

Power Sector Carbon Reduction: An Evaluation of Policies for North Carolina

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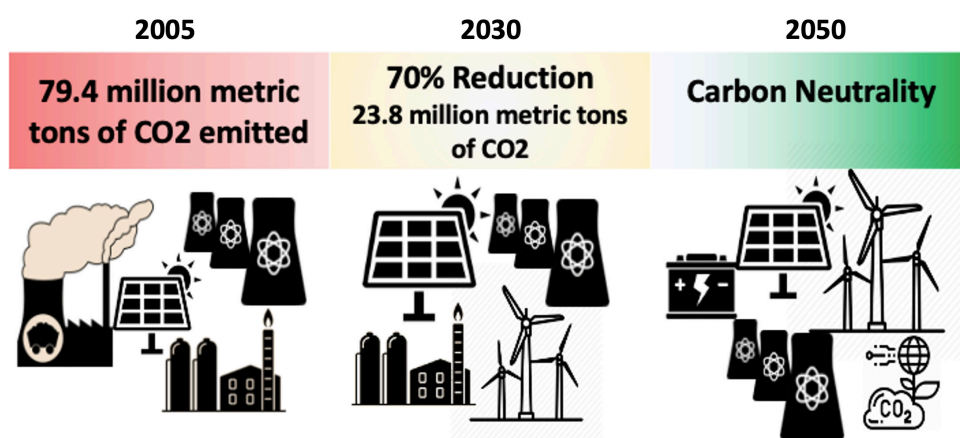
SECTION 1. EXECUTIVE SUMMARY

The North Carolina power sector is poised for transition. Economics have driven big changes on the grid, making cleaner options for electricity generation cost competitive with traditional resources. North Carolina clean energy policies have further enabled the shift into renewable resources. Building on this momentum, Duke Energy Corporation and our state’s rural electric cooperatives have set ambitious climate goals, including “net zero” carbon emissions by 2050.

Well-designed policies can accelerate pollution reduction, make change more affordable for state residents and business, and stimulate job growth. For this reason, the North Carolina Clean Energy Plan (CEP)—developed pursuant to Governor Cooper’s [Executive Order No. 80](#)—recommended the year-long study of carbon reduction policies for the power sector (Recommendation A1). The Duke University Nicholas Institute for Environmental Policy Solutions (Duke Nicholas Institute) and the University of North Carolina’s Center for Climate, Energy, Environment, and Economics (UNC CE3) jointly conducted the study. This report reflects extensive modeling, policy and economic analysis, and stakeholder engagement. It does not make specific recommendations but evaluates different policies and offers options for decarbonizing the grid.

The CEP sets two emissions targets for the electricity used in North Carolina: a 70% reduction in 2005 CO₂ emissions levels by 2030, and carbon neutrality by 2050 (Fig. ES.1). These targets include emissions from in-state electricity generation and electricity imports.

Figure ES.1. Clean Energy Plan Power Sector Emissions Targets



A1 Policy Pathway Definitions

Starting with the CEP list, the A1 group refined options along four pathways or general reduction strategies. All specific policies analyzed in this report derive from these four pathways.

Accelerated coal retirements consider scenarios where different amounts of coal-fired capacity in North Carolina are retired by 2030, beyond any retirements likely to take place for economic reasons. In one scenario, all coal in the state is retired. In another, only less efficient so-called “subcritical” coal units are retired. In the case most often studied, subcritical units are retired and remaining coal units are limited to run just 10% of the year, in times of high electricity demand when other generating resources may not be available.

Carbon adders are a **market-based policy** that account for the costs to society imposed by a power plant that emits carbon dioxide (CO₂), including power plants run on coal, natural gas, oil, or biomass. These carbon adders are not actually paid by the utility but used in the decision-making process. If a utility could build a new natural gas plant or a solar photovoltaic (PV) farm, for instance, a carbon adder would make the natural gas plant look more expensive relative to a project that will not emit any pollution. Carbon adders can also be applied to decisions about which power plants to run to meet electricity demand at any given time. This can be an effective way to account for carbon pollution within a traditional rate-regulated state like North Carolina, where the Utilities Commission considers “least cost” to consumers when approving utility plans.

Another **market-based policy** studied in this report involves joining a **carbon market like the Regional Greenhouse Gas Initiative** (RGGI). Each state that participates in the RGGI market sets a budget of CO₂ allowances that shrink every year. For every ton of CO₂ that a power plant emits, it must hold one allowance. Generators may buy or

sell allowances but must never emit more than the number of allowances they hold. The program works somewhat like a game of musical chairs—each year fewer tons of CO₂ may be emitted from all power generation across the participating states. RGGI scenarios studied in this report test different stringency levels and situations where North Carolina might raise revenues by selling CO₂ allowances. All variations feature an allowance budget that gets tighter each year from 2023–2030 and then remains level, reflecting that the RGGI states have not yet set budgets for the following years. However, it is widely expected that the allowance budget would continue to get more stringent after 2030.

The first three policy pathways may be characterized as “push” policies in that they seek to push carbon-intensive resources or CO₂ emissions out of the system. By contrast, the fourth pathway encompasses **clean energy standards** (CES), “pull” policies that work to draw in new clean resources. These standards can be technology neutral, allowing any non-emitting resource from solar and wind to nuclear and fossil with carbon capture to qualify, or require specific types of resources to meet part of the standard. (The report analyzes **offshore wind** and **energy efficiency** (EE).) The standard CES policies modeled in this report require an increasing percentage of electricity sales in North Carolina to be met with clean energy built in the state. Alternative cases set a declining rate of emissions from the entire North Carolina power generation fleet.

Push policies are less efficient at bringing in clean generation; pull policies are less efficient at reducing emitting generation. Combining them can bring advantages to the system. For this reason, the report also studies the effects of combining a CES with the other policies.

The CEP proposed several potential policy pathways for achieving these targets:

- (1) Accelerated coal retirements;
- (2) Market-based policies that put downward pressure on CO₂ emissions from the power sector;
- (3) Clean energy policies; and
- (4) Combinations of these policies.

Using these policies as a departure point, A1 stakeholders defined specific policies to analyze for possible application in North Carolina (Table ES.1). (Stakeholder organizations, and the individuals who served in A1 working groups, are identified in **Appendix A**.)

Key Findings

- The electricity system appears to be at a “tipping point” where small changes in gas prices or renewables costs can sway the balance between new capacity (i.e., gas turbines, renewables, and battery installations).
- CO₂ emissions from North Carolina’s electric power sector will continue to decline as coal plants retire. However, new policies are necessary to achieve the CEP 2030 and midcentury emissions targets. If carefully designed, these policies can make emissions reductions more cost-effective and affordable, and drive positive economic development across the state.
- Coal retirement, carbon market, and carbon adder policies achieve reductions by lowering or “pushing out” in-state fossil generation, while CES policies increase in-state renewable generation, thus “pulling in” new resources to the grid. Combination policies can accomplish both outcomes more efficiently.
- Offshore wind requirements are projected to increase the cost of a CES but could drive economic development in supply chains and maritime trades.¹
- Some policies can achieve relatively deep reductions in local air pollutants, including coal retirements or CES combined with RGGI and other “push” policies. This can improve health outcomes in fenceline communities and is important when considering equity in policy design.

Key Variables That Could Impact Emissions and Costs

- The level of electricity imports into North Carolina can have significant impacts on policy costs and in-state emissions.
- Amortizing the cost of renewable energy over a 30-year period rather than a 20-year period could lower cost estimates 21–64% across most policy scenarios.

1. This report did not study the economic opportunities of offshore wind. However, based on forecasts of East Coast offshore wind installed capacity, a recent study projects nearly \$100 billion in economic value for North Carolina. See BVG Associates, Building North Carolina’s Offshore Wind Supply Chain (2021), https://files.nc.gov/nccommerce/documents/Polymaker-Reports/Report_North-Carolina-OSW-Supply-Chain-Assessment_BVGAssociates_asPublished-Mar3-2021.pdf.

Electricity Capacity versus Generation

Electricity capacity refers to the maximum amount of electricity that a generator could produce, based on the size of the resource. Capacity is usually measured in megawatts—so for instance, Duke Energy has a 920-megawatt (MW) natural gas-fired power plant at the old H.F. Lee Facility in Wayne County.

Electricity generation refers to the amount of electricity that is actually produced by a generator. Generation turns on two factors—the availability of the generator, and the electricity demand on the system. A generator may not be available all the time, for instance if it needs to be taken off line for repairs, faces fuel supply shortages, or

cannot run after the sun has set (in the case of a solar generator). Even if a generator could run, it may not run full-bore if other, less costly emitting resources are running at sufficient levels to meet demand for electricity.

When this report refers to capacity, it is referring to the total number and size of generating installations in North Carolina. When this report refers to generation, it is describing which of the generating installations are running and at what levels throughout a given year. Capacity and generation are important metrics to consider when comparing policies.

- Additional policy design choices can mitigate costs or allocation of costs. For example, the modeled CES required all qualifying renewable energy generation to occur within North Carolina. A more flexible policy could lower costs significantly but with possible emissions implications and a dampening of the economic development opportunities created by a “build it in North Carolina” approach.
- The absolute and relative costs of natural gas, renewable energy, and energy storage will continue to change. Even slight changes could impact costs and emissions.

The analysis in this report relies on two power sector capacity planning models—the consulting firm ICF’s proprietary Integrated Planning Model (IPM) and the Dynamic Integrated Economy/Energy/Emissions Model (DIEM), developed at the Duke Nicholas Institute. IPM is familiar in the electric utility world and is relied on by regulators, utilities, and environmental organizations. RGGI states also rely on IPM for analysis of their carbon market. Meanwhile, as a robust in-house model at Duke University, DIEM could be used in a much more flexible way to test multiple policy variations and sensitivities. While the A1 Working Groups helped to coordinate the data and assumptions, differences remain in model structures and assumptions that—while leading to different outcomes—are nonetheless generally consistent. Modeling divergences, along with analyses to test the sensitivity to particular variables, underscore the uncertainties at play here and the role different assumptions play in policy outcomes.

This Executive Summary focuses on the stand-alone policies and clean energy standard (CES) combinations listed in Table ES.1. Section 6 of the report expands the analysis to the policy variations shown in the second part of the table, and **Appendix F** provides additional modeling and sensitivity analyses.

Table ES.1. Modeled Policy Cases and Variations

Category	Policy Cases	Model	
		IPM	DIEM
Standalone	Baseline	x	x
	Accelerated Coal Retirement (<i>Option #2 below</i>)	x	x
	RGGI with 3% decline per year to 2030 (<i>steady after 2030</i>)	x	
	RGGI with 2030 CEP target (<i>steady after 2030</i>)	x	
	RGGI w/2030 CEP target & EE (<i>steady after 2030</i>)	x	
	CO2 Adder on New Capacity (\$6/ton + 7%/year)	x	x
	CO2 Adder on Generation (\$6/ton + 7%/year)		x
	CO2 Adder on Generation w/import border adjust (\$6/ton + 7%)		x
	CO2 Adder on Generation - USA wide (\$6/ton + 7%)		x
	CES on NC Retail Sales (70% in 2030, 95% in 2050)	x	x
CES Combinations (NC Sales - 70% in 2030, 95% in 2050)	CES on USA-wide Retail Sales (70% in 2030, 95% in 2050)		x
	CES + Coal Retirement	x	x
	CES + RGGI	x	
	CES + RGGI + Offshore Wind	x	
	CES + Carbon Adder on New Capacity	x	x
	CES + Carbon Adder on Generation	x	x
	CES + Offshore Wind	x	x
Category	Policy Variations	IPM	DIEM
Coal Retirement	Option #1 (<i>retire all subcritical by 2030</i>)		x
	Option #2 (<i>retire sub, limit supercrit to 10%, Rogers #6 on gas</i>)	x	x
	Option #3 (<i>retire all coal by 2030, Rogers #6 on gas</i>)		x
CO2 Adder on Generation	CEP Cap: "UK" approach		x
	\$5/ton + \$5/year		x
	\$5/ton + \$7/year		x
	Federal Social Cost of Carbon (SCC) in 2016 and 2017		x
	\$13/ton + 7%/year		x
	\$13/ton + 7%/year with import adjustment		x
	\$13/ton + 7%/year - USA		x
Clean Energy Standards	Sales: 60% in 2030, 95% in 2050		x
	Sales: 65% in 2030, 95% in 2050		x
	Sales: 75% in 2030, 95% in 2050		x
	Sales: 65% in 2030, 90% in 2050		x
	Sales: 65% in 2030, 100% in 2050		x
	Generation: 70% in 2030, 95% in 2050		x
	USA Generation: 65% in 2030, 95% in 2050 – USA wide		x
	Emissions Rate Goal		x

Any policy or policy combination would be implemented in a system marked by unprecedented change. Since 2010, more than 100 gigawatts (GW) of coal capacity has retired in the United States. That number includes nearly 3 GW in North Carolina alone—enough to power 900,000 homes. Significant declines in natural gas prices and continuing reductions in the costs of new

solar photovoltaic (PV), wind, and battery storage capacity have contributed to this shift. Given this, even modest market-based policies described in this report—a carbon adder that starts at \$6/ton of CO₂ and increases 7% each year, or a RGGI market price of \$5/ton—move the system. Moreover, results in this report do not reflect more recent developments such as the energy impacts of COVID-19, the December 2020 extensions for renewable energy tax credits, and a change in federal administration to one pledging ambitious climate policy action.

The policies cover a wide range of alternatives, but could be defined differently and would result in different emissions, costs, or influences on the resources built and run to supply electricity to North Carolina. For instance, the modeled coal retirement policies assume specific additional retirements of the state's coal units by 2030. Similarly, the modeled RGGI scenarios increase in stringency until 2030 and then level off, although it is expected that the RGGI states will agree to a further reduction of emissions after that time. By contrast, the modeled carbon adders and clean energy standards grow more stringent to 2050. After studying the comparative impacts of one type of policy versus another, North Carolina could choose to retire coal units sooner or later, set more stringent CO₂ reduction targets beyond 2030 in the RGGI program, or set carbon adders or CES at different levels of ambition. In addition, North Carolina might opt to rely more heavily on EE as a cost-effective component to any climate policy. This report incorporates discussions of EE but modeling was limited by the fact that North Carolina does not currently have an EE supply curve to predict the cost of deploying different types or levels of EE in this state.

Model results are projections about electricity system responses to various policy scenarios. As with any modeling exercise, the results are not meant to be relied upon for their absolute values, but serve as useful directional signals showing relative impacts of different policy approaches on NC's electricity system. Moreover, the impacts estimated and reported here are not comprehensive. For instance, policy cost estimates do not include the costs of inaction on climate change, or the health and economic benefits of reducing air pollution generally.

Results of Electricity Modeling

Outputs from the IPM and DIEM models allow comparisons of the relative emissions reductions (CO₂ and the local pollutants, NO_x and SO₂) and systems costs of each modeled policy. These models also describe the policy's relative impacts on the electricity capacity and generation mix in North Carolina over time. Meanwhile, ICF conducted rate/bill impact analysis for a representative sampling of policies, and reported relative jobs and Gross State Product (GSP) numbers for that policy subset using the Regional Economic Models, Inc. (REMI) tool. An expert Technical Working Group helped to identify modeling inputs and assumptions.

The report also reflects regular discussions on policy design and concerns about affordability and equity among A1 stakeholders and a Policy Working Group representing utilities, environmental and environmental justice organizations, low-income consumers, industry, clean energy companies, government, and academia.² While interactions with these groups were extremely helpful, this is not a consensus document. Moreover, participation in the process does not

2. See Section 3 for more detail on the stakeholder process and analysis undertaken for this report.

imply endorsement of any of the report's findings. All final decisions regarding policy choices, assumptions, and report language are the responsibility of the authors.

Some of the key questions to pose when evaluating a carbon policy include:

- Will policies drive retirement of coal more quickly than under business as usual?
- What will replace retiring coal capacity—gas, renewables, battery storage, emerging technologies, or combinations of technologies to keep the system reliable?
- To what extent could a policy lead to increased reliance on electricity imports?
- Do some policies achieve or nearly achieve the near-term target but set a trajectory that could make it tougher to achieve a carbon neutral grid by midcentury?

In addition to these basic questions regarding the impact of different climate policies on the electric capacity and generation mix serving North Carolina, this report attempts to answer some next-order questions that follow on from potential changes in the industry such as:

- What do different policies cost and who bears these costs?
- What are the local air pollution implications of policies?
- Which policies may be net job creators?
- Which policies drive positive economic development in the state?
- How can any policy be designed to be more affordable, and more equitable?

Emissions and Systems Costs

Table ES.2 summarizes the CO₂ reductions associated with specific policy options. The four left-side columns of results focus on emissions from in-state electricity generation. The four right-side columns incorporate emissions estimates associated with imported electricity, since the CEP targets cover emissions associated with all electricity consumed in North Carolina.

By 2030, in-state power sector emissions under “business as usual” baseline forecasts are 32 million metric tons of CO₂ (MMTCO₂) in IPM and 28 MMTCO₂ in DIEM, representing a 56% or 62% reduction from 2005 in-state emissions respectively. IPM estimates another 5 MMTCO₂ from electricity imports, for a total of 37 MMTCO₂ in 2030, compared with 31 MMTCO₂ in DIEM. IPM, which selected more coal generation and fewer renewables in the baseline than DIEM, reports larger absolute reductions in emissions across policy cases that nonetheless remain further from CEP targets. Neither model suggests the system can meet the 2030 CEP target without additional policies.

Policies that achieve the 2030 CEP target in at least one of the models include:

- Carbon adders on generation (beginning at \$6/ton and growing at 7% per year);
- A CES (with or without an offshore wind requirement); and
- Combination policies that start with a CES and also include either accelerated coal retirements, RGGI, or a carbon adder.

Among the stand-alone options, the **coal retirement** and **RGGI** policies drive some of the deepest in-state reductions by 2030, with RGGI providing the quickest reductions prior to 2030. However, these two policies increase system reliance on electricity imports. Moreover, emission reductions for these two options stagnate after 2030, again because of the policy definitions (i.e., assuming the CO₂ budget in RGGI will remain constant after 2030).

The modeled **carbon adder on new capacity** investment decisions has relatively small impacts on emissions by 2030 since it largely functions to preclude new investments in combustion turbines, but does not address emissions from existing fossil units. Reductions for the policy expand after 2030 as the adder becomes sufficiently robust to prevent construction of additional new turbines that would have appeared without the policy. Applying the same level of adder as a **carbon adder on generation** decisions achieves the 2030 CEP target.

A CES that aims for 70% clean generation in 2030 (and 95% clean by 2050) falls short of the 2030 CEP target in IPM, but meets it in DIEM (helped along by the additional renewables in that model's baseline). If a national CES were implemented, lower power sector emissions in North Carolina in DIEM suggests that the state would be better positioned to construct renewables than other states (and can then sell CES credits to a national market). Most policies that combine the 70% CES policy with other actions achieve CEP 2030 goals in IPM—and exceed them in DIEM. The greatest reductions are from the CES with the carbon adder on generation.

Looking further into the future, measures of cumulative reductions through 2050—in percentage terms compared to the baseline—vary across the two models, again because baseline emissions in DIEM are significantly lower than in IPM (see Section 6). As a result, policies such as a CES do less in DIEM to meet clean energy goals since baseline adoption of clean generation is higher. (Keep in mind when examining these 2050 results that the RGGI policies stop increasing in stringency in 2030, while the CES and carbon adders continue expanding through 2050.)

Table ES.2. Emissions in IPM and DIEM (MMTCO₂ and % Change)

IPM Model	In-State				Total (w/ Import Adjustment)			
	% Reduced		% Reduced		% Reduced		% Reduced	
	2030 (MMTCO ₂)	from 2005	Cum to 2050	from Baseline	2030 (MMTCO ₂)	from 2005	Cum to 2050	from Baseline
Policy Cases								
Baseline	32.4	56%	813		37.2	53%	946	
Accelerated Coal Retirement	23.7	68%	698	14.2%	30.0	62%	848	10.4%
RGGI - 3% decline/yr to 2030	26.6	64%	650	20.0%	32.5	59%	803	15.1%
RGGI with 2030 CEP target	24.6	66%	640	21.3%	30.9	61%	795	15.9%
RGGI w/2030 CEP target & EE	24.3	67%	636	21.8%	30.1	62%	785	17.0%
CO2 Adder on New Capacity	30.2	59%	734	9.8%	35.4	55%	893	5.6%
CES on NC Retail Sales	26.1	64%	633	22.1%	26.1	67%	678	28.3%
CES + Coal Retirement	18.2	75%	555	31.7%	21.8	72%	632	33.2%
CES + RGGI	20.4	72%	516	36.6%	23.5	70%	599	36.7%
CES + RGGI + Offshore Wind	19.8	73%	514	36.7%	23.1	71%	579	38.8%
CES + CO2 Adder on New Cap	26.3	64%	631	22.4%	26.3	67%	677	28.4%
CES + CO2 Adder on Gen	14.6	80%	342	58.0%	18.8	76%	474	49.9%
CES + Offshore Wind	25.8	65%	645	20.6%	25.8	68%	673	28.8%

DIEM Model	In-State				Total (w/ Import Adjustment)			
	% Reduced		% Reduced		% Reduced		% Reduced	
	2030 (MMTCO ₂)	from 2005	Cum to 2050	from Baseline	2030 (MMTCO ₂)	from 2005	Cum to 2050	from Baseline
Policy Cases								
Baseline	28.0	62%	626		30.9	61%	696	
Accelerated Coal Retirement	23.6	68%	571	8.8%	26.9	66%	644	7.4%
CO2 Adder on New Capacity	27.1	63%	577	7.7%	30.5	62%	646	7.1%
CO2 Adder on Generation	13.3	82%	312	50.1%	20.0	75%	460	34.0%
CO2 Adder on Gen w/import adj	14.2	81%	357	43.0%	19.5	75%	458	34.2%
CO2 Adder on Gen - USA wide	15.9	78%	391	37.4%	19.3	76%	448	35.6%
CES on NC Retail Sales	20.9	71%	537	14.1%	23.6	70%	603	13.3%
CES on USA-wide Retail Sales	12.2	83%	275	56.1%	13.7	83%	300	56.8%
CES + Coal Retirement	18.3	75%	497	20.6%	20.9	74%	564	19.0%
CES + CO2 Adder on New Cap	20.5	72%	516	17.6%	23.2	71%	579	16.9%
CES + CO2 Adder on Gen	11.1	85%	280	55.3%	15.9	80%	400	42.5%
CES + Offshore Wind	18.8	74%	525	16.1%	21.1	73%	579	16.8%

Note: Percentage reductions in bold are those that meet 2030 CEP targets for total emissions.

Table ES.3 presents the costs of providing electricity to the grid (e.g., capital costs of new construction, operating and fuel costs).³ Costs are expressed in net present value (NPV) terms,

3. Costs include, for example, the costs of connecting new renewables to the grid. However, estimates of policy costs would not include general improvements to the grid that may be necessary regardless of any specific CEP policies.

compared to the costs of providing electricity under “business as usual.”⁴ Both models initially assume a 30-year book life for natural gas units and a 20-year book life for renewables,⁵ which can make renewables appear more expensive by reducing the number of years over which payments for the capital investments are spread. Given the importance of this assumption in determining policy costs, DIEM results present alternative cases that assume a 30-year book life for renewables (similar to the default assumption in the NREL Annual Technology Base).

Policy cost highlights:

- **Accelerated coal retirements** raise NPV costs by less than 1% over baseline system costs through 2050 (most changes—in both costs and emissions reductions—occur by 2030). Costs per ton of emissions reduced, based on either in-state emissions or total emissions adjusted for imports, are on the lower end of the policy estimates.
- **RGGI costs**—either as a change in NPV or costs per ton—are among the lowest of the options (again bearing in mind that the policy is focusing on changes in the system up to 2030 and have more limited effects afterwards because of the assumption that RGGI budgets do not continue to tighten).
- Costs for a **carbon adder on new capacity** are low, but emissions reductions are also limited.
- The models have varying estimates of policy costs for a **CES over NC retail sales**. (These estimates will be very sensitive to assumptions about renewables’ book life since they are focused on increasing renewables.)
- **Adding coal retirements to a CES** results in a minor cost increase, but costs per ton reduced are lower.
- Adding an **offshore wind requirement to a CES** raises costs (although these estimates are reduced by more than 30% in DIEM when using the assumption of a 30-year book life for renewables).
- How policy costs are calculated matters—the assumption of a 30-year book life for renewables lowers cost estimates for many policies in DIEM by 21–64%.

4. NPV metrics allow the annualization of capital payments over time, similar to how such costs would be experienced by firms that use either equity or debt to finance new construction. While expressing costs in this fashion is consistent with how electricity models solve for cost-effective methods of supplying electricity, they make it difficult to meaningfully express costs over a short time horizon—i.e., attempting to show NPV costs only through a year such as 2030 would miss most of the capital payments for units installed to meet any 2030 emissions goals.

5. Book life is essentially the number of years over which capital payments are annualized, thus, longer book life extends payments and lowers the estimated net present values of policy costs, especially for policies that involve high levels of renewables installations. Note that book life is largely an accounting technique and is not necessarily tied directly to the actual service life of a generating unit.

Table ES.3. Policy Costs

IPM Model	Renewables: 20-year booklife			
	NPV to 2050 (\$ billion)	NPV to 2050 (% change)	\$/ton Reduced Based on In-State	\$/ton Reduced Based on Total Emis
Policy Cases				
Accelerated Coal Retirement	\$0.63	0.6%	\$10	\$11
RGGI with 3% decline/year to 2030	\$0.51	0.5%	\$5	\$6
RGGI with 2030 CEP target	\$0.56	0.6%	\$5	\$6
RGGI w/2030 CEP target & EE	(\$0.78)	-0.8%	(\$7)	(\$8)
CO2 Adder on New Capacity	\$0.25	0.3%	\$7	\$10
CES on NC Retail Sales	\$2.38	2.4%	\$25	\$17
CES + Coal Retirement	\$2.51	2.6%	\$18	\$15
CES + RGGI	\$2.62	2.7%	\$15	\$13
CES + RGGI + Offshore Wind	\$10.10	10.4%	\$57	\$49
CES + CO2 Adder on New Capacity	\$2.73	2.8%	\$29	\$20
CES + CO2 Adder on Generation	\$4.08	4.2%	\$15	\$16
CES + Offshore Wind	\$10.04	10.3%	\$116	\$72

DIEM Model	Renewables: 20-year booklife				Renewables: 30-year booklife			
	NPV to 2050 (\$ billion)	NPV to 2050 (% change)	\$/ton Reduced Based on In-State	\$/ton Reduced Based on Total Emis	NPV to 2050 (\$ billion)	NPV to 2050 (% change)	\$/ton Reduced Based on In-State	\$/ton Reduced Based on Total Emis
Policy Cases								
Accelerated Coal Retirement	\$0.28	0.3%	\$8	\$9	\$0.26	0.3%	\$7	\$8
CO2 Adder on New Capacity	\$0.38	0.5%	\$16	\$17	\$0.25	0.3%	\$11	\$11
CO2 Adder on Generation	\$2.90	3.5%	\$15	\$20	\$2.23	2.8%	\$11	\$15
CO2 Adder on Gen w/import adjust	\$4.54	5.5%	\$27	\$32	\$2.75	3.4%	\$16	\$19
CO2 Adder on Gen - USA wide	\$4.49	5.5%	\$34	\$33	\$3.32	4.1%	\$25	\$24
CES on NC Retail Sales	\$3.81	4.6%	\$65	\$62	\$2.18	2.7%	\$37	\$36
CES on USA-wide Retail Sales	\$2.72	3.3%	\$14	\$12	\$1.31	1.6%	\$7	\$6
CES + Coal Retirement	\$4.10	5.0%	\$49	\$48	\$2.45	3.1%	\$29	\$29
CES + CO2 Adder on New Capacity	\$3.40	4.2%	\$49	\$47	\$1.21	1.5%	\$17	\$17
CES + CO2 Adder on Generation	\$6.11	7.5%	\$28	\$33	\$4.16	5.2%	\$19	\$22
CES + Offshore Wind	\$6.45	7.9%	\$96	\$85	\$4.22	5.3%	\$63	\$56

Table ES.4 presents projected changes in two local air pollutants, nitrogen oxides (NO_x) and sulfur dioxide (SO₂). These outcomes may be of particular importance to communities experiencing the health consequences of these emissions. The projected trends for these pollutants largely track projected reductions in CO₂. Once again, **accelerated coal retirements** drive some of the deepest reductions in 2030 in NO_x and SO₂ of the stand-alone policies studied but by 2040 have more limited impact. Joining **RGGI** and setting the CO₂ budget at 22 million tons by 2030 (“RGGI with CEP 2030 target”) reduces NO_x and SO₂ more than a CES in 2030, but because the modeled RGGI policies did not increase in stringency beyond that year, by 2040 the CES outpaces RGGI in NO_x reductions and matches RGGI in SO₂ performance.

There are also some notable differences between CO₂ and local pollutant outcomes. For instance, **carbon adder on new capacity** slightly increases NO_x emissions over the baseline in 2030 in IPM (SO₂ emissions in IPM and both pollutants in DIEM fall slightly). The deepest reductions in local

pollutants are achieved by policies that directly impact fossil fuel-fired generation: **carbon adders on generation** or **CES in combination with RGGI, coal retirement, or a generation adder**.

Table ES.4. NO_x and SO₂ Emissions in North Carolina (1000 Metric Tons)

Policy Cases	IPM Model				DIEM Model			
	NO _x		SO ₂		NO _x		SO ₂	
	2030	2040	2030	2040	2030	2040	2030	2040
Baseline	15.6	5.8	4.6	0.7	13.9	4.4	4.1	0.3
Accelerated Coal Retirement	7.7	4.6	0.8	0.0	9.5	4.2	0.8	0.0
RGGI with 3% decline per year to 2030	12.1	4.7	3.4	0.3				
RGGI with 2030 CEP target	10.2	4.7	2.8	0.3				
RGGI w/2030 CEP target & EE	9.9	4.7	2.7	0.3				
CO ₂ Adder on New Capacity	15.7	5.5	4.7	0.7	13.3	2.5	4.2	0.3
CO ₂ Adder on Generation					3.4	0.8	0.0	0.0
CO ₂ Adder on Generation w/import adjust					4.0	0.9	0.0	0.0
CO ₂ Adder on Generation - USA wide					5.0	0.7	0.0	0.0
CES on NC Retail Sales	11.4	3.7	3.5	0.3	9.9	3.4	2.7	0.3
CES on USA-wide Retail Sales					3.1	0.1	0.1	0.0
CES + Coal Retirement	5.6	3.3	0.5	0.0	7.2	3.2	0.8	0.0
CES + RGGI	7.6	3.7	1.5	0.3				
CES + RGGI + Offshore Wind	7.1	3.6	1.3	0.2				
CES + Carbon Adder on New Capacity	11.7	3.9	3.5	0.3	9.2	2.4	2.5	0.2
CES + Carbon Adder on Generation	3.3	1.6	0.0	0.0	2.4	0.8	0.0	0.0
CES + Offshore Wind	11.4	4.4	3.3	0.3	8.0	2.8	2.0	0.2

Capacity Changes

Tables ES.5 and ES.6 show the changes in capacity for 2030 and 2050 under different policies, relative to 2023. The first row of each table shows capacity changes for the baseline forecasts (i.e., absent new climate policies). By 2030 in the baseline, IPM has retired 4.3 GW of coal and built 4.9 GW of new gas turbines, but has built no new renewables beyond the requirement of House Bill (HB) 589. DIEM's baseline retires less coal and builds gas turbines, solar PV, and a small amount of onshore wind. Although the models allow uneconomic nuclear plants to retire, this does not happen in the baseline or policy results.

Policy highlights for 2030:

- New gas turbines are used to meet **baseline** demand growth and reliability needs in IPM, while DIEM adds a mix of turbines, solar, and some onshore wind.
- **Accelerated coal retirements** are replaced by new turbines.
- **RGGI** policies lead to less construction of new gas turbines, but also have fewer coal retirements than in the baseline. RGGI does not lead to new renewables by 2030.
- A **carbon adder on new fossil investments** eliminates new turbines.
- **Carbon adders on generation** drive some additional solar and onshore wind.

- A 70% CES encourages a significant expansion of renewables, but has limited effect on existing coal plants.
- **CES combination policies** generally drive more coal retirements and higher renewables.
- IPM expanded battery storage in the CES policies. DIEM sees fewer battery installations because it assumed larger (and thus more expensive) batteries are tied to its paired solar/battery units than was the case in IPM (see the sensitivity analyses below to get a sense of how battery installations can vary across model assumptions).
- A **CES with an offshore wind** requirement reduces solar and expands turbines in IPM. In DIEM, offshore wind replaces a combination of solar and onshore wind.

Table ES.5. NC Capacity Changes by 2030 in IPM and DIEM (GW)

Policy Cases	IPM Model					
	Coal	Gas Turbine	Solar*	Onshore Wind	Offshore Wind	Battery Storage
Baseline	-4.3	4.9	0.0	0.0	0.0	0.0
Accelerated Coal Retirement	-7.0	7.9	0.0	0.0	0.0	0.0
RGGI with 3% decline/year to 2030	-3.7	2.9	0.0	0.0	0.0	0.0
RGGI with 2030 CEP target	-3.7	2.5	0.0	0.0	0.0	0.0
RGGI w/2030 CEP target & EE	-3.7	2.6	0.0	0.0	0.0	0.0
CO2 Adder on New Capacity	-3.0	0.0	0.0	0.0	0.0	0.0
CES on NC Retail Sales	-4.9	0.4	13.2	1.2	0.0	2.8
CES + Coal Retirement	-5.8	0.9	12.9	1.4	0.0	2.9
CES + RGGI	-5.9	0.9	13.0	1.3	0.0	3.0
CES + RGGI + Offshore Wind	-5.3	1.3	9.0	0.5	2.8	2.0
CES + CO2 Adder on New Capacity	-4.5	0.0	13.2	1.2	0.0	2.7
CES + CO2 Adder on Generation	-6.7	0.5	12.9	1.5	0.0	3.1
CES + Offshore Wind	-5.0	1.5	9.0	0.5	2.8	1.9

Policy Cases	DIEM Model					
	Coal**	Gas Turbine	Solar*	Onshore Wind	Offshore Wind	Battery Storage
Baseline	-2.4	1.7	3.9	0.3	0.0	0.0
Accelerated Coal Retirement	-5.6	4.2	3.9	0.3	0.0	0.0
CO2 Adder on New Capacity	-2.4	0.0	3.9	0.3	0.0	0.0
CO2 Adder on Generation	-2.9	0.0	3.9	1.8	0.0	0.0
CO2 Adder on Gen w/import adjust	-2.8	0.9	5.8	2.1	0.0	0.0
CO2 Adder on Gen - USA wide	-2.7	2.2	5.9	2.2	0.0	0.0
CES on NC Retail Sales	-2.5	0.8	11.2	2.5	0.0	0.0
CES on USA-wide Retail Sales	-2.7	1.5	9.8	2.9	0.0	0.0
CES + Coal Retirement	-5.6	3.5	10.9	2.7	0.0	0.0
CES + CO2 Adder on New Capacity	-2.5	0.0	12.8	1.7	0.0	0.9
CES + CO2 Adder on Generation	-2.9	0.2	11.1	2.6	0.0	0.0
CES + Offshore Wind	-2.5	0.7	8.0	1.2	2.8	0.0

* New solar capacity excludes required installations under HB589

** Change in coal summer capacity shown for DIEM.

Policy highlights for 2050:

- All coal units have reached the end of their depreciation lives and are forced out in the **baseline** forecast (and all policy cases).
- **Accelerated coal retirements** and **RGGI** have limited impacts on new turbines. RGGI shows some increases in solar PV by 2050.
- A **carbon adder on new capacity** prevents around 12 GW of new turbines by 2050. The turbines are replaced by a mix of solar and batteries.
- **Carbon adders on generation** don't prevent installation of gas turbines for reliability purposes, although utilization rates are lower. Adders on generation encourage a combination of solar and batteries.
- The **CES** policy—which reaches 95% in 2050—drives about 30 GW of in-state solar, along with some batteries; a **CES with an offshore wind** requirement shifts some of that solar capacity into wind.
- **CES combination policies** reduce construction of new turbines and shift the industry towards batteries.
- Generally, higher penetration of battery storage complements solar installations and displaces gas.

Table ES.6. NC Capacity Changes by 2050 in IPM and DIEM (GW)

Policy Cases	IPM Model					
	Coal	Gas Turbine	Solar*	Onshore Wind	Offshore Wind	Battery Storage
Baseline	-10.2	12.5	10.9	3.9	0.0	5.8
Accelerated Coal Retirement	-10.2	12.2	11.3	3.9	0.0	6.2
RGGI with 3% decline/year to 2030	-10.2	11.0	14.8	3.9	0.0	7.4
RGGI with 2030 CEP target	-10.2	11.0	14.8	3.9	0.0	7.4
RGGI w/2030 CEP target & EE	-10.2	11.4	13.9	3.9	0.0	7.0
CO2 Adder on New Capacity	-10.2	0.0	15.9	3.9	0.0	8.3
CES on NC Retail Sales	-10.2	4.2	32.2	3.9	0.0	11.5
CES + Coal Retirement	-10.2	4.5	32.2	3.9	0.0	11.6
CES + RGGI	-10.2	4.1	32.2	3.9	0.0	11.8
CES + RGGI + Offshore Wind	-10.2	7.2	21.5	1.4	8.0	7.5
CES + CO2 Adder on New Capacity	-10.2	0.0	32.2	3.9	0.0	12.5
CES + CO2 Adder on Generation	-10.2	3.7	33.6	3.9	0.0	13.8
CES + Offshore Wind	-10.2	7.3	20.9	1.8	8.0	7.5

Policy Cases	DIEM Model					
	Coal**	Gas Turbine	Solar*	Onshore Wind	Offshore Wind	Battery Storage
Baseline	-9.9	11.8	12.9	1.8	2.4	1.9
Accelerated Coal Retirement	-9.9	12.3	12.7	1.8	2.4	1.9
CO2 Adder on New Capacity	-9.9	0.0	30.3	1.2	1.9	10.3
CO2 Adder on Generation	-9.9	10.2	15.0	2.2	3.4	6.3
CO2 Adder on Gen w/import adjust	-9.9	5.7	30.3	2.4	3.4	9.5
CO2 Adder on Gen - USA wide	-9.9	7.4	22.3	2.2	2.0	7.6
CES on NC Retail Sales	-9.9	10.3	27.4	2.7	3.4	4.4
CES on USA-wide Retail Sales	-9.9	10.0	30.6	2.9	3.1	8.1
CES + Coal Retirement	-9.9	10.2	27.2	2.8	3.4	4.5
CES + CO2 Adder on New Capacity	-9.9	0.0	35.3	1.7	1.8	10.5
CES + CO2 Adder on Generation	-9.9	9.5	29.1	2.7	3.4	6.8
CES + Offshore Wind	-9.9	11.4	19.6	1.2	8.0	3.0

* New solar capacity excludes required installations under HB589.

** Change in coal summer capacity shown for DIEM.

Generation Changes

Table ES.7 categorizes in-state generation into three buckets: fossil; non-emitting sources such as nuclear, hydroelectric, and renewables; and net imports. Results are also shown for 2035 to examine the generation mix in the state at that juncture.

Policy Highlights

- By 2035, **baseline** in-state generation is 56% non-emitting in IPM and 71% non-emitting in DIEM. These responses affected the different emissions and cost outcomes shown previously between the two models.

- **Accelerated coal retirements** and **RGGI** do not lead to additional generation by renewables in the state. In IPM, most of the reduced coal generation from these policies is replaced by imports. Coal retirements have minor impacts on renewables in DIEM.
- The **CES stand-alone** and **CES combination** options lead to similar levels of in-state non-emitting generation. Differences across the CES options are largely in the mix of in-state fossil generation versus imported electricity.
- Even by 2050, **CES policies** have fairly limited effects on in-state fossil generation compared to “business as usual,” except for options that combine the CES with a carbon adder on generation.⁶ This is because fossil units can still generate power for export.
- **CES policies** lead to lower levels of net imports, or in later years net exports (shown as negative net imports), than other policies. A CES policy that enabled the use of out-of-state credits (not modeled in this report) would change this outcome.

Table ES.7. NC Generation in IPM and DIEM (TWh)

IPM Model	2030			2035			2040			2050		
	Fossil	Non-emit	Net Import	Fossil	Non-emit	Net Import	Fossil	Non-emit	Net Import	Fossil	Non-emit	Net Import
Baseline	67	65	21	64	80	16	54	81	31	45	108	25
Accelerated Coal Retirement	56	65	33	51	80	28	50	81	34	45	109	25
RGGI with 3% decline/year to 2030	58	65	30	53	80	25	46	81	37	41	116	21
RGGI with 2030 CEP target	55	65	34	53	80	25	46	81	37	41	117	21
RGGI w/2030 CEP target & EE	54	65	31	52	80	22	46	81	34	41	115	21
CO2 Adder on New Capacity	63	65	25	60	80	19	46	81	38	39	120	20
CES on NC Retail Sales	57	99	-1	51	111	-3	40	125	2	35	154	-9
CES + Coal Retirement	46	99	9	42	111	6	38	125	4	35	154	-9
CES + RGGI	49	99	6	42	111	5	37	125	3	31	154	-6
CES + RGGI + Offshore Wind	48	99	7	42	111	5	38	132	-6	29	154	-5
CES + CO2 Adder on New Capacity	57	99	-2	51	111	-2	40	125	2	33	154	-7
CES + CO2 Adder on Generation	39	99	14	29	111	18	24	125	16	6	158	15
CES + Offshore Wind	56	99	-1	52	111	-4	41	132	-8	32	154	-8
DIEM Model	2030			2035			2040			2050		
	Fossil	Non-emit	Net Import	Fossil	Non-emit	Net Import	Fossil	Non-emit	Net Import	Fossil	Non-emit	Net Import
Baseline	59	73	20	39	94	26	34	100	32	31	114	35
Accelerated Coal Retirement	56	73	23	34	96	29	33	100	33	31	114	35
CO2 Adder on New Capacity	57	73	22	35	101	24	30	119	19	26	142	16
CO2 Adder on Generation	35	78	40	25	97	38	14	104	50	3	121	57
CO2 Adder on Gen w/import adjust	36	83	33	26	110	23	19	129	21	7	155	21
CO2 Adder on Gen - USA wide	40	84	28	29	99	31	13	117	38	6	131	45
CES on NC Retail Sales	46	98	8	36	111	12	32	125	10	26	156	-2
CES on USA-wide Retail Sales	31	96	26	1	138	26	1	141	25	0	157	30
CES + Coal Retirement	43	98	10	33	111	15	30	125	11	26	156	-2
CES + CO2 Adder on New Capacity	46	98	9	34	111	14	29	129	10	24	156	2
CES + CO2 Adder on Generation	29	98	26	22	111	27	12	125	31	2	156	24
CES + Offshore Wind	43	98	10	36	111	11	29	136	6	27	156	-3

6. A similar outcome could be expected by combining the CES with a RGGI program that increased in stringency after 2030.

Sensitivities

Modeling results may be highly dependent on specific assumptions. Sensitivity analyses were conducted, largely in DIEM, to test for this using the following key variables: electricity demand, natural gas prices, renewables costs, and battery storage effectiveness. The analyses were conducted on one “push” policy—a carbon adder on generation—and one “pull” policy—a CES. Table ES.8 looks at how policy costs, emissions reductions in 2030, and capacity changes by 2040 can vary across assumptions in DIEM (looking at capacity differences in 2040 helps highlight how variables influence policy results better than those for 2030 when data differences may not have had enough time to alter the results). Policy cost results are shown under a 20-year and a 30-year payback schedule for renewables.

Assumptions about Electricity Demand Growth

The standard electricity growth assumption for most modeling came from the DEC/DEP 2020 IRP, which projects demand growth of around 0.6% per year, after accounting for EE and demand-side management (“**IRP**” in Table ES.8). Sensitivities were run using US Energy Information Administration forecasts that grow at around 1% and 1.3% per year in the Carolinas region (“**AEO Reference**” versus “**AEO High Macro**”). Another alternative looked at the potential for increased demand from electric vehicles, based on NREL’s **Medium EV** forecast. Other demand projections are run as well (see **Appendix F**), assuming more ambitious uptake of EE measures (resulting in lower demand and the potential use of EE as a CES compliance mechanism). However, as noted in the EE call-out box, it is challenging to evaluate the full potential benefits of EE measures without the availability of a “supply curve” for EE that shows the quantity of EE savings available for a range of costs in the state of North Carolina.

Assumptions about Natural Gas Prices

Standard baseline assumptions about natural gas prices (“**ICF+AEO**”) come from ICF gas modeling, transitioning to AEO forecasts after eight years (see **Appendix B** for a chart with these results). These prices start at around \$2.50/MMBtu and rise to around \$3.25/MMBtu after 2030. Sensitivity cases reported in Table ES.⁸ assume gas prices that are around \$1/MMBtu higher in all years (“**AEO Reference**”); there are also DIEM results assuming that gas prices remain flat at roughly today’s levels in all future years (“**Flat at \$2.50**”). Finally, it was assumed in most model runs that new combined cycle units face an additional \$1.5/MMBtu fixed charge to secure access to firm gas contracts—this assumption is removed in the “**No +\$1.50 on new CC**” results.

Assumptions about Renewables and Batteries

There was significant discussion among stakeholders about assumptions to use for renewables costs (and the related issue of battery effectiveness at meeting peak load). Standard modeling assumptions took a more conservative view of renewables. Then, sensitivities were run to demonstrate how more favorable—but still reasonable—outlooks could either enhance or decrease the cost-effectiveness of clean energy policies.⁷

While the “standard” runs in this report relied on NREL’s “**Moderate**” forecasts for future solar PV, wind, and battery costs, other runs used NREL’s “**Advanced**” forecast featuring more

7. In spite of the discussion, no consensus was reached regarding likely trends for renewables and batteries.

optimistic results for these cost trends. Also, standard assumptions about battery effectiveness and the amount that the DEC/DEP system can support come from an **Astrape Consulting** report that was part of the DEC/DEP 2020 IRP.⁸ Given the uncertainty about the amount of battery storage that systems can support and the cost of batteries, these assumptions are contrasted to runs in which batteries are 100% effective at meeting peak demand needs in North Carolina (“**100% Credit**”) and runs in which an additional 15% cost adder is applied to the NREL Moderate Case battery cost assumptions to proxy additional costs associated with depth-of-discharge concerns for batteries that cycle on a daily basis (“**+15% DoD Cost**”).

Highlights of the sensitivity analyses:

- Across the sensitivities, policy costs using a 30-year book life are 20%–45% lower than for an assumption of a 20-year book life for renewables. (Recall that when all of the standard assumptions were used except for book life, some costs dropped 64%).
- Policy costs do not vary dramatically across assumptions about electricity demand (note that these are changes in costs relative to the baseline—total costs will be higher when there is additional electricity demand; adding the policies on top of a higher baseline demand is, however, not dramatically changing their costs).
- Higher gas prices in the “AEO Reference” runs lead to higher policy costs in the carbon adder case since the combination of the higher gas prices and price on the carbon content of gas mean that additional (and more costly) renewables are installed to avoid using gas.
- Conversely, higher gas prices under the CES policy are associated with lower policy costs since both the CES and the higher gas prices act to encourage renewables.
- The \$1.50/MMBtu adder that proxies a premium for securing firm gas capacity for new combined cycle units makes these types of units uneconomic. If these additional costs are not incurred, combined cycles will be built—particularly under a CES.
- The lower renewable costs associated with the NREL Advanced forecasts lead to lower policy costs, regardless of the type of policy.
- Emissions in 2030 under the CES policy remain around the 70% reduction point across most sensitivities, with the exceptions of high gas prices (which cause coal units to run instead of gas units) and low renewables costs (where the CES and renewables costs move emissions in the same direction and lead to additional reductions).
- In either the carbon adder or CES cases, the Astrape battery assumptions limiting the contribution of batteries to peak demands lead to far lower battery installations than the assumption that batteries would contribute 100% of their capacity towards meeting peaks.
- Conversely, higher battery prices from an additional 15% cost to proxy depth-of-discharge concerns for daily cycling would lower battery installations by around 30–60%.

8. DIEM used data from Attachment IV to the IRP, while IPM used data from the body of the IRP.

Table ES.8. Sensitivity Analyses in DIEM

Policy Case	Renewables booklife: 20-year 30-year		NPV to 2050 (\$ billion)	NPV to 2050 (\$ billion)	CO2 % reduced from 2005 in 2030 (w/imports)	Capacity Change by 2040 (GW)				
	Variable	Sensitivity				Combined Cycle	Gas Turbines	Solar PV	Wind	Battery Storage
CO2 Adder (\$6/ton+7%/year)	Electricity Demand Growth	IRP	\$2.9	\$2.2	75%		5.7	17.5	2.2	2.3
		AEO Reference	\$3.1	\$2.1	73%		5.5	23.4	2.8	2.1
		AEO High Macro	\$3.2	\$1.9	72%		6.4	27.8	2.8	1.9
		NREL Medium EV	\$3.7	\$9.4	71%		0.9	33.5	2.9	1.6
	Natural Gas Prices	ICF+AEO	\$2.9	\$2.2	75%		5.7	17.5	2.2	2.3
		AEO Reference	\$4.8	\$3.3	85%		4.1	27.0	3.5	4.2
		Flat at \$2.5	\$2.5	\$1.7	71%		7.3	15.0	0.3	
		No +\$1.5 on new CC	\$4.1	\$3.2	75%	0.7	7.9	16.7	1.0	1.8
	Renewables Costs	NREL Moderate	\$2.9	\$2.2	75%		5.7	17.5	2.2	2.3
		NREL Advanced	\$1.1	\$0.8	95%		0.1	30.4	0.1	2.4
	Battery Storage	Astrape	\$2.9	\$2.2	75%		5.7	17.5	2.2	2.3
		100% Credit	\$4.1	\$2.2	75%		0.8	21.8	1.8	9.9
	Assumptions	+15% DoD Cost	\$2.4	\$2.0	75%		7.4	14.9	2.2	0.7
CES (70% in 2030, 95% in 2050)	Electricity Demand Growth	IRP	\$3.8	\$2.2	70%		7.9	24.6	2.7	0.6
		AEO Reference	\$3.9	\$2.2	69%		8.2	26.2	2.8	0.6
		AEO High Macro	\$4.1	\$2.4	68%		9.9	29.9	2.9	1.4
		NREL Medium EV	\$12.1	\$9.5	68%		6.0	31.3	3.6	1.4
	Natural Gas Prices	ICF+AEO	\$3.8	\$2.2	70%		7.9	24.6	2.7	0.6
		AEO Reference	\$1.4	\$0.7	62%		4.4	27.3	2.8	3.2
		Flat at \$2.5	\$5.6	\$3.2	71%		9.3	24.3	2.3	
		No +\$1.5 on new CC	\$5.7	\$3.6	77%	5.7	6.3	25.1	1.7	0.2
	Renewables Costs	NREL Moderate	\$3.8	\$2.2	70%		7.9	24.6	2.7	0.6
		NREL Advanced	\$1.0	\$0.8	88%			29.1	0.3	3.1
	Battery Storage	Astrape	\$3.8	\$2.2	70%		7.9	24.6	2.7	0.6
		100% Credit	\$3.8	\$2.1	70%		5.8	24.2	2.3	4.4
	Assumptions	+15% DoD Cost	\$3.7	\$2.2	70%		8.8	23.4	2.9	0.3

Note: Results for “standard” assumptions are shown in bold (and are the same across the bolded cases).

Incorporating Energy Efficiency into Modeling

Energy efficiency (EE) is widely considered a low-cost way to reduce energy use by upgrading technologies or encouraging behavioral changes behind the meter. EE investments can lower electricity demand over time, delaying or reducing the need for new, more costly, and possibly emitting units. However, different EE strategies vary in cost-effectiveness, and provide distinct non-energy benefits to the system.

North Carolina does not have state-specific cost performance data that could be used to evaluate the relative costs of EE programs or compare costs and system benefits of EE options.¹ Absent a so-called “EE cost curve,” this report uses reductions in energy demand to approximate the impact of EE with reductions in energy demand. The report studies EE in three ways:

Standard Assumptions – This case uses electricity demand growth rates, energy efficiency, and demand-side management assumptions from the DEC/DEP IRPs.

“Medium” Energy Efficiency – This case assumes that EE measures result in a 1% decline in demand per year through 2030,

taper to 0.5% by 2040, and persist at that level to 2050.

“High” Energy Efficiency – This case assumes that EE measures result in a 1–2% decline in demand per year through 2030, taper to 1.0% by 2040, and persist at that level to 2050.

In IPM, EE investments from RGGI auction revenue are analyzed for their ability to reduce load and moderate bill and rate impacts (Section 7, pages 120–123).

In IPM, the “Medium” and “High” EE cases are used for CES compliance to approximate the impact of an Energy Efficiency Resource Standard (EERS) (**Appendix F**, Figs. F.16 & F.17.).

In DIEM, three EE cases are used to study the impact of load assumptions on two policies: a carbon adder on generation and a CES (**Appendix F**, Figs. 48–53).

The approaches can be used to understand the directional impacts of EE investment. But to truly understand the costs and benefits of EE, analysis must be done with a state-specific cost curve.

1. For more on the use of EE cost curves, please see “The Cost of Saving Electricity: A Multi-Program Cost Curve for Programs Funded by U.S. Utility Customers,” Goldman, C.A., et. al, Lawrence Berkeley National Laboratory (LBNL), Berkeley, CA, USA, April 2020. https://eta-publications.lbl.gov/sites/default/files/manuscript.v9_nmf.pdf.

Rate/Bill Changes, and Macroeconomic Impacts

ICF studied some economic impacts of the following subset of carbon policies:

- (1) A number of RGGI scenarios;
- (2) The standard modeled CES (70% clean in 2030; 95% clean in 2050);
- (3) The CES combined with the standard accelerated coal retirements policy; and
- (4) The CES combined with different RGGI scenarios.

This part of the analysis considers how policy makers could use revenues generated from a RGGI CO₂ allowance auction to lower program costs to ratepayers. Table ES.9 presents the projected revenues from a RGGI auction—nearly \$1 billion from 2023 to 2030.

Table ES.9. Projected RGGI Auction Revenues

Year	2023	2024	2025	2026	2027	2028	2029	2030	Cumulative, 2023–2030
Allowance Revenue (2012\$)	140 m	139 m	139 m	139 m	113 m	113 m	90 m	90 m	963 m

ICF studied three possible outcomes of a RGGI auction—one where revenues are not recycled back into the power sector but used on other state budget priorities (“no revenue recycling”); another where proceeds are invested in EE; and finally, one where proceeds are given back to all residential ratepayers (or just low-income ratepayers) in a direct bill assistance program. If DEQ decided to freely allocate CO₂ allowances, the Utilities Commission would likely act to ensure that the value of the allowances flows through to the ratepayers. That suggests the direct bill assistance scenarios best approximate a free allocation regime, although the Utilities Commission might want to benefit all customer classes.

Across all four of the policy scenarios subjected to rate/bill analysis, ICF allocated costs to the three customer classes based on their current share of North Carolina electricity demand: 42% to residential; 38% to commercial; and 19% to industrial users. ICF then calculated the percentage change a policy caused to average monthly residential bills and retail rates for commercial and industrial customers. ICF did not translate commercial and industrial rate impacts into bills because an average bill would not tend to be representative for those sectors.

Table ES.10 presents the changes to electricity rates and bills in 2030 compared to projections under “business as usual.” This is just a snapshot in time. ***By 2043, all climate policies result in lower monthly residential bills than the baseline***—in part because of a stronger shift into renewables which have no fuel costs. (The average residential household bill was projected to be \$170.41 under business as usual in 2030.) By 2048, all climate policies result in lower rates than in the baseline for all customer classes.⁹ Note that the standard policy modeling was used here; alternative scenarios for renewables costs would reduce all of these costs.

9. Section 7 of the report provides more detail on the cost impacts of the policies and their economic effect.

**Table ES.10. Summary of Projected Bill and Rate Impacts in 2030, by Scenario
(Expressed in Change over Baseline Cases)**

Customer Class	RGGI No Revenue Recycling (RR)	RGGI Auction – direct bill assistance (DBA)*	RGGI Auction – EE investment	CES	CES + Coal Retirement	CES + RGGI (no RR)	CES + RGGI (DBA)	CES + RGGI (EE)
Residential (per month)	\$1.44 (0.8%)	-\$0.65 (-0.4%)	\$0.65 (0.4%)	\$2.34 (1.4%)	\$2.51 (15%)	\$2.92 (17%)	\$0.83 (0.5%)	\$2.25 (1.3%)
Commercial (cents/kwh)	.13 (1.1%)	.13 (1.1%)	.06 (0.5%)	.21 (1.9%)	.22 (2.0%)	.26 (2.3%)	.26 (2.3%)	.20 (1.8%)
Industrial (cents/kwh)	.10 (1.5%)	.10 (1.5%)	.04 (0.7%)	.16 (2.4%)	.17 (2.6%)	.19 (3.0%)	.19 (3.0%)	.15 (2.3%)

* ICF also ran a scenario where direct bill assistance was only provided to low-income households (those earning up to the federal poverty level). In 2030, that policy would result in a \$15.17 decrease in low-income monthly electricity bills (-8.9%), and an increase for other households of \$1.44 per month (0.8%).

Table ES.11 summarizes the cumulative job and Gross State Product (GSP) impacts of the studied policies. The analyzed policies analyzed have a relatively small effect on North Carolina’s economy, changing the jobs outlook -0.01% to +0.05% from “business as usual” job projections, and GSP levels -0.01% to +0.03%.

Table ES.11 Summary of Cumulative Job and GSP Impacts Across Scenarios

(2023–2050)	Cumulative Job Impacts		Cumulative GSP Impacts	
Scenario	Job-years	% Change from baseline	GSP 2020\$ (millions)	% Change from baseline
1a: RGGI Load Adjusted Energy Efficiency	47,337	0.03%	4,868	0.02%
1b: RGGI Direct Bill Assistance (Using REMI allocation across income groups)	-11,228	-0.01%	-1,581	-0.01%
1c: RGGI Direct Bill Assistance (Focusing on low-income groups)	-10,901	-0.01%	-1,398	-0.01%
2: Stand-alone CES	37,275	0.02%	2,869	0.01%

(2023–2050)	Cumulative Job Impacts		Cumulative GSP Impacts	
Scenario	Job-years	% Change from baseline	GSP 2020\$ (millions)	% Change from baseline
3: CES + Coal Retirement	25,376	0.01%	1,110	0.00%
4a: CES + RGGI (no revenue recycling)	17,777	0.01%	348	0.00%
4b: CES + RGGI (revenue recycling)	89,998	0.05%	7,885	0.03%

By 2033, a RGGI program with auction revenues invested in EE reduces rates/bills in all three customer classes below business as usual. This policy results in the lowest cost for commercial and industrial customers for any policy through lower demand projections. It also drives the most job creation of any of the stand-alone policies. Directing RGGI proceeds to bill assistance for residential households¹⁰ results in the lowest residential bills of any policy but somewhat higher commercial and industrial rates (see Table ES.10) and lackluster jobs and GSP impacts. Targeting families earning up to the federal poverty level for bill assistance shifted the distribution of savings across residential bills but had no effect on the macroeconomic effect.

By the late 2020s, a CES, alone or combined with other policies, is increasing in compliance costs but also driving more clean energy job growth. The CES becomes relatively more expensive than other policies for ratepayers in the 2030s, but the higher percentage of fuel-free generation, coupled with electricity sales to other states, results in lower rates/bills for this policy starting in the 2040s than the other policies studied for rate and bills impacts.

A CES combined with RGGI leads to the largest cumulative increases in electric bills and rates. However, this upward rate pressure is moderated where RGGI proceeds are invested in EE. Moreover, this combination drives deep CO₂ reductions between now and 2050, resulting in a lower dollar-per-ton cost than a stand-alone CES (Table ES.4). This combination also creates the most jobs and positive economic activity across all studied policies—a cumulative 90,000 job-years, nearly twice that of a stand-alone RGGI program with EE investment.

10. If North Carolina were to freely allocate allowances, the Utilities Commission would likely require utilities to pass through the value of the allowances to customers. The residential “direct bill assistance” scenarios described here would be the most analogous to that situation, although the Utilities Commission might require the savings to flow to all customer classes. Similarly, if North Carolina were to require utilities to consign allowances to an auction, proceeds would also likely be required to pass through in the form of customer savings.

Conclusion

North Carolina has options for meeting the CO₂ reduction targets in the CEP. Given the rapid shifts occurring on the grid and the convergence of cost between types of electricity generation, even modest policies could drive large changes in the North Carolina power sector, with positive emissions and economic impacts.

The policy pathways described in this report could influence the state's installed capacity or the electricity generation mix that serves North Carolinians. They might also affect the cost of electricity, levels of air pollution, and the jobs and economic outlook for the state in different ways. This report does not recommend a single path forward but offers options for action and a number of ways to compare policies and policy combinations, to inform the design of effective, affordable, and equitable emissions reduction policies for this sector.