the impacts of energy-related policies. IPM 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 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.

The Natural Resources Defense Council

The Natural Resources Defense Council (NRDC) is a national not-for-profit organization with more than three million members and e-activists that advocate for the adoption of clean energy policies. NRDC also used ICF and the IPM model to conduct its analysis.

North Carolina Department of Environmental Quality

DEQ is the environmental regulatory agency for the state. DEQ used two projections as references: the projection of emissions developed for its 2019 Greenhouse Gas Inventory compiled using Duke Energy's 2017 forecast provided to the NC Division of Air Quality for air quality planning purposes, and a newer reference projection compiled using the Eastern Regional Technical Advisory Committee's (ERTAC's) EGU Tool. To analyze the potential effects of retiring all coal plants and replacing that generation with energy efficiency and renewables, DEQ used the ERTAC EGU Tool for its analysis. The ERTAC EGU Tool was developed by a group of states for use in air quality planning. ERTAC's EGU Tool allows state air regulators to project the emissions from fossil-fuel-fired electric generating units based primarily on Annual Energy Outlook (AEO) 2019. Those estimates are then used by states in compiling state implementation plans under the federal Clean Air Act. ERTAC's EGU Tool is an hourly, unit level projection based on AEO fuel use growth factors and forecasts generation from the existing fleet and projects the need for new units while meeting constraints for reserve margin, excess generation and other factors. The tool does not optimize the electricity system's response to a policy action using a least-cost method. Instead, it demonstrates the impact of a policy on fossil fuel units based on projected fuel use and costs for the electricity sector.

North Carolina State University

Researchers from NC State University (NCSU) used the model Tools for Energy Modeling Optimization and Analysis (Temoa). Temoa is an open source, bottom-up energy system optimization model developed at NCSU. The model 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.

The input dataset developed for NCSU's modeling analysis covers the Duke Energy Progress and Duke Energy Carolina service territories, which cover most of North Carolina and a large section of South Carolina. Modeling both territories, rather than just the North Carolina areas, better reflects system-level operation.

1.2 Future Scenarios Modeled

1.2.1 Reference Cases.

Each of the modeling analyses started with a reference case or business-as-usual scenario that used the model to project a future without new policies or actions.

1.2.2 Carbon Trading Programs.

Three organizations modeled one or more carbon trading program designs. Under a trading program, the state sets on overall limit on emissions from power plants and issues "allowances" – one allowance for each ton of carbon dioxide allowed under the cap. Power plants must measure, monitor and report their emissions. To remain in compliance, they must turn in one allowance for every ton of CO2 emitted during a specified period of time. Allowances are tradable among covered emission sources (e.g., power plants). Because the total number of allowances is limited, total emissions will not exceed the overall emission limit, so long as all generators comply with their obligation to cover emissions with allowances.

a) Multistate Carbon Trading Program. In some of the modeling analyses, the modelers chose to model a North Carolina carbon trading program linked to the existing multistate RGGI program. This is because larger markets are more likely to meet overall emission limits at a lower cost than smaller markets.
b) NC-Only Carbon Trading Program. Some modelers ran a policy scenario with a North Carolina Trading Program that is separate and unconnected to existing state trading programs.

1.2.3 Renewable Portfolio Standard (RPS).

An RPS is a policy that requires utilities to supply a certain percentage of renewable electricity to customers.

1.2.4 Clean Energy Standard (CES).

A CES is a policy that requires utilities to supply a certain amount of clean energy to customers. In general, "clean energy" is more broadly defined than renewables and can include power from nuclear, cleaner fossil fuel plants, such as those with cleaner emission rates or with carbon capture and storage.

1.2.5 Energy Efficiency Resource Standard (EERS).

An EERS requires utilities to meet a prescribed energy savings rate each year, driving investments in energy efficiency measures.

1.2.6 A Requirement to Retire All Coal and Replace it with Renewables.

Another approach to reducing emissions is to compel the retirement of all coal plants and require that all replacement generation be zero-emission renewable electricity. This requirement was analyzed by DEQ using the ERTAC EGU Tool.

2. CEP Modeling: Reference Cases

2.1 Reference Cases in General.

A reference case projects the future of the electricity system without new actions or policies. It attempts to answer the question, "What will happen without new policies?" Projecting the electricity system in the future is not an exact science, but relies on a set of assumptions about the conditions likely to be present in the future. Key assumptions include future natural gas prices, electricity demand, and the cost of renewable generating facilities. For example, if one assumes that natural gas prices will remain low in the future, then a model that solves for the least-cost future will be more likely to include natural gas generation if it is the lowest cost option. Thus it is important to understand the assumptions that go into a reference case in order to understand the results.

2.2 The Reference Cases for CEP Modeling.

While some general observations hold true across all of the reference case scenarios of the four organizations, the use of different models and different assumptions means the reference case results vary. Each organization's reference case is described below, including key assumptions and high-level observations from the reference case results.

2.2.1 Resources for the Future

Reference Case: RFF modeled North Carolina as a regulated electricity market. New Jersey and Virginia are modeled as linking to RGGI in 2020, and it models states in the RGGI region as having competitive electricity markets except for Virginia, which is represented as a regulated electricity market. Haiku is calibrated to the anticipated electricity demand growth, fuel prices (including natural gas), new generating capacity costs and performance and regional generation of the Electricity Market Module of the National Energy Modeling System as used for the 2017 Annual Energy Outlook (EIA 2017). Baseline assumptions for North Carolina have evolved since the release of EIA's 2017 Annual Energy Outlook as coal units have retired and new natural gas and solar units have come into service. Changes in capacity expected after 2018 were identified from S&P Global and from supplemental information gathered from integrated resource plans and other sources.

Calibration of the Haiku model captures virtually all technology and emissions policies that are important in the power sector, including federal renewables subsidies, state renewable portfolio standards, Title IV of the Clean Air Act, the Cross-State Air Pollution Rule (CSAPR), Mercury and Air Toxics Standards (MATS), RGGI, and California's Global Warming Solutions Act of 2006 (AB32), as well as forecasts for fuel and technology cost projections and electricity demand. The regional forecasts for electricity generation from EIA are downscaled to the state level and compared with recent state-level forecasts used by the Environmental Protection Agency (2018) and information collected from integrated resource plans and other forecasts.

RFF notes three areas of uncertainty with respect to its reference case. First, because natural gas prices are very important to modeled outcomes, natural gas prices that are higher than those assumed would lead to different results. Second, electricity demand is forecast to remain relatively flat in the modeled time horizon, consistent with recent trends. But if electric vehicles are rapidly adopted in the 2020s, this could lead to increases in demand not modeled. Third, federal policy on energy and environment is an area of future uncertainty that would affect any business-as-usual projections. These uncertainties are present generally in all of the modeling analyses summarized in this Part 5.

RFF's High-level Observations from its Reference Case.

a) Carbon Emissions. In RFF's reference case total carbon emissions in the baseline from the power sector are forecast as 46.4 million tons in 2026, and emissions from sources that would be covered under the cap-and-trade scenarios are 44.1 million tons. By 2031, total emissions are expected to fall to 40.4 million tons. Even given these reductions, North Carolina is not expected to achieve a 70% reduction in electricity emissions from 2005 levels without new action.
b) Changes in Generation Mix. RFF expects natural gas generation to grow from 28% of total generation in 2017 to 35% in 2026. At the same time, coal generation will decrease to about 11% of total generation in 2026 compared to 25% in 2017. Renewables will make up 5% of generation in 2026 compared to 4% in 2017.

2.2.2 Georgetown

Reference Case: GCC used the same model and the same assumptions used by the 9 RGGI states to model revisions to the RGGI program. RGGI compiled its modeling assumptions in a stakeholder process that sought input from industry and environmental organizations and is informed by more than 10 years of RGGI state experience with IPM modeling of trading programs. The analysis also included NC-specific factors such as electricity demand growth, planned new power generating plants, and retirements of existing power plants. The table below sets out the key assumptions for the analysis.

Table 1: GCC Key Assumptions for Analysis

Assumption	ICF Analysis for GCC
Natural Gas Price Forecast	EIA's Annual Energy Outlook for 2018, taking the midpoint between the reference and high resource forecasts
Electricity Demand Forecast	PJM, NYISO & ISONE demand forecasts, as adjusted by the RGGI states to incorporate state energy efficiency programs. For North Carolina, the AEO 2018 demand forecast was used, because North Carolina utilities do not participate in a regional transmission organization (RTO).
Renewables Costs	U.S. Environmental Protection Agency v6 Renewables Capital Cos for this case. The IRP
Treatments of Firm Builds and Firm Retirements	In each of the RGGI states, states started with RTO queues and made final decisions on firm builds and retirements. For North Carolina, Duke Energy's IRP was used.

For the business as usual case, it was assumed that both Virginia and New Jersey would be part of RGGI. Energy policies already in place were included in the business as usual scenario.

GCC's High-level Observations from its Reference Case

a) Carbon Emissions. In GCC's 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. This suggests that existing market conditions and policies are not enough to significantly reduce carbon emissions from the electricity sector in the state. New actions would be necessary to achieve reductions.

b) Solar Additions. The model projects that North Carolina will meet and significantly exceed the 2.66 GW solar procurement requirements in House Bill 589, adding 5.7 GW of new solar capacity by 2030 on an economic basis.

c) Natural Gas Additions. Approximately 1.9 GW of new natural gas combined cycle is projected through 2030, in addition to the 1.5 GW already planned by Duke in its 2019 NC IRPs.

2.2.3 NRDC

Reference Case: NRDC developed a set of model assumptions for its modeling analysis and described the sources of those assumptions in the table below.

Table 2: NRDC Key Assumptions for Analysis

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

NRDC's High-level Observations from its Reference Cases.

NRDC developed two reference cases: the "Optimized BAU case" and the "IRP-like reference case." In the Optimized BAU case, the IPM model projects the future of North Carolina's electricity system based on least-cost outcomes given NRDC's assumptions and allowing the model to build and retire power plants if economic. In the IRP-like reference case, NRDC constrained IPM to better match Duke Energy's Integrated Resource Plan (IRP), requiring the model to build the new units included in the utilities' "No CO2" base case from the IRP. The model was allowed to economically retire existing plants (e.g., coal plants) in the IRP-Like case; only new builds were constrained.

a) Carbon Emissions. In the IRP-like reference case, carbon emissions rise steadily between 2020 and 2030, as a result of new natural gas plants coming online after 2025. In the Optimized BAU reference case, emissions rise steadily until 2030 and then begin declining in 2030.
b) Coal Retirements. Coal capacity declines by 4 GW from 2018 levels by 2022.
c) Solar Additions. Even without new policies, it is economic to add significant new solar capacity, beyond what is currently required by H589. This additional solar replaces retired coal capacity. 8 GW of new utility-scale solar comes online by 2027, with total solar capacity (existing and new) reaching 11.7 GW.
d) Battery Storage. The model finds it economic to build about 1.3 GW of battery storage by 2030, instead of building new natural gas plants to support integration of higher levels of renewables.
e) Cost Impacts. Keeping coal plants online through 2030 is not economic, though they remain online in Duke's latest IRP. As a result, NRDC concludes that cost impacts indicated by its policy cases may turn out to be lower than represented in the modeling results, as the retirement costs would be attributable to least-cost planning, not a policy action.

2.2.4 NC Department of Environmental Quality

Reference Cases: DEQ used two future projections as reference case projections: one compiled for North Carolina's 2019 Greenhouse Gas Inventory (the "Inventory Reference") and the other compiled using the ERTAC EGU Tool (the "ERTAC Reference"). Each reference case is described below.

The Inventory Reference projection was compiled using the method described earlier. A more detailed description of the projection and how it was compiled is available in Section 3.2 of the 2019 Greenhouse Gas Inventory. The key inputs to the projection center on the 2016 EPA Air Markets Program Data (AMPD) hourly data; 2016 EIA Form 923 annual heat input data for EGU's not included in the EPA AMPD data sets; and Duke Energy's 2017 proprietary forecast for annual unit-level heat input provided to NC DAQ. It includes one additional NCGG plant and two additional CT units coming online prior to 2021. For non-Duke units the most recent historic annual heat input is used, averaged over a three-year period with a growth factor of 1.0 applied to future years. Projected load growth, fuel prices, etc. are based on Duke Energy's North Carolina-specific proprietary data imbedded in Duke's forecast. The analysis does not incorporate the Kings Mountain plant, which came online in 2019. It did not include increased solar PV generation due to HB 589. It does not incorporate changes to five coal existing units currently being re-permitted to co-fire coal and natural gas.

DEQ's ERTAC Reference projection was compiled using ERTAC's EGU Tool. The ERTAC projection also relies on projections supplied by Duke Energy about how much units will run in the future. The bases of these projections is proprietary. Other key assumptions and inputs include projections of annual and peak growth rates for fossil fuel units developed for each electricity region using 1) the Energy Information Administration's Annual Energy Outlook (AEO) for annual growth rates, and 2) North American Electric Reliability Corporation (NERC) data for peak growth rates. For North Carolina, ERTAC utilized AEO 2018 high oil and gas reference case to develop annual growth factors. With respect to new plant builds, the ERTAC analysis includes only firm new units and retirements of fossil fuel units that were included in the "business as usual" case developed by NC DAQ and given to NRDC, RFF and NCSU. It does not include new capacity based on Duke's IRP. It includes Kings Mountain NGCC plant coming online in 2019.

NC DAQ specifies low utilization factors for a number of coal plants operating in the state based on historical EPA AMPD data. DEQ believes these units would automatically retire based on a "least-cost" modeling constraint. It does not consider increased solar PV generation due to HB 589, therefore unplanned NGCC generation that was forecast by the model was adjusted downward to account for the additional solar PV generation estimated under HB 589. It does not incorporate changes to five coal existing units currently being re-permitted to co-fire coal and natural gas. It does not incorporate price data because ERTAC is not a least-cost approach to electricity sector modeling.

DEQ's High-Level Takeaways from its Reference Cases.

The DEQ reference case projection includes the following:

a) Carbon Emissions. In the Inventory Reference case, carbon emissions decrease 26% by 2030 from 2016 levels and 47% from 2005 levels. This is largely due to a shift from coal toward natural gas generation. In the ERTAC Reference case, emissions decrease by 24% from 2016 levels by 2030.
b) Generation Mix. In the Inventory Reference, coal use continues to decrease through 2030, a 50% decrease from 2016 levels on a heat input basis, while natural gas use increases by 10% from 2016 levels. In the ERTAC Reference coal use drops off by 75% from 2016 to 2028, while natural gas use doubles.

2.2.5 North Carolina State University

Reference Case: NCSU's modeling runs cover the Duke Energy Progress and Duke Energy Carolina service territories, which include most of North Carolina and a significant section of South Carolina. NCSU's reference case extends from 2017 to 2050, with the years 2020 to 2050 modeled in 5-year time periods. This summary focuses on results out to 2030. To represent variations in supply and demand at the sub-annual level, each year is composed of different time slices to represent different combinations of seasons and times-of-day. In this database, NCSU modeled 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 and assumptions used by NCSU in its reference and policy cases are described in the table below.

Table 3: NCSU's Key Assumptions for Analysis

Data Element	Description and Sources
Electricity demand	As provided in Duke Energy's 2018 IRP, electricity demand is assumed to 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 provides generator vintage and current installed capacity. Rather than individual generating units, existing capacity is described by plant number. Plant heat rates also came from data provided by EIA Form 923.
Solar capacity	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.
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). Fuel prices mostly come from the EIA Annual Energy Outlook (AEO) 2018, though some future coal prices were provided by DEQ.
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 Sioshansi et al. (2014).

NCSU's High-Level Observations from its Reference Case

In the absence of new policy, NCSU's reference case shows a continued downward trend in coal generation with a compensating increase in solar photovoltaic and natural gas generation. Key uncertainties affect these results, including projected natural gas prices, assumed declines in solar costs through 2050, and differences in capacity builds across state lines but within Duke service territories.

a) Carbon Emissions. Reference case emissions rise between 2017 and 2030. Changes in the emissions trajectory largely correspond with the retirement of existing capacity and its replacement with new technology with different emissions characteristics.

b) Generation Mix. Coal and nuclear capacity and generation remain fairly constant out to 2030. Nuclear declines because the reference case does not assume a 20-year relicensing. Natural gas increases significantly starting in 2030 in order to help replace retired coal and nuclear plants, along with significant additions of solar.

2.3 Summary of Reference Cases

A review of the results of the various reference cases reveals some common findings across different models and sets of assumptions.

1. Carbon emissions reductions will require new action. The various reference case runs suggest that carbon emissions may not decrease at all from 2020 to 2030 without new actions. The power sector may achieve a 40% reduction in carbon emissions by 2025, but achieving and sustaining 70% emission reductions by 2030 will require new policy drivers.
2. Solar capacity is economic and will compete favorably even without new action.
3. Economics will drive some additional coal retirements.

3. CEP Modeling: Policy Scenarios

3.1 RFF

3.1.1 Introduction and Policy Runs

RFF analyzed 8 policy scenarios, including one that would promote in-state development of wind and solar and seven others that examined the introduction of emissions trading in North Carolina.

RFF's Policy Runs:

a) RFF's Renewable Energy Policy Run. RFF's renewable energy policy run would double the amount of renewable generation in the state,

b) RFF's Carbon Trading Policy Runs. The carbon emissions trading runs adopt the basic RGGI program design, with cost containment mechanisms. The annual emissions limit declines by 3 percent per year from 2020 levels, as identified by the baseline in the model. The carbon pricing scenarios were differentiated along two dimensions: variations on the way that allowances are distributed in the scenario; and whether the state links its trading program to the larger RGGI market or limits it to North Carolina alone. Allowance distribution was examined across three variations: (i) one scenario with no allowance allocation, but where allowances were auctioned and revenues directed to the general fund (i.e, spent outside the analysis); (ii) allocation to producers using output-based allocation, under which allowances were allocated to all generators except coal and existing renewables based on their share of generation, an approach that provides an incentive for these sources to produce more power to earn valuable emissions allowances; and (iii) allocation to consumers to promote energy efficiency and to reduce the change in electricity prices.

c) RFF's Combination Renewable Policy and Carbon Trading Run. In one scenario RFF combined the renewables policy with carbon trading.

3.1.2 RFF's Key Takeaways from its 8 Policy Runs.

a) Emissions Reductions can be Achieved at Very Low Cost. RFF's emissions trading scenarios achieve cumulative reductions by 2030 of about 150 million tons from 2020 emissions levels. The reductions from the reference case contribute much of this gain. Nonetheless, measured against the improving baseline, by 2030 carbon trading achieves additional cumulative reductions of 81 million tons.

b) Low Allowance Prices Accelerate Emission Reductions under the RGGI Model.
The carbon trading policy is modeled on the RGGI program design, which incorporates a "cost containment reserve" that makes additional allowances available at a specified price, and an "emissions containment reserve" that serves to reduce the number of allowances distributed when the allowance price falls below a certain threshold. For example, no allowances sell at prices below the price floor, and 10 percent of allowances will not sell at prices below the emissions containment reserve. Consequently, the actual quantity of allowances made available in a given year can fall below the declining emission limit path if allowance prices fall below these trigger points (either the emissions containment reserve price step or the price floor) that lead to allowances being withheld

from the market. Low prices yield an additional 4% annual emissions reduction by 2030, and 10.4% additional cumulative reductions over the decade compared to 2020 levels, beyond what is required by the emission limit.

c) Renewable Energy Policy Achieves Greater Emissions Reductions at a Greater Cost than an Emissions Trading Program but also Creates Important Clean Energy Infrastructure for the Future. The renewable energy policy RFF modeled 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, a reduction from 2020 levels and from the baseline, but greater than the emissions outcome achieved by the modeled trading program (approximately 38 MT, varying across scenarios). The renewable energy policy also requires more upfront capital investments than an emissions trading program. The renewable energy policy succeeds in approximately doubling the amount of renewable capacity and generation compared to emissions trading alone, thereby providing important new infrastructure and valuable experience with renewables integration that puts the state in a better position for further decarbonization.

d) A Trading-Ready Program Design Could Link Seamlessly to RGGI. 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 (current RGGI states, plus VA and NJ) so linking results in little shift of emissions, and in fact slightly reduces total emissions in the combined region because of the emissions containment reserve. Linking provides greater resiliency for the program and stability for allowance prices in the face of uncertain weather, fuel prices, etc., while preserving state autonomy and programs.

3.2 Georgetown Climate Center

3.2.1 GCC's Multistate Carbon Trading Scenario.

GCC carried out a single modeling run to determine the benefits and costs of North Carolina implementing a carbon reduction program linked to the RGGI program to keep costs low. In the scenario, North Carolina is assumed to implement a program design similar to RGGI, with a 30% reduction from 2020 to 2030. The program is then linked to the RGGI states, meaning allowances can be traded across state boundaries, allowing the program to find the lowest cost allowances.

3.2.2 Key Takeaways from GCC's Multistate Carbon Trading Scenario.

The results of the GCC policy suggest that North Carolina could limit carbon emissions using a power sector a carbon reduction program and link that program to programs in RGGI states with the following potential outcomes:

a) Carbon emissions. Carbon emissions decrease on a cumulative basis by 32% by 2030 more than the 30% reduction imposed in the emission limit because of trading with other RGGI states. Emissions start at 46 million tons (46% below 2005 levels) in 2022 and are at 33 million tons in 2030 (61% below 2005 levels). These reductions assume no change in the North Carolina or RGGI emissions limits, though historically these limits have been revised downward every 3 to 5 years through program reviews.

b) Allowance value. Carbon trading could generate between $162 and $177 million dollars in allowance value each year during the program. This allowance value can be targeted to clean energy investments or consumer rebates to offset the cost of the program.
c) Wholesale price impacts. Wholesale power prices increase in the modeling by between $0.88 and $1.25 per Megawatt-hour of electricity. Retail price increases are expected to be a small fraction of wholesale price impacts, even before the investment of allowance value is taken into account. In some RGGI states, investment of allowance revenue has been shown to reduce customer bills.
d) Coal generation. With an emission limit in place, North Carolina backs off coal generation more quickly than it does in the reference case.
e) Less New Gas Capacity. In the presence of an emission limit, less new gas capacity is built in the state than in the reference case.

3.3 NRDC

3.3.1 Policy Scenarios Modeled by NRDC

a) Clean Energy Policy. This policy case includes an update renewable portfolio standard that grows from 12.5% in 2021 to 30% by 2030 and an energy efficiency resource standard (EERS). The EERS has a target savings levels of 1.5%. Utilities begin ramping up EE programs in 2020, increasing savings by 0.25% annually and starting from their base (2017) savings of 0.69% (drawn from ACEEE). The state achieves 1.5% by 2024 and maintains this level of savings through the rest of the modeling period.
b) Linked NC Carbon Trading Program. Under this case, NC establishes a carbon trading program that is linked to those of the 11 RGGI states (including Virginia and New Jersey). The program begins in 2021 with a limit of 44.5 million short tons, which equals projected 2020 emissions in the Optimized BAU reference case. This limit declines 3% annually through 2030 and then remains flat. As a proxy for strategies to reduce leakage, the model requires in-state generation to be greater than or equal to level from the Optimized BAU each year.
c) Linked Trading Program and Clean Energy Policy. This policy combines the first two policy scenarios--Linked NC Carbon Trading Program and Clean Energy Policy.

3.3.2 NRDC's Key Takeaways from its Modeled Policy Scenarios

a) To continue reducing carbon emissions and increasing deployment of clean energy resources, new policies are needed. In the reference cases, electricity-sector carbon emissions remain much lower than 2005 emission levels through 2030 due primarily to the retirement of additional coal plants in the next few years, but emissions increase from 2020 to 2030.
b) Emissions are lowest in cases with a linked carbon trading program. The carbon policy ensures that the state continues to see declining emissions after 2025 and incentivizes the reduced generation from coal plants in 2030. The Clean Energy Policy led to relatively flat emissions from 2025 onward.

c) A combination of carbon and clean energy policies drive the most reductions. The combination of a linked trading program, RPS, and EERS drove more reductions than a trading program without complementary clean energy policies and far more reductions than clean energy policies on their own.

d) Policy can achieve emission reductions and increases in clean energy and reduce household electricity bills. By 2030 the combination of carbon and clean energy policies cut the average residential utility bill by almost 2 percent while cutting over 20 million tons of carbon emissions annually, compared to the IRP-Like Reference Case. All modeled scenarios see gradual wholesale price increases over time, as fuel prices (mainly for natural gas) are assumed to increase slightly, and the difference between reference and policy cases is less than $1.50 per MWh. By 2035, wholesale prices under the reference cases are higher or almost the same as prices under policies that drive clean energy and emission reductions. The model projects small increases in retail electricity bills in the near term, but lower or similar bills to the IRP-Like Reference Case in the long-term due to decreased average household consumption (from increased investment in energy efficiency programs).

e) Reducing fossil and increasing solar and energy efficiency is economic across policy cases.

3.4 DEQ's ERTAC Analysis

DEQ used the ERTAC EGU Tool to estimate the emissions reductions that could be achieved if all coal plants were retired and the generation from coal was replaced solely with energy efficiency and renewables. DEQ adjusted the reference cases to estimate the coal and NGCC generation, heat input, and carbon emissions reduced as a result of the policy. DEQ estimated that emissions would drop to 25.3 million tons, or 68% below 2005 levels, by 2030. To accomplish replacement of the coal generation, renewables generation would have to increase by an estimated 17 to 20 thousand GWh. New natural gas was restricted after 2021 in the analysis. The above adjustments were made as inputs to the ERTAC EGU Tool. The key takeaway is that retiring coal reduces emissions, but emissions reductions are greatest when the retired coal is replaced by renewable energy and energy efficiency.

3.5 NCSU

3.5.1 Policy Scenarios Modeled by NCSU.

This summary of the NCSU's modeling focuses on policy scenarios that include policies taking effect before 2030.

a) Energy Efficiency + Solar + Battery Storage Policy Case. This policy case models compliance to HB 589, plus double the potential for energy efficiency improvements. REPS requires that large electric utilities achieve a 12.5% of generation and energy savings by 2022. The law allows 40% of this 12.5% to be satisfied using energy efficiency technologies (EE) for demand reduction, which equates to 5% of total electricity demand. This policy scenario allows EE to account for up to 10% of demand. The minimum required renewables (excluding EE) share is 5.5%. This policy scenario also requires 2% annual growth in solar capacity through 2030. 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.

b) Stringent Carbon Limit. This scenario models the effects of a rigid limit of 25 million metric tons on total CO_2 emissions across Duke Energy's service territory in North Carolina and South Carolina, starting in 2030. The model does not allow the system to adjust imports in order to maximize cost-effective compliance or consider cost implications of the policy, other than energy flows among Duke's territories in the two states. As shown below, this policy drives sustained emission reductions, with reductions beginning in 2025 in anticipation of the 2030 requirements.

c) Clean Energy Standard. This scenario requires at least 60% of the electricity generated in North Carolina come from clean energy sources starting in 2020. This CES would be in lieu of the current REPS policy. This includes energy technologies such as solar, wind, biomass, and landfill gas, as well as nuclear energy and fossil fuels with carbon capture and sequestration (CCS) The policy does not drive emission reductions compared to their reference case before 2030.

d) Extended Nuclear Case. This scenario models the effects of nuclear relicensing to extend nuclear plant lifetimes from 60 to 80 years. With 60-year lifetimes, all of North and South Carolina's nuclear fleet retires by the end of 2040.

e) 10% EV Adoption. This scenario models the impact of increasing electricity demand primarily during off-peak hours in response to electric vehicles driving 10% of all vehicle miles traveled. This case assumes 116 billion vehicle miles traveled per year in NC (US DOT, 2016) through 2050 and uses an efficiency of 4 miles/kWh for EV electricity consumption. The model shows little appreciable effect on electricity demand, the electricity mix, or electricity emissions relative to the base case.

3.5.2 NCSU's Key Takeaways from its Modeling Results

a) Utility-scale solar 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.

b) The scale of solar PV, battery, and gas plant expansion depends upon how long the existing nuclear fleet remains operational. Whether existing nuclear plants retire at the end of a 60- or 80-year lifetime significantly affects the generation mix and carbon emissions.

c) Across all modeled scenarios, battery storage is deployed in 2030 or later. Lower battery costs are required to make battery storage cost-effective for bulk energy time shifting and peak capacity deferral.

d) 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.

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