



State Policy Options to Price Carbon from Electricity

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Executive Summary

Thirteen states have (or are on the verge having) carbon pricing implemented as cap and trade. This report describes the opportunity for the expansion of carbon pricing in the electricity sector to six new states. We consider the introduction of cap and trade, borrowing the architecture of the Regional Greenhouse Gas Initiative (RGGI) and introducing it in each venue.

A combination of changing electricity market trends, the opportunities of clean energy technology, and the environmental and economic impacts of climate change have motivated states to provide an impetus for reducing greenhouse gas emissions and encouraging clean energy development. States are looking at policies that work for their own state including pricing carbon and regulatory support for clean technology development, and they are looking at opportunities to collaborate with other states to amplify the impact of their actions.

We separately investigate North Carolina and Pennsylvania, which are contiguous to the RGGI states and thus are potential electricity trading partners, as well as a group of four upper Midwest states: Minnesota, Wisconsin, Illinois, and Michigan. In each case, we imagine the states adopt all elements of RGGI added or preserved in the most recent program review in 2016. This includes the emissions budgets (caps) that take effect in 2021 and are set based on an annual reduction through 2030 of 3 percent of each state's 2020 emissions as forecast in the model. We examine several approaches to cap and trade that are distinguished by how allowance value (auction proceeds) is used and whether a new state program is linked with the RGGI program. We also consider policies promoting renewable technologies. We examine these policies using a detailed electricity sector model called Haiku. We focus attention on results for 2026 to capture outcomes that could be expected in the current policy window and prior to the emergence of other trends such as technology change and national policy that might begin to depart from the model assumptions.

The cost of achieving these levels of emissions reductions is small, as measured by the price of emissions allowances and, where possible, by the change in electricity prices. In most cases, the allowance price is low enough to trigger the emissions containment reserve, a feature that withholds up to 10 percent of the total number of allowances offered for sale at each auction from being sold if the auction-clearing allowance price falls at or below a specified price trigger (\$6.80 in real 2015\$). In many cases, the allowance price rests on the price floor (\$2.05 in real 2015\$), which is the minimum price at which allowances will enter the market. When either of these cost management features is triggered, the volume of allowances that are issued is less than the nominal cap, which declines by 3 percent of 2020 emissions each year, and emissions reductions are achieved at an accelerated rate.

The baseline is becoming cleaner over the next decade and accounts for reductions of almost 3 percent compared to constant-level 2020 emissions throughout the decade. The nominal carbon cap falls by 3 percent of 2020 emissions levels per year (30 percent by 2030) and would reduce cumulative emissions by 15 percent over the decade. The emissions reductions that are achieved vary slightly across scenarios. A relatively modest assessment is represented by the scenario with no linking (linking would contribute modest additional emissions reductions due to cost management features described in the report) and allowance value directed to the general fund (some investments, such as energy efficiency, would yield further emissions reductions). This scenario leads to cumulative emissions reductions in the six states relative to constant-level 2020 emissions of 974 million tons, or almost 25 percent, which is nearly 10 percent greater than required by the nominal emissions target. Emissions reductions beyond what is required by the emissions target are achieved because cost management features in the program design further limit emissions when allowance prices are low. The low costs and low allowance prices of achieving the emissions caps suggest more ambition is plausible without incurring substantial cost.

Our evaluation of carbon pricing alongside policies that promote renewable technologies suggests that renewable technology policies can be successful in achieving greater investment in renewable capacity and greater renewable generation. However, renewable technology policies achieve fewer emissions reductions in the next decade at higher cost than carbon pricing. Carbon pricing achieves greater emissions reduction at less cost because it fully accounts for the cost of emissions from coal plants and differentiates among coal and gas facilities according to their emissions. In contrast, the renewable technology policy does not differentiate between the coal and gas facilities that renewables displace. A policymaker might view technology policies as useful to develop a strong clean-generation infrastructure and to provide opportunities to learn about grid integration of renewables, which will enable the state to achieve greater emissions reductions in the long run. Both approaches contribute to emissions reductions and renewables deployment, and a combination of approaches is possible.









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Under any of the approaches to initially distributing emissions allowances that we model, the state's emission cap is achieved, as indicated in column 1 of Table ES-1. Increased emissions from generators inside and outside the state that are not subject to a carbon price may partially erode the emissions reductions—the phenomenon known as “leakage”—though never dwarfing the benefits of the program. Investments in energy efficiency often helps to reduce this problem, and

so does linking programs to create a larger market. Another potent remedy is free allowance allocation to generators based on their share of generation—known as “output-based allocation.” This allocation approach provides an incentive for in-state production that will be covered by the emissions cap. Capping emissions associated with imported power is another available method to reduce leakage that was not modeled, and which has been used in other jurisdictions.

The allowance prices and associated changes in electricity prices are expected to be generally small in all cases considered here. Allowance allocation to support expenditures for energy efficiency and rate relief through local distribution companies serve to further protect consumers and reduce energy bills compared to scenarios with no allocation and funds returned to the general fund, as illustrated by the third column of Table ES-1. Investments in energy efficiency also create jobs and promote economic development. Output-based allocation also tends to reduce electricity prices. However, no allocation preserves auction proceeds that might be used for other purposes.

Table ES-1. Allowance Allocation and Environmental and Consumer Impacts

	Reduce State Emissions	Reduce National Emissions	Protect Consumers
No Allowance Allocation (Proceeds go to the General Fund)			
Allocation to Energy Efficiency / Rate Relief			
Updating Output-Based Allocation			

Note: Any cap-and-trade program can effectively reduce state emissions, regardless of allowance allocation. No allocation (proceeds directed to the general fund) preserves auction proceeds for expenditure on other priorities, such as adaptation. An allocation to energy efficiency or to electricity rate relief via local distribution companies can protect consumers from higher costs brought about by a program. Updating output-based allocation creates a local generation subsidy that simultaneously protects consumers and reduces leakage, i.e. enhances national emissions reductions.

One reason the cost of achieving these emissions reductions appears inexpensive is that the baseline is becoming cleaner over time. Against this backdrop, the emissions cap ensures an environmental outcome and prevents backsliding. Carbon pricing makes allowance proceeds available, and states could consider a variety of spending priorities to promote their goals.

Because allowance prices are similarly low in the trading programs in RGGI and in the other modeled states, linking of the programs does not result in a dramatic flow of allowances or change in allowance prices. However, linking promises other benefits that can make it an attractive choice for states that are launching a carbon-pricing policy. For one, linking makes the state's program resilient to uncertain events that affect electricity markets, such as unexpected changes in weather or economic activity. Linking also reduces uncertainty by limiting fluctuations in allowance prices, thus making compliance planning less costly for regulated utilities. Linking also could help bolster the influence states can have in shaping a national policy. In general, linking is made easier both administratively and politically when programs have similar design elements as we have modeled here.

*The baseline is becoming cleaner over time.
Against this backdrop, the emissions cap ensures
an environmental outcome and prevents
backsliding.*

Introduction

A combination of changing electricity market trends, the opportunities of clean energy technology, and the environmental and economic impacts of climate change have motivated states to provide an impetus for reducing greenhouse gas emissions and encouraging clean energy development. Twenty-two states and the District of Columbia have greenhouse gas emissions targets.¹ Twenty-three states and Puerto Rico have joined the Climate Alliance, committing to advance the goals of the Paris Agreement, track and report their progress, and accelerate emissions mitigation policies. In the transportation sector, states have deployed standards to promote low-carbon fuels, vehicle efficiency standards, and zero-emissions vehicle mandates. Policies to promote electricity generation by renewable sources have been implemented in 29 states and the District of Columbia,² and energy efficiency policies including quantitative targets have been mandated by 24 states. Currently, 13 states have (or are on the verge of having) carbon pricing implemented as cap-and-trade programs.

States are eager to understand policy options for reducing their carbon emissions, and much attention focuses on the electricity sector as a place to start. This focus stems from existing technology options such as wind and solar for producing electricity without carbon and from the opportunities for decarbonizing other sectors by switching away from fossil fuels to electricity once that electricity is produced more cleanly. Existing policies in the electricity sector are often focused on technology, such as Renewable Portfolio Standards (RPS) that require utilities to generate or purchase a share of their load from renewables, and on pricing carbon directly. States want to understand how effective and how costly the different policy options are, how they affect electricity producers and consumers, and their impact on interstate power trading in the regional market.

Ten Northeast and Mid-Atlantic states began pricing carbon emissions in the electricity sector in 2009 through the formation of the Regional Greenhouse Gas Initiative (RGGI).³ States in the region have diverse energy use profiles and power generation resource mixes, regulations, and market structures. RGGI has demonstrated the durability of a state-level approach to carbon trading and a collaborative state process for decisionmaking. The program has completed two program reviews culminating in strengthened program design and increased stringency.

This report examines the introduction of an electricity-sector cap-and-trade policy in additional states with the option to link to existing regional programs, such as RGGI. We examine two states that are contiguous to RGGI, North Carolina and Pennsylvania, and four states from the upper Midwest, Minnesota, Wisconsin, Illinois, and Michigan. These states were identified without solicitation of interest from the states, and the research has been conducted independently. They all are members

of the Climate Alliance⁴, and recent executive actions in these states suggest they are exploring carbon mitigation strategies. Using detailed modeling of the electricity sector, we examine possible outcomes of go-it-alone state cap-and-trade policies, regional coalitions, and potential linking with the existing RGGI program. We also consider other policy options to promote clean energy technologies and the potential interaction of these policies with cap and trade. We describe how different policies affect the mix of technologies and fuels used to supply electricity in a state, power trading between states, prices paid by consumers, and carbon emissions.

To analyze these issues, we use a new version of a detailed electricity sector market model named Haiku that has been used in two dozen previous reports and scholarly publications. The model identifies state-level electricity market equilibria for the continental United States for three seasons and four time blocks, with capacity investment and retirement over a 25-year horizon. Electricity demand is price responsive. The model has careful representation of relevant national and state-level electricity sector policies, and can represent alternative distributions of emissions allowances under cap and trade and the effect of those distributions on overall outcomes.

In brief, we find the introduction of an emissions cap that declines annually at 3 percent of 2020 emissions yields low allowance prices, usually at or below the emissions containment reserve price trigger (explained later) and sometimes at the price floor, thereby yielding emissions reductions greater than 3 percent per year. Even where the baseline (without carbon pricing) has declining emissions over time, the emissions cap ensures an environmental outcome and prevents the possibility of backsliding. Carbon pricing makes allowance proceeds available, and states could consider a mix of spending priorities to promote their energy goals. We find a portion of the emissions reductions achieved in a state can emerge as emissions increases in other jurisdictions (i.e. “leakage”), but elements of program design including linking, investment in energy efficiency and, in particular, the strategic use of allowance proceeds to provide incentives for in-state generation or energy efficiency can mitigate that outcome. Energy efficiency spending has other benefits including job creation and local economic development that are not considered in this analysis (Hibbard et al. 2018). Capping emissions associated with imported power is another method to reduce leakage that was not modeled but has been applied in other jurisdictions.

Because allowance prices are similarly low in the new states and in RGGI when key program elements are the same (i.e. same declining cap and cost control mechanisms), linking of the programs has little effect on prices and results in little flow of allowances between the programs. However, as we discuss below, linking promises other benefits that are not a part of this study, including resilience to uncertain potential developments in electricity markets. We also evaluate carbon pricing alongside technology policies that promote low- and non-emitting technologies and find that technology policies are indeed successful in achieving

greater renewable generation capacity but achieve fewer emissions reductions in the next decade and at higher cost than carbon pricing because they do not provide an incentive for substitution to natural gas generation from coal. A policymaker might view technology policies as useful to develop a strong clean-generation infrastructure including grid integration of renewables, which will enable the state to achieve greater emissions reductions in the long run. But both approaches contribute to both outcomes, and a combination of approaches is possible.

We begin with background on state-level cap-and-trade for the electricity sector. We then describe a business-as-usual baseline and various policy scenarios as they are represented in the model. We provide a brief introduction to the model and results, starting with a summary, and then consider potential policies in states neighboring the RGGI region and in the Midwest states. The appendix contains a literature review.

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Background

The design of state-level carbon dioxide (CO₂) cap-and-trade policy is fundamentally straightforward, but implementation can involve trade-offs affecting the costs to industry and electricity consumers, as well as interactions with companion policies to promote clean energy and energy efficiency and with regional electricity markets.

The emissions limit (i.e., the level of the cap) is the primary feature of cap and trade. However, vitally important to the program's cost and distributional impacts is how emissions allowances are initially distributed. Before RGGI, existing cap-and-trade programs, including the federal sulfur dioxide (SO₂) cap-and-trade program in the electricity sector under Title IV of the Clean Air Act Amendments of 1990, distributed allowances at zero cost to emitting generators based on a generating unit's historic heat input (which is closely related to its generation). Until the 1990s, the electricity industry was exclusively a cost-of-service regulated industry, meaning that prices were based on incurred costs. Through free allocation, the incurred cost of allowances is zero, so the potential effect on the price of electricity is suppressed. Firms nonetheless retain an incentive to reduce emissions as long as they have an incentive to minimize overall costs; however, consumers do not receive a signal in the form of higher prices that might lead them to make more energy-efficient decisions.

In the late 1990s, the patchwork introduction of competition to the electricity sector in roughly one-third of the country, including the states in the RGGI region, changed this dynamic. In competitive markets, generators are expected to incorporate the opportunity cost (i.e., market price) of allowances used to cover their emissions in their bids into competitive wholesale energy markets, whether those allowances were obtained for free or at a cost. Therefore, the opportunity cost of using an allowance to generate electricity would be reflected in electricity prices paid by consumers even under free allocation. This new dynamic led the states to decide to initially distribute allowances using an auction that would provide revenue that could be put toward other public purposes. The decision to auction in RGGI and its allowance auction design have influenced other cap-and-trade programs.

The decision by Virginia to develop a trade-ready regulation with an emissions cap made the issue of how best to allocate emissions allowances in a cost-of-service region newly relevant. Unlike the rest of RGGI, Virginia has a regulated electricity market and saw free allocation of allowances to emitting generators as a way to reduce the costs of this new regulation to electricity customers.⁵ However, Virginia's decision to adopt the RGGI program architecture in preparation for a possible link with the RGGI program prompted it to adopt cost containment features of the RGGI model rule that are implemented through the auction.⁶ Consequently, Virginia's program design chose to allocate allowances for free on a conditional basis; firms

cannot use the free allowances for compliance but are required to consign them for sale in the auction, with the revenues to flow back to the generators. Meanwhile, firms can buy back allowances in the same auction, but as part of that decision, one can expect that firms will be careful to minimize their costs. After approval of a final regulation that would link Virginia with RGGI in 2020, the state Assembly recently blocked funding for the linking this budget year. These model results assume Virginia linked with RGGI according to the intent of the final regulation, and thus illustrate the effects of broader state trading participation with Virginia as part of RGGI.

All the carbon cap-and-trade programs in North America and Europe coexist with companion policies that promote renewable energy and energy efficiency. These companion programs indirectly affect emissions from the sources that are directly regulated under cap and trade. Consequently, they reduce the demand for emissions allowances, which pushes down the allowance price. As cap and trade typically fits into an overarching energy and climate framework for a jurisdiction, planners must decide how to weight these programs. Greater emphasis on cap and trade is expected to be more cost-effective and can have distributional effects including on competitiveness of businesses in the state. Greater emphasis on technology policies will favor those technologies and lead to lower allowance prices by raising the price of renewable energy credits. It will not necessarily find the least-cost way to achieve emissions reduction goals. To inform this trade-off, we complement our analysis of cap and trade with a look at the interaction between carbon markets and companion state technology policies.

An issue that confronts all subnational efforts to cap carbon emissions is the extent to which emissions decreases in one jurisdiction may be offset through increased power imports and an emissions increase elsewhere in the power market. All the existing cap-and-trade programs regularly monitor the possibility that emissions reductions from sources covered by the programs could be partially eroded by emissions increases from unregulated sources in other jurisdictions, an outcome termed “emissions leakage,” and although it is generally not possible to eliminate all leakage, they find that leakage is not a major flaw (Musgrove et al. 2017). For example, the increase in generation outside RGGI is nearly offset by the reduction in emissions intensity outside the region (Regional Greenhouse Gas Initiative 2018), and a similar outcome applies to California’s program. If there is emissions leakage, the implication is that emissions reductions are less than intended but the other benefits of the trading program are unaffected (Hibbard et al. 2018). At the low allowance costs observed in existing markets, the programs remain highly cost-effective when compared with various measures of the social cost of carbon emissions. The estimate of leakage in our model may exaggerate actual outcomes in cost-of-service states, especially North Carolina because the state is not part of an organized electricity market. Nonetheless, program design offers several approaches to address leakage. For example, we examine how the distribution of allowances can provide an incentive for in-state production from low- or non-

emitting resources or for investments in energy efficiency that reduce electricity demand, approaches that have been effective in other programs. Another effective approach to address leakage is to cap emissions from imported power, an approach that has been used in the Western Climate Initiative trading program.

Another way to reduce leakage and maximize the influence of a jurisdiction's efforts to regulate carbon emissions is to link with other jurisdictions. RGGI's durability provides evidence that cap and trade has contributed to emissions reductions at low cost, has promoted economic development, and has had little impact on electricity prices (Murray and Maniloff (2015), Hibbard et al. (2018)). It has attracted interest as a model from other states contemplating carbon emissions limits and has motivated research into the possibility of linking as a way to reduce leakage.

Linking is also expected to reduce costs on average, even without uncertainty, because the marginal cost of emissions reductions becomes increasingly expensive (convex functions). Hence, an expanded set of options across regions should have a lower marginal cost than the weighted average of costs in two separate regions. Furthermore, with the introduction of uncertainty in electricity demand or fuel prices, linking will reduce the variability of allowance prices on average. Potential costs savings would be even greater if linking jurisdictions were to bring different marginal costs and opportunities for emissions reductions, but such cost savings would also result in greater emissions reductions in one jurisdiction and fewer reductions in the other. The alignment of program designs across the regions brings the price and marginal costs closer to each other; in practice, experience shows that linking has occurred only when jurisdictions have roughly similar ambition and costs ex ante. Nonetheless, costs savings are likely to enable greater ambition overall across both jurisdictions. Moreover, electricity producers and consumers are already linked in geographically broad electricity markets. Linking allowance markets may benefit these markets by coordinating investments. It also provides greater reliability for business, greater allowance price and cost resilience to weather and price shocks, and increased influence of state-level policy leadership on regional and national policy outcomes. We examine some of these effects by comparing separate and linked allowance markets.

Model Baseline

We conduct this analysis with the Haiku electricity market simulation model, which solves for power market equilibria in the contiguous 48 states and the District of Columbia, accounting for state-specific characteristics of electricity demand, supply, and policies. Markets are represented by three seasons (spring and fall are combined) and four times of day, representing variation in resource availability and electricity consumption. The time blocks correspond to baseload, shoulder, peak, and superpeak hours of each season.

To identify electricity supply, Haiku solves for capacity investment and retirement in an intertemporally consistent framework that assumes perfect foresight. System operation satisfies load while maintaining a minimum capacity reserve margin in all hours. The supply side of the model begins with a bottom-up structure that aggregates capacity from an initial dataset of approximately 23,000 commercial power generators that were online in 2015, with subsequent adjustments to capacity based on state-specific information, and the model proceeds to identify further investment and retirement outcomes. Power is tradable across states and regions up to transmission constraints that characterize the national power grid and evolve according to assumptions in EIA (2017). The demand side of the model is a top-down system that characterizes changes in electricity consumption in response to changes in electricity prices. Electricity is priced at average cost in states that regulate power markets by cost of service and at marginal cost in states where wholesale power trades competitively.

The Haiku model has recently been reformulated in a state-of-the-art framework called a mixed complementarity problem (MCP).⁷ An MCP is a mathematically robust object that is more flexible than a linear program, which is the formulation that is dominant within the community of national-scale electricity models. Several characteristics of US power markets and approaches to policy design cannot be modeled in a linear program framework but are accommodated by the MCP formulation of Haiku. These include the following:

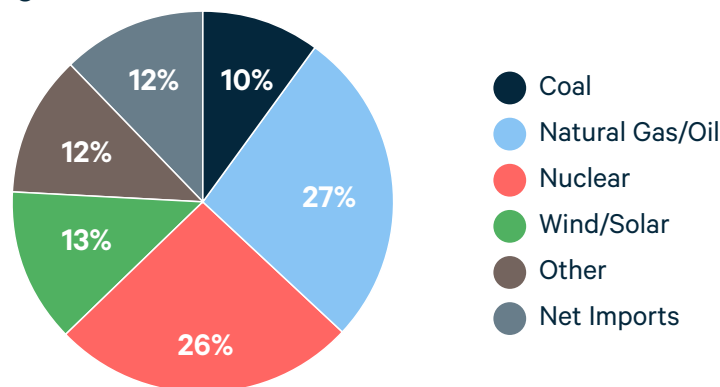
- Cost-of-service retail electricity pricing where appropriate
- Price-responsive electricity demand
- Internally consistent representation of dynamic output-based emissions allowance allocation under an emissions cap to provide incentives for generation with specific technologies
- Endogenous investments in demand-side energy efficiency
- Endogenous and internally consistent representation of features of the RGGI program design, including the cost containment reserve, the emissions containment reserve, and the price floor

We model states in the RGGI region as having competitive electricity markets⁸ except for Virginia, which is represented as a regulated electricity market. We assume New Jersey and Virginia link with RGGI in 2020, although as we note the decision in Virginia recently has been put on hold at present. North Carolina and the four states in the Midwest are represented as regulated, and Pennsylvania is modeled as competitive.

The model is calibrated to the regional output of the Electricity Market Module of the National Energy Modeling System as used for the 2017 Annual Energy Outlook (EIA 2017). Information about planned capacity investments and retirements is drawn from SNL Global and from selected state energy documents. In the RGGI states, including New Jersey and Virginia, we identify planned retirement of 164 MW of coal-fired capacity, 176 MW of oil, and 11.2 GW of nuclear capacity sometime after 2018. Investment in 2.6 GW of natural gas combined-cycle capacity is also planned. Virginia is assumed to increase energy efficiency spending by \$100 million per year from 2021 through 2030 and to build 3 GW of new solar by 2022, 3.4 GW by 2026, and cumulatively 5.2 GW by 2042, under the Grid Transformation and Security Act. We describe specific assumptions for other regions when discussing state-specific policy scenarios.

The calibration 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 are downscaled to the state level and compared with recent state-level forecasts used by the Environmental Protection Agency (2018) and information we collected from integrated resource plans and other forecasts. This comparison yields an evolving baseline. Figure 1 illustrates the electricity supply mix in the 11-state RGGI region for 2026.

Figure 1. Anticipated electricity supply by fuel in the 11-state RGGI region in 2026



The model baseline assumes elements of the RGGI 2016 Program Review (completed in 2017) are fully implemented⁹, including adjustments to the cap, adjustments to the cost containment reserve, and the introduction of the emissions containment reserve (ECR) effective in 2021. The price floor is set at \$2.05 per ton and held constant in real terms (i.e., adjusted for inflation). The emissions containment reserve applies a reserve price (minimum price) to 10 percent of the allowances in the program; below this price, the allowances will not be sold. This feature is introduced at \$6 per ton in 2021 and increases at 5 percent per year in real terms (7 percent nominal). We assume that allowances that are not sold under either the price floor or the emissions containment reserve are canceled and do not reenter the market. The cost containment reserve would introduce up to 10 percent of the regional cap as additional allowances in a given year. This feature is set at \$13 per ton in 2021 and increases at 5 percent per year (7 percent nominal). In all scenarios, we assume the cap-and-trade program covers all gas turbines but not internal combustion engines, landfill gas, or municipal solid waste.

The allocation of emissions allowances (i.e., the use of auction proceeds) in the nine states already in RGGI is assumed to continue in the future as described in Hibbard et al. (2018).¹⁰ When New Jersey joins the program, it is assumed to adopt an allocation approach mirroring that in the current RGGI states. Virginia is assumed to adopt updating output-based allocation, giving allowances for free to covered sources based on their share of electricity generation; these allowances must be consigned to the auction, and revenue from the auction is returned proportionately. The CO₂ emissions cap in the RGGI states including New Jersey and Virginia is assumed to decline by 3 percent of 2020 emissions beginning in 2021 and each year through 2030. State-level emissions budgets adjust accordingly, with associated changes in allowance proceeds.

Policy Scenarios

We consider the expansion of carbon pricing in the electricity sector in six new states through the introduction of cap and trade. We investigate North Carolina and Pennsylvania, which are contiguous to the RGGI states and thus are potential electricity trading partners, in two separate analyses. Then we consider a group of four upper Midwestern states: Minnesota, Wisconsin, Illinois and Michigan. In each case, we imagine the states adopt all elements of RGGI added or preserved in the 2016 program review and emissions budgets (caps) that take effect in 2021 and are set based on an annual reduction of 3 percent of each state's 2020 emissions as forecast in the model beginning in 2021 and continuing through 2030. The cap remains constant thereafter.¹¹

We vary the policy scenarios along three dimensions. The first is how states decide to allocate allowances or, equivalently, spend auction proceeds. We assume the cost-of-service regulated states adopt Virginia's approach, requiring freely allocated allowances to be consigned to an auction with auction proceeds returned to their original holders, so that the cost management features of the allowance auction can be implemented. We consider several allocation approaches individually, but a state may choose to implement a combination of approaches to achieve a mix of attributes that we identify. We examine the following approaches:

- No allowance allocation (No AA). This approach describes the possibility that allowances are auctioned and proceeds are directed to general revenue or returned to households as dividends (with no impact on electricity price).
- Output-based allocation (OBA). This approach distributes allowances to sources covered by the regulation, except coal, and to all nonemitting sources except existing hydro, wind, and solar. Existing nuclear plants are eligible for an allocation. The allocation shares are based on a facility's share of generation from among the set of sources eligible to receive an allocation.
- Allocation shared equally between spending on energy efficiency and retail rate relief for consumer administered through local distribution companies (EE/LDC).¹²

The no allowance allocation scenario has benefits that accrue outside the model, such as through funding of other programs or tax reductions.

Output-based allocation provides incentives to *producers* that favor the eligible technologies, and by promoting in-state generation, it has the potential to reduce emissions leakage.¹³ The leakage rate will be reduced in scenarios where the allowance value is reinvested in the electricity sector. Nonetheless, the production incentive embodied in output-based allocation also provides an indirect benefit to

consumers; by expanding production, this approach usually reduces or reverses the potential increase in electricity price. Some of the consumer benefits may accrue outside the regulated region because of the transmission of electricity over state borders.

In contrast, allocating allowance value to end-use energy efficiency and/or local distribution companies is expected to benefit electricity *consumers* directly. Energy efficiency investments reduce electricity consumption and by doing so reduce electricity prices, which reduce consumers' overall bills. Allocation to local distribution companies will directly reduce electricity prices by assumption, although several other uses are possible.¹⁴ The two approaches conflict somewhat, because energy efficiency spending lowers consumption, whereas lower electricity prices encourage greater consumption, but both approaches work to deliver energy services to consumers at lower cost.

The second dimension along which we vary the policy scenarios is linking. We imagine the introduction of carbon pricing on a go-it-alone basis and as a linked program with RGGI. Expanding the cap-and-trade market across jurisdictions offers the opportunity to harvest greater gains from allowance trading. In states with cost-of-service regulation of the electricity sector, these gains are expected to accrue to the benefit of consumers whether the state is a seller or buyer of allowances, because the opportunity to trade provides cost savings in either case.

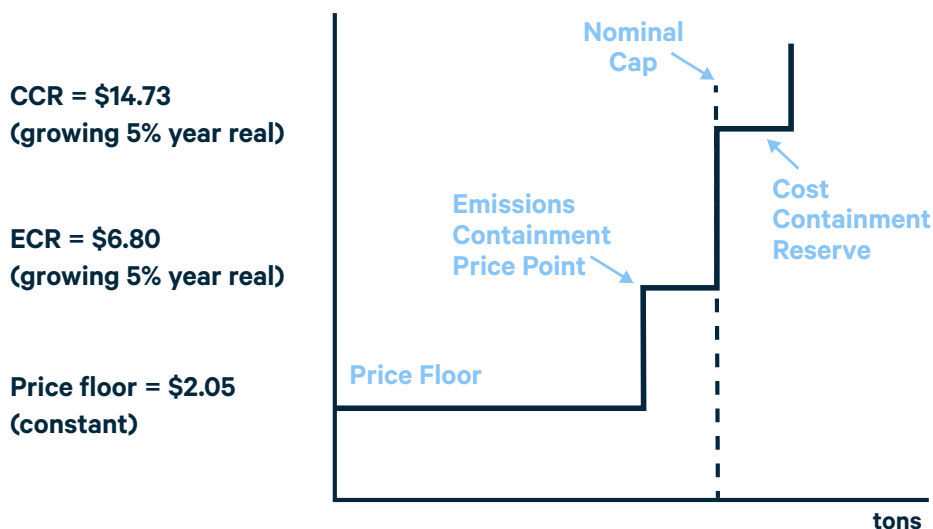
The third dimension we examine includes policies to support technology. We examine a renewable technology policy (RTS), which is different from a renewable portfolio standard (RPS). In the RTS, the fraction of retail sales that must be provided with renewable energy expands by 5 percent by 2026 and 10 percent by 2031, but unlike an RPS, which allows renewable energy credits to come from outside the state, the RTS we model requires the expansion of renewable supply to be achieved *within* each state with no interstate trading of renewable technology credits (RTCs). In practice, limiting compliance to within the state may have dormant Commerce Clause implications: RPS policies have avoided this by allowing for the use of renewable energy credits from out of state. However, the approach we use in the model enables us to portray the explicit goal embodied in many state energy plans to achieve the development of renewable resources within the state. As a consequence, our RTS approach will lead to in-state construction and associated costs that are higher than those with a conventional RPS, so they cannot be compared directly.

We vary the approach taken in the three geographic regions to provide a variety of examples. In the upper Midwest states, we layer cap and trade on top of the RTS policy, although we also consider cap and trade separately. In North Carolina and Pennsylvania, we do the converse, modeling the cap-and-trade policies separately and layering on an RTS.

We vary the policy scenarios along three dimensions. The first is how states decide to allocate allowances; the second is linking; the third includes policies to support technology.

The model is solved through 2031. Emissions outcomes and allowance prices vary over the modeling horizon and investments respond to allowance and electricity price signals. We focus attention on midterm outcomes in 2026, a year that coincides with an expected program review. All prices are reported in real 2015\$. Figure 2 describes the allowance supply schedule. In 2026, the emissions containment reserve trigger price is \$6.80/ton, and the cost containment trigger price is \$14.73/ton. The price floor remains constant at \$2.05/ton. Emissions are measured in short tons.

Figure 2. The allowance supply schedule (2026 prices in 2015\$)



Results Summary

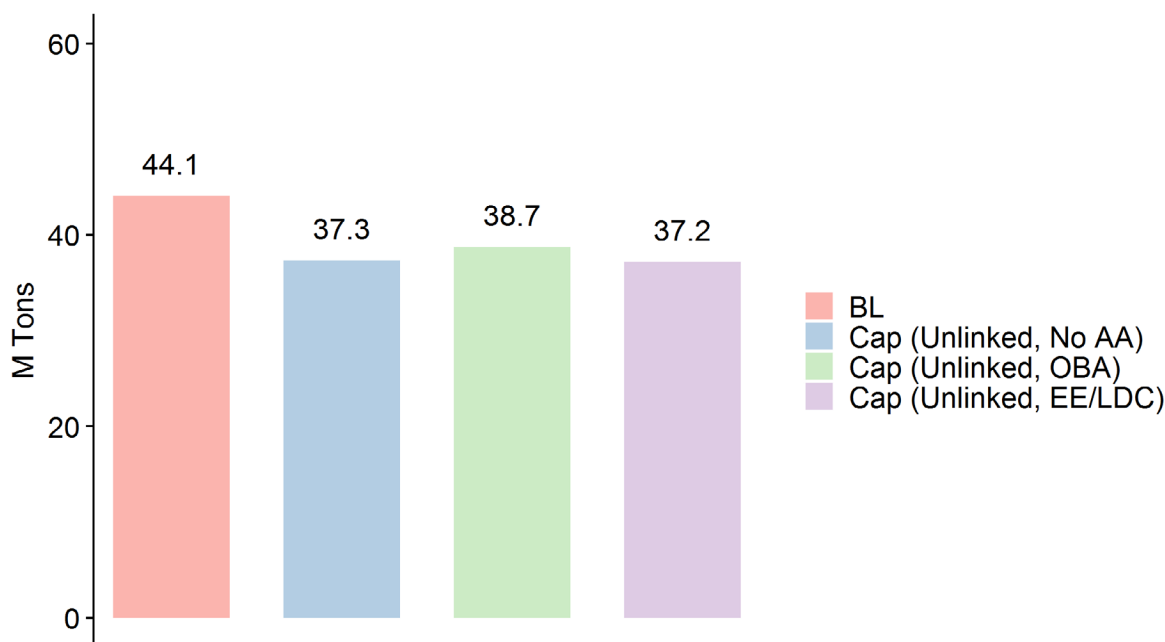
Policies to limit CO₂ emissions and promote clean energy can have varied impacts on electricity producers and consumers within a state or region, including shifts in the generation mix and regional power trading. Further, the impacts of policies depend on the business-as-usual baseline that would unfold without the policy, which is uncertain. Thus complete comparisons of different policy approaches are multidimensional in scope.

We build the model baseline using recent assumptions about capacity investment and retirement and capacity utilization where available. Over time, in the baseline and in policy scenarios, the model chooses capacity additions and retirement and operation of the system to minimize costs. Against the recent updates to the baseline, the costs of CO₂ allowances under cap and trade are low, frequently triggering the emissions containment reserve and often at the price floor. When allowance prices are low, emission reductions occur at an accelerated rate, because some allowances under the nominal cap do not enter the market. Figure 3 shows that the emissions from covered sources in North Carolina in the baseline are 44.1 million tons in 2026.

When allowance prices are low, emission reductions occur at an accelerated rate.

The emissions outcomes differ in three cap-and-trade scenarios employing different approaches to allowance allocation. With no allowance allocation, the allowance price falls to the price floor and emissions fall to 37.3 million tons, which is below the nominal cap of 43.1 million tons. Output-based allocation provides a production incentive that drives emissions up to 38.7 million tons, but the allowance price remains on the price floor and emissions remain below the nominal cap. Allocation to consumers through energy efficiency and returning funds to local distribution companies results in emissions of about 37.2 million tons. Nearly 40 percent of the emissions reduction in North Carolina is partially eroded through an increase in emissions from uncovered sources inside and outside the state—the phenomenon known as leakage under no allowance allocation and allocation to consumers through energy efficiency spending and local distribution companies. The leakage is reduced to about 20 percent under output-based allocation.

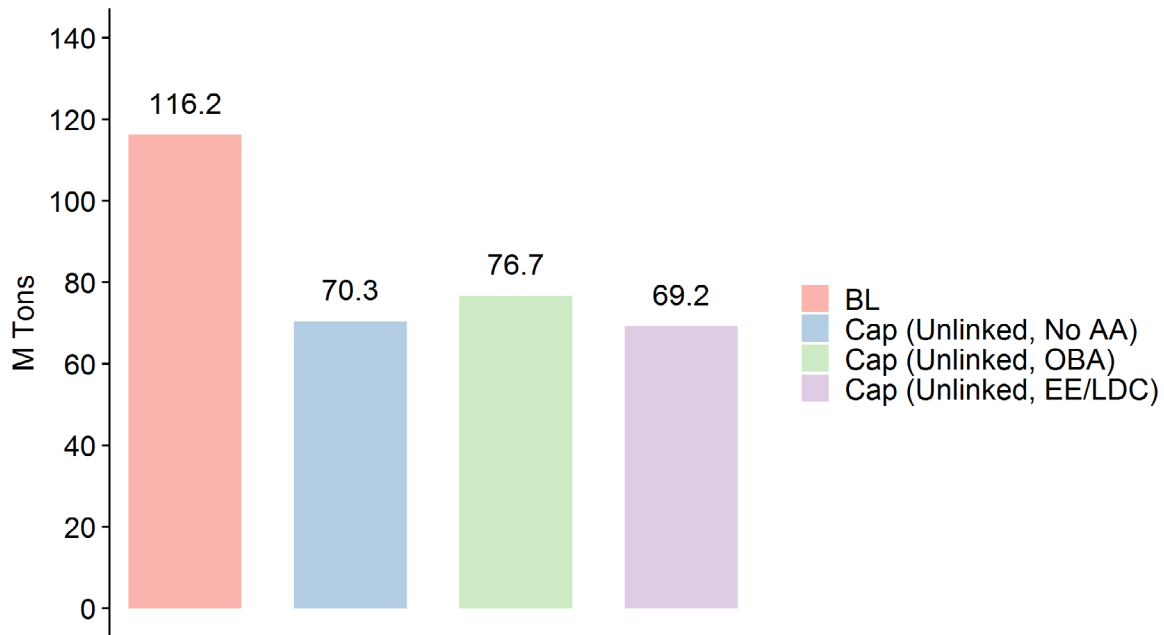
Figure 3. Emissions outcomes in North Carolina in 2026 under various cap-and-trade scenarios



We describe electricity price changes qualitatively in North Carolina and the Midwest states because the model does not account fully for changes in the embedded costs in the cost-of-service states when capacity utilization changes, but we see small changes in the resource costs in North Carolina, as evidenced by the low allowance price.

The baseline has also evolved considerably in Pennsylvania, where the expanded supply and declining price of natural gas has led to an upward revision to estimates of emissions in the baseline. Figure 4 illustrates that emissions are expected to be 116.2 million tons in 2026 in the baseline. The reductions associated with cap and trade are substantial in comparison, but the model nonetheless suggests they can be achieved at a low allowance price that in many cases will trigger the emissions containment reserve, leading to emissions outcomes that are below the nominal emissions cap. With no allowance allocation, emissions are 70.3 million tons. Output based allocation encourages generation, and emissions rise to 76.7 million tons, the nominal emissions cap, as the allowance price rises above the emissions containment reserve price. Emissions are lowest, at 69.2 million tons, with allocation to consumers through energy efficiency spending and local distribution companies. However, emissions are least on a national basis under output-based allocation, because the increased generation in Pennsylvania leads to a reduction in generation and emissions in other states. In addition, output-based allocation leads to the greatest amount of renewable generation, roughly doubling that in the other scenarios, creating an infrastructure for ongoing transformation to a low-emissions electricity sector.

Figure 4. Pennsylvania emissions in 2026 under alternative approaches to allowance allocation



We describe electricity price changes quantitatively in Pennsylvania where electricity prices are determined in the wholesale power market. Across all the cap-and-trade scenarios, we observe electricity price changes that are never more than one-half of one percent compared with the baseline. Emissions leakage is about one third under no allowance allocation or with allocation to consumers through energy efficiency spending and local distribution companies. However, under output-based allocation, emissions pricing in Pennsylvania results in negative leakage, implying that emissions reductions at the national level are greater than those achieved in Pennsylvania because the allocation approach provides an incentive to bring generation into the state, which has a cap on emissions. When linking to RGGI, where the allowance price is projected to be on the price floor without linking to a new state, we see an increase in emissions in Pennsylvania and a commensurate reduction in emissions in RGGI relative to the unlinked programs.

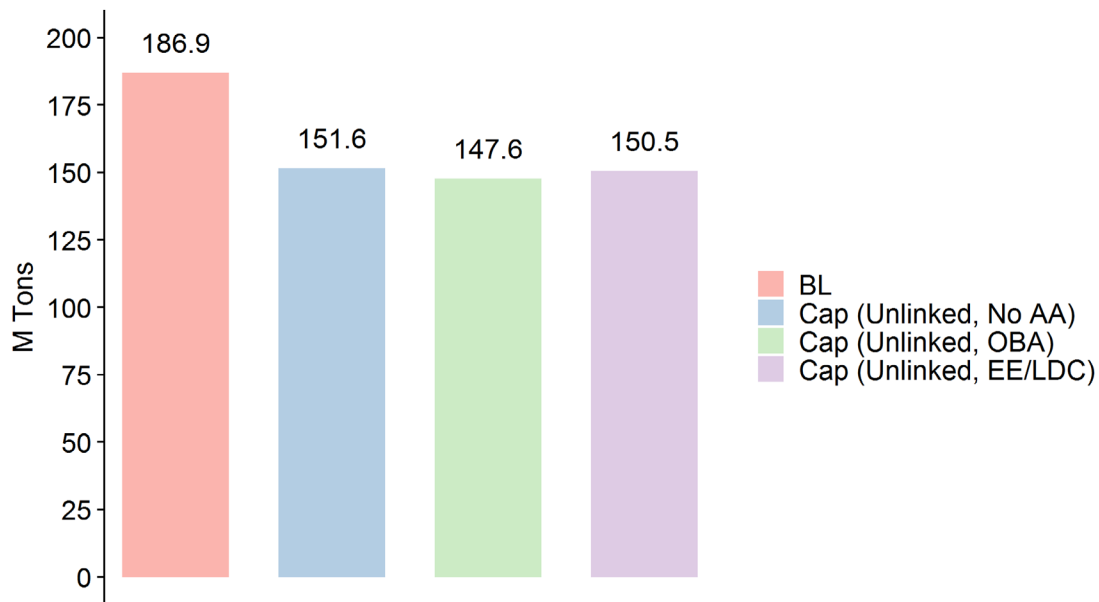
In the four Midwest states, we take a different tack and assume a renewable technology policy (RTS) is in place and cap and trade is layered on top of that policy. As we noted previously, the RTS we model requires investments in renewables to occur within the state, which is unlike realistic renewable portfolio standards that allow renewable credits from outside the state to be used for compliance. Although some RTS measures may have Dormant Commerce Clause implications and would be more expensive than a renewable portfolio standards, an RTS is useful in the model to illustrate the cost of the technology outcome.

We report outcomes for the four Midwest states as a group in a linked Midwest regional program. We note that outcomes for the region are sensitive to our baseline assumptions and evidence suggests state policies may lead the baseline to evolve

importantly from the baseline we construct on the basis of EIA (2017).¹⁵ The Midcontinent Power Sector Collaborative also expects the emissions baseline in the central US to be getting cleaner over the next decade (Great Plains Institute 2018). We have not updated the baseline for the Midwest states, so we expect the analysis to project a high forecast of costs for achieving emissions targets that we model and results at the state level thus may be more conservative than what would be projected with updated specific baseline information from these states.

Figure 5 illustrates that emissions in the baseline are 186.9 million tons. The RTS alone (not shown in Figure 5) achieves emissions reductions of only 6 million tons compared with the baseline, although it doubles the amount of renewable generation in the region. In contrast, Figure 5 shows that in each of the cap-and-trade policies, emissions fall to the vicinity of 150 million tons. The emissions price in each of these scenarios is below the emissions containment reserve price, so emissions vary across scenarios.

Figure 5. Emissions under a renewable technology standard coupled with different approaches to allowance allocation in four upper Midwest states in 2026



In each case, there are slightly more renewables than under the technology standard alone. Leakage is over one-third with no allowance allocation or with allocation to consumers through energy efficiency and local distribution companies. Output-based allocation provides an incentive for greater generation in the states and leakage falls to 12 percent. Linking of the Midwest states with RGGI leads to a slight increase in emissions in the Midwest and a commensurate increase in RGGI relative to the unlinked programs. In the following sections, we present model results in greater detail, beginning with North Carolina.

Results: Carbon Pricing in North Carolina

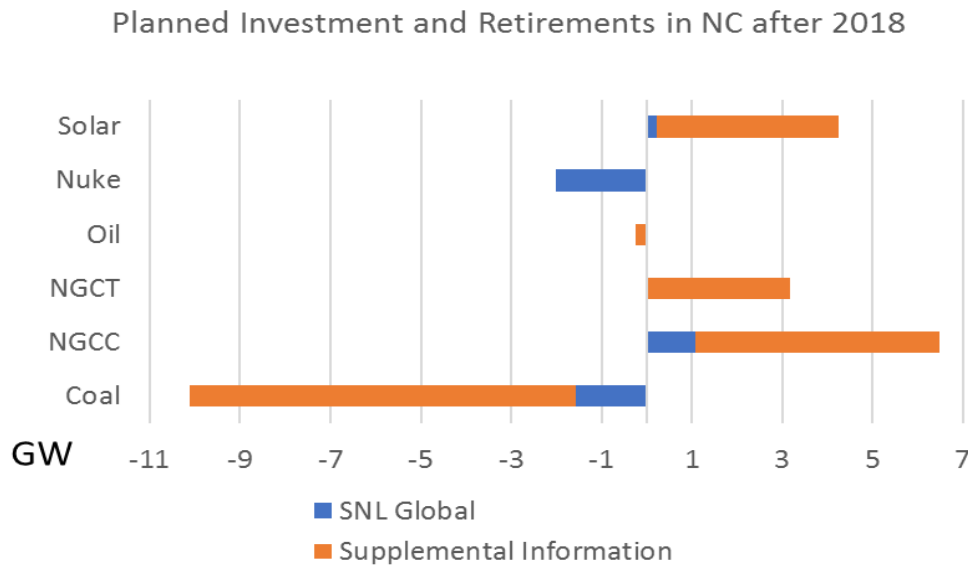
We examine policy options in North Carolina including an RTS, separately from carbon pricing, and in combination. Compared to only an RTS, we find carbon pricing improves the cost-effectiveness of emissions reductions in 2026 with less new renewable capacity because carbon pricing provides incentives for emissions reductions unrelated to renewables technologies by shifting from coal to gas generation, for example on the coal/gas margin. The scenarios for carbon pricing vary according to the scope of trading (unlinked or link with RGGI) and the approach to allowance allocation. The scenario names and definitions for North Carolina are summarized in Table 1.

Table 1. Scenario definitions for analysis of North Carolina

Scenario name	Policy type	CO ₂ policy trading scope	CO ₂ policy allowance allocation
Baseline (BL)	—	—	—
RTS	RTS	—	—
Cap No AA Unlinked	CO ₂ cap	NC	No allocation
Cap No AA Linked	CO ₂ cap	NC & RGGI	No allocation
Cap OBA Unlinked	CO ₂ cap	NC	OBA
Cap OBA Linked	CO ₂ cap	NC & RGGI	OBA
Cap OBA Linked (RTS)	CO ₂ cap + RTS	NC & RGGI	OBA
Cap EE_LDC Unlinked	CO ₂ cap	NC	50% EE, 50% LDC
Cap EE_LDC Linked	CO ₂ cap	NC & RGGI	50% EE, 50% LDC

Baseline assumptions for North Carolina have evolved as coal units have retired and new natural gas and solar units have come into service. Figure 6 illustrates assumed changes in capacity expected after 2018 as identified by SNL Global and from supplemental information gathered from integrated resource plans and other sources. This baseline serves as a point of departure for changes in capacity identified in various modeled scenarios.

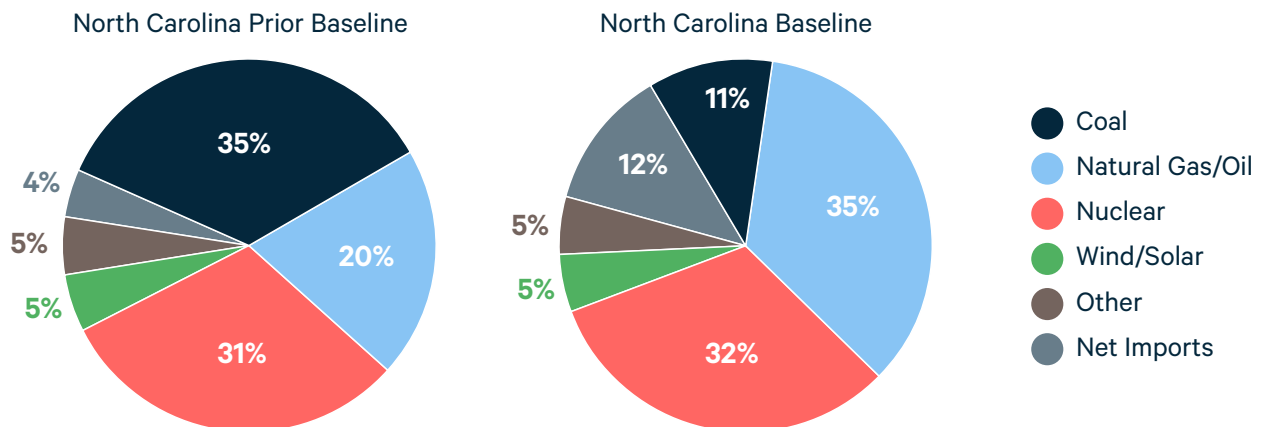
Figure 6. Assumed baseline capacity additions and retirements in North Carolina after 2018



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

The changing capacity, relative fuel prices, and other factors have also changed the expected utilization of capacity. Figure 7 illustrates the change in generation technology from a prior baseline based on EIA (2017) to our current baseline. Consumption in North Carolina fell in the revised baseline fell by almost one percent. The baseline generation and emissions outcomes are also reported in the first column of Table 2. Carbon emissions are forecast as 46.4 million tons in 2026. Emissions from sources that would be covered under the cap-and-trade scenarios are 44.1 million tons.

Figure 7. Prior and updated baseline generation mix for North Carolina in 2026



The RTS policy, reported in the second column of Table 2, would double the amount of renewable generation in the state, decrease net imports by 3.5 TWh, and reduce emissions in the state by 4.7 million tons. However, the time-of-day availability of in-state renewable power crowds out some investment in renewable capacity and renewable generation from out of state in those time blocks. The increase in renewable generation in state, and reduction in net imports, lead to less investment in nonemitting capacity and less generation from nonemitting sources outside the state. Consequently, we find greater utilization of preexisting coal and gas capacity outside North Carolina, and national emissions fall by only 2 million tons.

Table 2. North Carolina technology policies and carbon pricing without allocation

North Carolina, 2026	Baseline (BL)	RTS	Cap (No AA)	
		Unlinked	Unlinked	RGGI linked
US				
CO ₂ emissions [M tons]	1,719	1,717	1,715	1,716
NC				
Electricity consumption [TWh]	139	135	139	139
Generation total [TWh]	130	131	122	122
Coal	16.7	13.6	11.7	11.7
Natural gas/oil	51.4	48.7	48.4	48.4
Nuclear	47.4	47.4	47.4	47.4
Wind/solar	7.3	13.9	7.3	7.3
Other	7.1	7.1	7.1	7.1
Net imports [TWh]	18.3	13.5	26.4	26.4
CO ₂ emissions [M tons]	46.4	41.7	40.1	40.1
CO ₂ pricing policy				
Covered emissions [M tons]	44.1	39.7	37.3	37.3
Allowances issued [M tons]	0.0	0.0	37.3	38.5
Allowance price [\$ /ton]	0.0	0.0	2.1	2.1
Allowance value [M\$]	0	0	77	79
Technology standard				
Credit price [\$ /MWh]	0.0	35.1	0.0	0.0

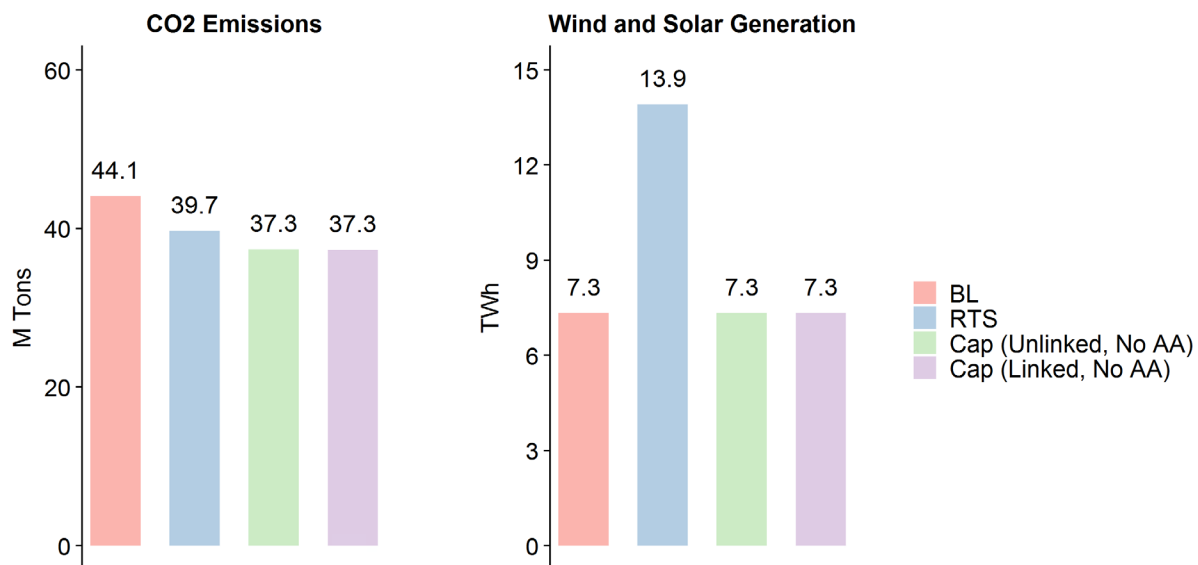
Cap and Trade with No Allowance Allocation

The cap-and-trade policies achieve greater emissions reductions than the technology policies, with a smaller increase in the total cost of electricity service in the state. Column 3 of Table 2 reports that cap and trade with no allowance allocation achieves emissions reductions of 6.7 million tons from baseline emissions of 44.1 million tons at sources covered by the program. The allowance price is on the price floor, and allowances issued (37.3 million tons) are less than the nominal cap (43.1 million tons) implying that emissions reductions are achieved at greater than 3 percent per year. The emissions reduction is achieved primarily through a reduction in coal generation and some reduction in natural gas generation. Whereas the RTS policy resulted in an increase in generation from in-state renewables, the cap-and-trade policy leads to an increase in imports. Leakage of emissions from covered sources to uncovered sources inside and outside the state is about 40 percent.

Column 4 shows that linking North Carolina with RGGI has little effect on the results because both programs have allowance prices on the price floor. The linked program continues to be on the price floor with a very slight increase in the allowances issued in North Carolina and a slight increase in allowance value, but virtually no change in emissions in the state and little leakage.

The main results for the scenarios in Table 2 are illustrated in Figure 8.

Figure 8. Emissions and renewable energy under the RTS and cap with no allowance allocation in North Carolina in 2026



Allocation to Producers

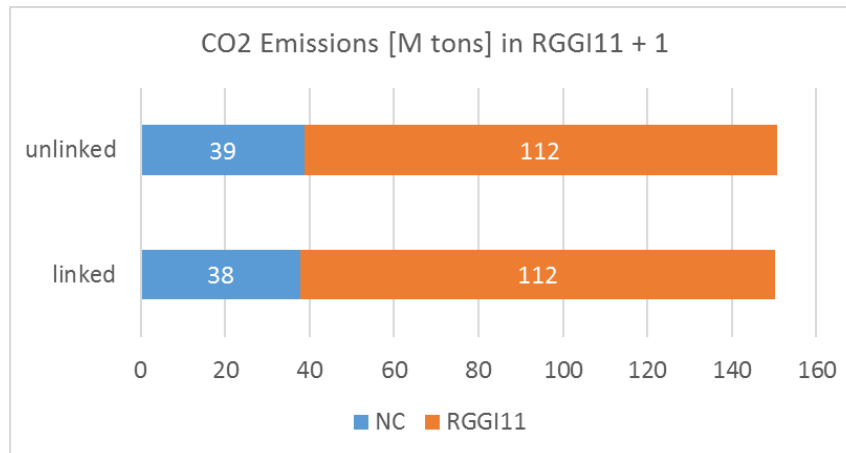
Results with output-based allocation of allowance revenue to producers are reported in column 2 of Table 3, revealing a small increase in generation (3 TWh) in the unlinked scenario compared with no allowance allocation (Table 2), while imports decrease by 2.2 TWh. Emissions from covered sources increase by 1.4 million tons compared with no allowance allocation because of the production incentive in the allocation approach. The allowance price remains on the price floor, and allowances issued remain below the nominal cap. National emissions fall compared with no allocation, although only slightly. Leakage to sources outside the state and to uncovered sources in the state is about 20 percent.

Table 3. North Carolina carbon pricing with allocation to producers or consumers

North Carolina, 2026	Baseline (BL)	Cap (OBA to all except coal)			Cap (AA to EE/LDC)	
		Unlinked	RGGI linked	Unlinked (+ RTS)	Unlinked	RGGI linked
US						
CO ₂ emissions [M tons]	1,719	1,715	1,712	1,715	1,715	1,715
NC						
Electricity consumption [TWh]	139	139	139	135	138	138
Generation total [TWh]	130	125	123	128	122	122
Coal	16.7	11.8	11.7	11.3	11.7	11.7
Natural gas/oil	51.4	50.8	49.7	48.6	48.2	48.2
Nuclear	47.4	47.4	47.4	47.4	47.4	47.4
Wind/solar	7.3	7.3	7.3	13.9	7.3	7.3
Other	7.1	7.1	7.1	7.1	7.1	7.1
Net imports [TWh]	18.3	24.2	25.1	16.2	25.2	25.4
CO ₂ emissions [M tons]	46.4	41.0	40.7	39.1	40.0	40.0
CO ₂ pricing policy						
Covered emissions [M tons]	44.1	38.7	37.9	37.1	37.2	37.2
Allowances issued [M tons]	0.0	38.7	38.6	37.1	37.2	38.4
Allowance price [\$ /ton]	0.0	2.1	2.1	2.1	2.0	2.1
Allowance value [M\$]	0	79	79	76	76	79
Technology policy						
Credit Price [\$ /MWh]	0.0	0.0	0.0	34.1	0.0	0.0

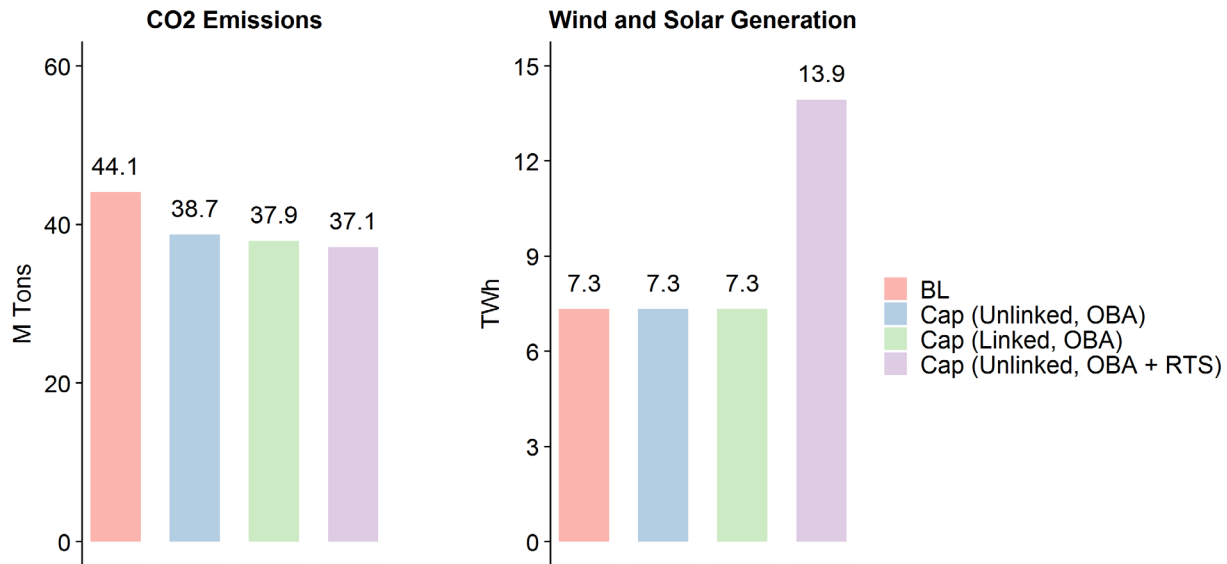
When North Carolina uses output-based allocation and links with RGGI (column 3 of Table 3), the allowance price remains on the price floor, but the demand for allowances at that price rises slightly. Linking has little effect, and most measures remain almost the same as in the unlinked case. Covered emissions in North Carolina fall and covered emissions in RGGI rise slightly, and national emissions are reduced compared with no linking, resulting in negative leakage in the joined program, with reductions at the national level greater than reductions in the trading program. The emissions outcome in the linked region is illustrated in Figure 9.

Figure 9. Emissions in North Carolina with output-based allocation and in RGGI in 2026



In column 4 of Table 3, we report the outcome when we overlay an RTS with cap and trade with output-based allocation and without linking to RGGI. The RTS leads to an increase in renewable generation compared with the similar scenario without an RTS (column 2) and a slight decrease in natural gas generation in the state, but it also leads to a reduction in electricity consumption because the cost of service and the price seen by customers increase to pay for the RTS. The allowance price remains on the floor, and the allowances issued and emissions from covered sources fall by 1.6 million tons. National emissions reductions remain slightly greater than the reductions from the covered sources across the linked program. The emissions and technology outcomes for North Carolina under output-based allocation are illustrated in Figure 10.

Figure 10. Emissions and renewable energy for North Carolina in 2026 under output-based allocation

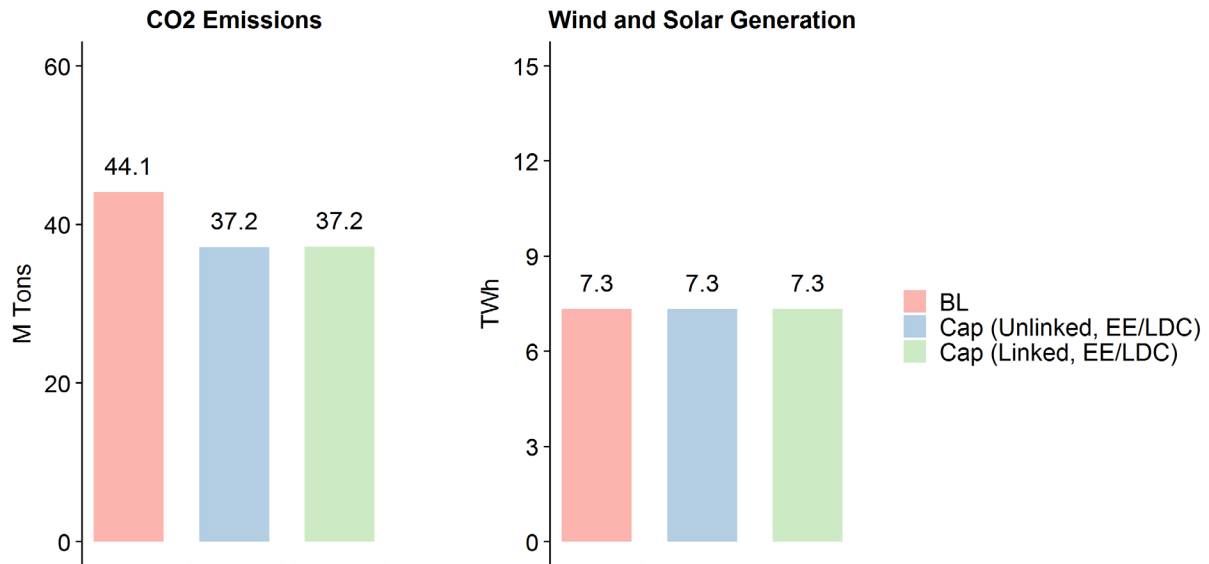


Allocation to Consumers

Allocation to consumers through energy efficiency spending and return of allowance value to local distribution companies leads to a slight net reduction in electricity consumption compared with the baseline. Column 5 of Table 3 shows the allowance price remains on the price floor. The allowances issued and emissions from covered sources are at their lowest level among the scenarios considered here: 37.2 million tons. Leakage to uncovered sources inside and outside the state rises as in the scenario with no allowance allocation: approximately 40 percent.

Linking to RGGI, reported in column 6, results in little change, as the allowance price remains on the price floor. The emissions from covered sources remain unchanged and well below the nominal cap, but the allowances issued in North Carolina increase by 1.2 million tons, which enables a commensurate increase in emissions in RGGI. Leakage in the linked program is unchanged from the unlinked case. The emissions and technology outcomes for allocation to consumers are illustrated in Figure 11.

Figure 11. Emissions and renewable energy in North Carolina in 2026 under allocation to consumers



Results: Carbon Pricing in Pennsylvania

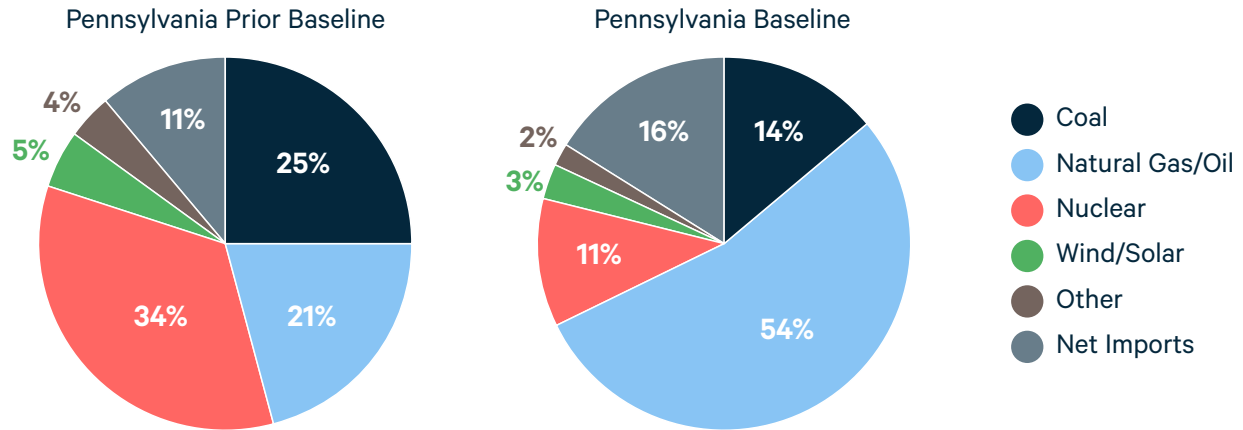
The policy options we examine in Pennsylvania mirror those we have considered in North Carolina. We consider an RTS before moving to examine carbon pricing. The scenario names and definitions for Pennsylvania are summarized in Table 4.

Table 4. Scenario definitions for analysis of Pennsylvania

Scenario name	Policy type	CO ₂ policy trading scope	CO ₂ policy allowance allocation
BL	—	—	—
RTS	RTS	—	—
Cap No AA Unlinked	CO ₂ cap	PA	No allocation
Cap No AA Linked	CO ₂ cap	PA&RGGI	No allocation
Cap OBA Unlinked	CO ₂ cap	PA&RGGI	OBA
Cap OBA Linked	CO ₂ cap	PA&RGGI	OBA
Cap OBA Linked (RTS)	CO ₂ cap + RTS	PA&RGGI	OBA

Baseline assumptions for Pennsylvania include planned retirement of 914 MW of coal units and 4.5 GW of nuclear sometime after 2018. Investment in 1.9 GW of new natural gas combined cycle (NGCC) is also included in the baseline assumptions. Other capacity changes are identified by the model. Figure 12 shows that the generation mix in Pennsylvania has changed since the 2017-era baseline, with important reductions in nuclear and coal generation and expansion of natural gas generation expected by 2026. Consumption in the revised baseline is virtually unchanged compared to the prior baseline. The first column of Table 5 presents other results for the baseline. The model identifies reduced nuclear capacity and generation in the next decade, based on economic criteria. Total carbon emissions are forecast as 116.2 million tons in 2026 in the new baseline, up from 92.3 million tons that would have been forecast in the prior baseline, reflecting the increase in total generation to 217 TWh, up from 199 TWh in the prior baseline. Emissions from sources that are covered under the cap-and-trade scenarios are forecast to be 116.2 million tons in the new baseline.

Figure 12. Prior and updated baseline generation mix for Pennsylvania in 2026



The RTS policy, reported in column 2 of Table 5, would increase the amount of renewable generation by 8.2 TWh, increase exports slightly, and reduce total emissions in the state by 2.7 million tons, with a commensurate and slightly greater reduction in emissions at the national level.

Table 5. Pennsylvania technology policies and carbon pricing without allocation

Pennsylvania, 2026	Baseline (BL)	RTS	Cap (No AA)	
		Unlinked	Unlinked	RGGI linked
US				
CO ₂ emissions [M tons]	1,719	1,716	1,689	1,688
PA				
Electricity consumption [TWh]	165	165	164	164
Generation total [TWh]	217	218	193	207
Coal	35.4	34.9	22.7	29.5
Natural gas/oil	139.7	135.5	72.5	85.4
Nuclear	28.1	25.0	75.2	74.3
Wind/solar	7.4	15.6	14.7	9.8
Other	6.5	6.5	8.1	8.0
Net imports [TWh]	−41.4	−41.8	−17.8	−31.3
CO ₂ emissions [M tons]	116.3	113.6	72.0	84.3
CO ₂ pricing policy				
Covered emissions [M tons]	116.2	113.5	70.3	82.8
Allowances issued [M tons]	0.0	0.0	70.3	69.0
Allowance price [\$/ton]	0.0	0.0	6.8	3.8
Allowance value [M\$]	0	0	478	264
Technology standard				
Credit Price [\$/MWh]	0.0	0.5	0.0	0.0

Cap and Trade with No Allowance Allocation

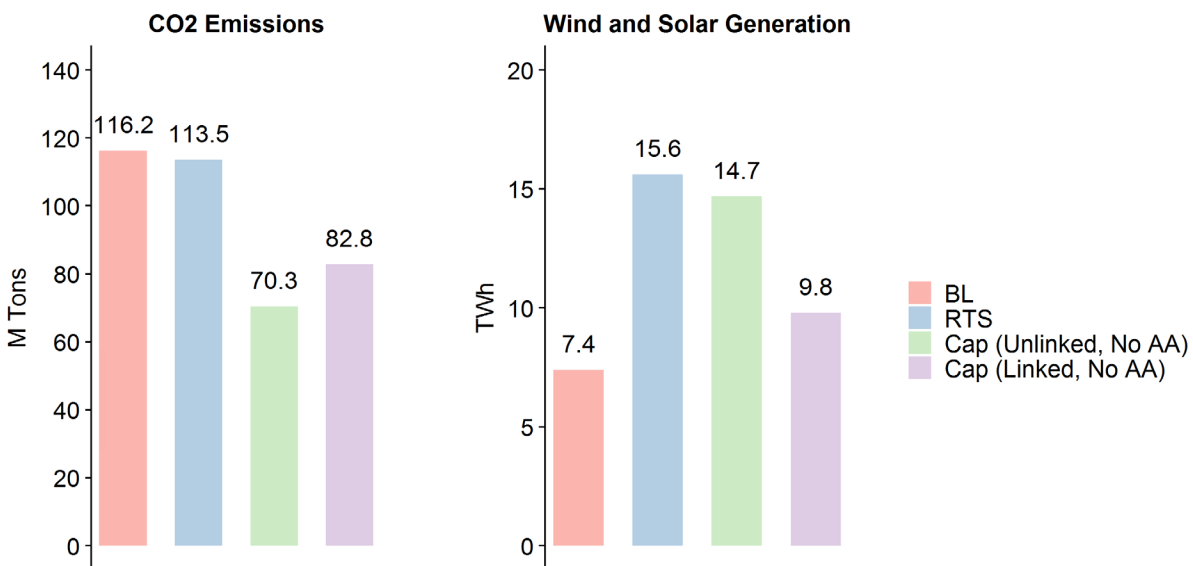
As in North Carolina, the cap-and-trade policies as modeled in Pennsylvania achieve greater emissions reductions than the technology policy. Column 3 of Table 5 reports emissions reductions of 46 million tons in the state, over 10 times those achieved under the RTS, if the state does not allocate allowances within the power sector. The allowance price is \$6.8/ton, at the price trigger for the emissions containment reserve, and issued allowances are 6.4 million tons less than the nominal cap of 76.7 million tons. In Pennsylvania, the electricity price is determined by the wholesale market price, and we can identify that it changes by less than one-half of one percent compared with the baseline. The emissions reduction is achieved largely through a reduction in gas generation, some reduction from coal, and the

survival of existing nuclear plants, and it involves almost as much generation from renewables as the RTS policy. Exports fall by 24 TWh, which is replaced by generation outside the state. Consequently, leakage of emissions reductions from covered sources to uncovered sources inside and outside the state is about one-third.

Linking Pennsylvania with no allowance allocation with RGGI leads to a reduction in the allowance price in Pennsylvania from \$6.8 to \$3.8/ton. Column 4 reports that generation from coal and gas plants increases and the state increases its emissions from covered sources from 70.3 to 82.8 million tons, with a commensurate reduction in emissions from RGGI in the linked system. Total emissions from covered sources across the linked region fall from 182.5 to 181.2 million tons because the emissions containment reserve is fully implemented. There is a very small decrease in the electricity price compared with the unlinked scenario. The leakage rate across the linked system is unchanged compared with the unlinked system: about one-third.

The main results for the scenarios in Table 5 are illustrated in Figure 13.

Figure 13. Emissions and renewable energy for Pennsylvania in 2026 under the RTS and cap with no allowance allocation



Allocation to Producers

Column 2 of Table 6 reports results for output-based allocation of allowance revenue to producers in an unlinked program in Pennsylvania. This allocation leads to a substantial increase in generation (17 percent) compared with the no-allocation scenario (Table 5) and a small reduction in the electricity price to just below the baseline level. Exports increase substantially compared with the no-allocation

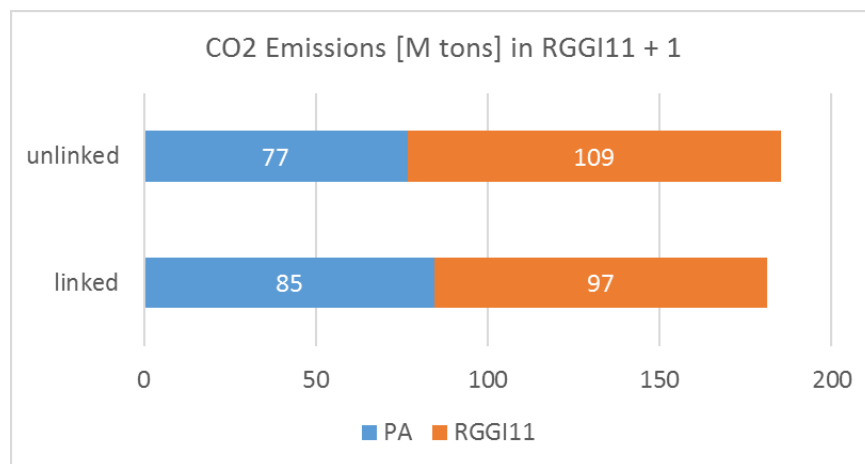
scenario and by 9.3 TWh compared with the baseline, absorbing the increase in generation. The allowance price rises to \$8.6/ton, which is above the emissions containment reserve, so issued allowances equal the nominal cap. Covered emissions increase from 70.3 million tons in the no-allocation case to 76.7 million tons. Output-based allocation is expected to reduce leakage, and indeed it leads to negative leakage by pulling generation into the state and bringing it under the emissions cap, so emissions reductions at the national level are greater than the reductions in Pennsylvania.

Table 6. Pennsylvania carbon pricing with allocation to producers or consumers

Pennsylvania, 2026	Baseline (BL)	Cap (OBA to all except coal)			Cap (AA to EE/LDC)	
		Unlinked	RGGI linked	Unlinked + RTS	Unlinked	RGGI linked
US						
CO ₂ emissions [M tons]	1,719	1,677	1,683	1,677	1,689	1,688
PA						
Electricity consumption [TWh]	165	165	165	165	159	162
Generation total [TWh]	217	227	220	227	190	208
Coal	35.4	21.1	27.7	21.1	22.7	29.5
Natural gas/oil	139.7	91.6	94.0	91.6	70.0	83.9
Nuclear	28.1	77.8	75.3	77.8	73.3	71.5
Wind/solar	7.4	29.6	16.3	29.6	16.2	15.4
Other	6.5	6.5	6.8	6.5	8.1	7.2
Net imports [TWh]	−41.4	−50.7	−44.4	−50.6	−20.2	−34.9
CO ₂ emissions [M tons]	116.3	76.8	84.9	76.8	70.9	83.0
CO ₂ pricing policy						
Covered emissions [M tons]	116.2	76.7	84.6	76.7	69.2	82.2
Allowances issued [M tons]	0.0	76.7	69.0	76.7	69.2	69.0
Allowance price [\$ /ton]	0.0	8.6	3.5	8.6	6.8	3.7
Allowance value [M\$]	0	659	240	660	471	254
Technology standard						
Price [\$ /MWh]	0.0	0.0	0.0	0.0	0.0	0.5

When Pennsylvania links with RGGI (column 3 of Table 6), using output-based allocation, the allowance price falls to \$3.5/ton, triggering full implementation of the emissions containment reserve. Consequently, the allowances issued in Pennsylvania fall to 69 million tons, but emissions increase to 84.6 million tons as Pennsylvania facilities buy allowances from RGGI. Total emissions from covered sources in the linked region fall from 185.3 to 181.3 million tons. The electricity price in Pennsylvania is unchanged from the price in the baseline. Leakage of emissions reductions from covered sources is about 20 percent compared with baseline emissions. The emissions outcomes in the linked regions are illustrated in Figure 14.

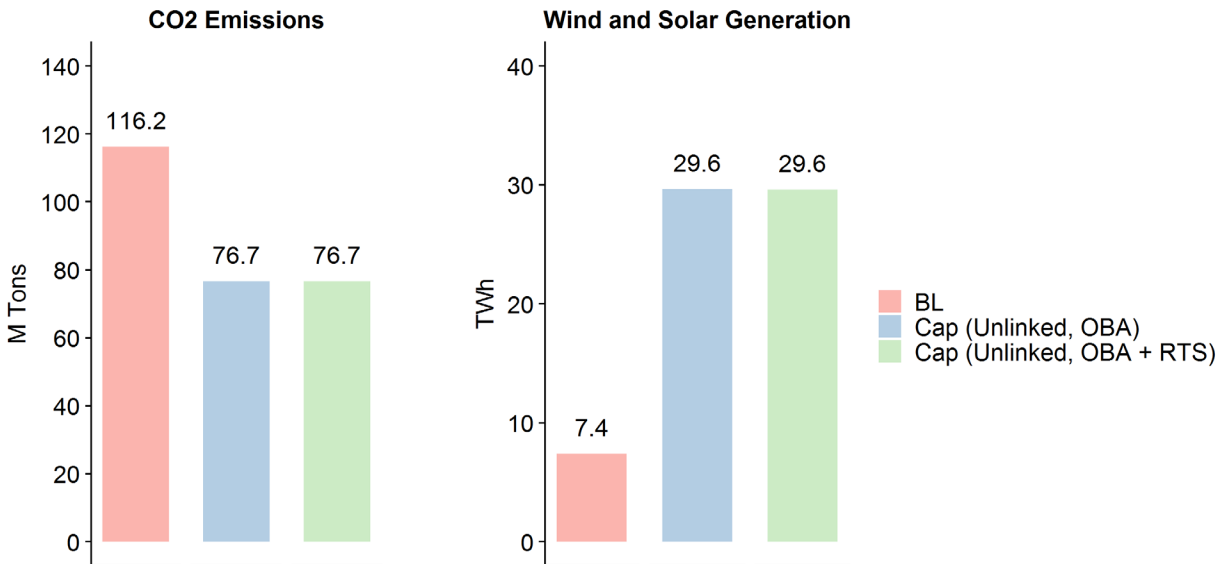
Figure 14. Emissions in Pennsylvania with output-based allocation and in RGGI in 2026



Column 4 of Table 6 reports a scenario that combines output-based allocation without linking to RGGI but with an RTS in Pennsylvania. The amount of renewable generation in this scenario is unchanged from the same scenario without linking, because carbon pricing alone fully achieves the renewables generation goal of this scenario. There is a zero RTC price, and hence the outcome is the same as in column 2. The emissions and technology outcomes for the output-based allocation scenarios are illustrated in Figure 15.

[In this case] output-based allocation. . . leads to negative leakage by pulling generation into the state and bringing it under the emissions cap.

Figure 15. Emissions and renewable energy for Pennsylvania in 2026 under output-based allocation

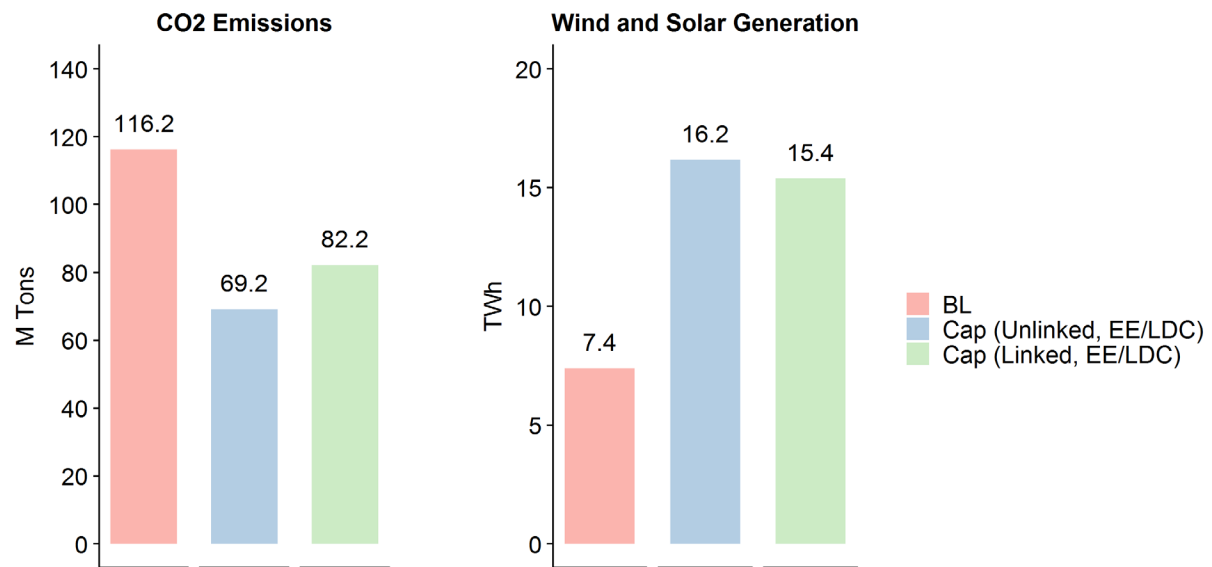


Allocation to Consumers

Column 5 of Table 6 reports the outcome with allocation to consumers when Pennsylvania is not linked to RGGI. Total generation in the state is less than under output-based allocation to producers (column 2) and slightly below the no-allocation scenario (Table 5) because of energy efficiency spending. The allowance price is at the price trigger for the emissions containment reserve, and emissions from covered sources and total emissions in Pennsylvania are lowest of all scenarios. However, there is a decrease in power exports, and the leakage to uncovered sources inside and outside the state is just over one-third. One source of emissions increase outside the state comes from RGGI, which realizes an increase in its allowance price to \$2.5/ton because of reduced power imports from Pennsylvania and increasing costs of compliance in the region. The increased price is above the price floor, enabling an increase in the allowances issued in the region. The leakage rate is about one-third.

Linking to RGGI (column 6 of Table 6) causes the allowance price for Pennsylvania to fall to \$3.7/ton, triggering the full implementation of the emissions containment reserve. Consequently, the allowances issued in the state fall from 69.2 to 69 million tons. Emissions from covered sources increase to 82.2 million tons, and emissions from covered sources in RGGI fall from 112.2 to 99.1 million tons, so total emissions from covered sources in the linked region fall by 0.1 million tons. The electricity price and leakage rate are virtually unchanged. Figure 16 illustrates the emissions and technology outcomes.

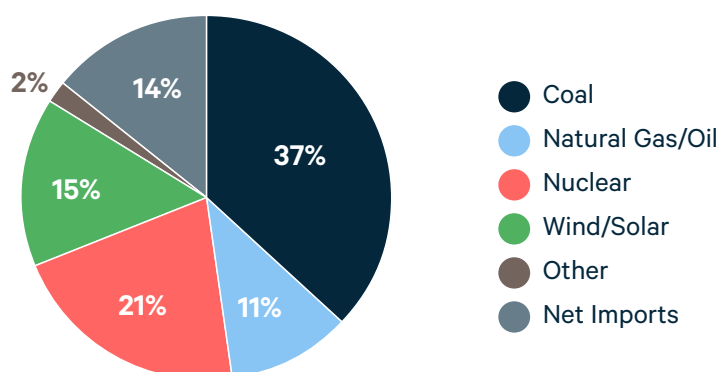
Figure 16. Emissions and renewable energy outcomes in Pennsylvania in 2026 under allocation to consumers



Results: Carbon Pricing in Upper Midwest States

In the upper Midwest, we focus on four states—Illinois, Michigan, Minnesota, and Wisconsin—all of which have had renewable portfolio standards in place for several years. Information from SNL Global suggests planned retirement of 2.1 GW of coal and 11.4 GW of nuclear capacity, as well as the planned addition of 920 MW of NGCC, sometime after 2018. The 2026 generation mix in our baseline scenario is illustrated in Figure 17.

Figure 17. The baseline generation mix for four Midwest states in 2026



We assume growing trajectories of solar and wind penetration in the absence of any new policies, but more ambitious renewables policies are a possibility in each state.¹⁶ To represent this, we simulate a renewable technology standard (RTS) in which the fraction of retail sales that must be provided with renewable energy in each of the four states expands by 5 percent by 2026 and 10 percent by 2031. Although the existing renewables policies in these states allow compliance to come from outside the state, as in the cases discussed above, we require the expansion of renewable supply to be achieved within each state with no interstate trading of credits associated with the incremental RTS that we model. As noted earlier, this approach could have dormant Commerce Clause implications, and it will lead to a higher estimate of cost than with a typical renewable portfolio standard that allows credits to be acquired from outside of the state, but we investigate this approach for modeling convenience to investigate the effects of an instate renewable technology policy approach.

We maintain the state-specific RTS policy in most of the analyses of the upper Midwest that consider a rubric of approaches to CO₂ emissions pricing. We pay attention to results at the aggregated level for the four Midwest states. These scenarios are listed in Table 7, and all except the baseline and one other (as

indicated) have the RTS in place. The CO₂ emissions pricing scenarios differ along two dimensions. One is the scope of trading: separate but identical state programs are labeled “Alone,” programs in the Midwest that are linked are labeled “Midwest,” and programs that link the Midwest and RGGI are so indicated. The second dimension is the approach to allowance allocation, where we consider the three approaches that have already been introduced: no allocation, allocation to producers (output-based allocation), and allocation to consumers (50 percent to energy efficiency and 50 percent to local distribution companies). Results are always presented as a total across the four Midwest states or, where appropriate, as a weighted average.

Table 7. Scenario definitions for analysis of upper Midwest states

Scenario name	Policy type	CO ₂ policy trading scope	CO ₂ policy allowance allocation
BL Midwest	—	—	—
RTS Midwest	RTS	—	—
Cap No AA Midwest Alone	RTS + CO ₂ cap	Alone	No allocation
Cap No AA Midwest	RTS + CO ₂ cap	Midwest	No allocation
Cap No AA RGGI Midwest	RTS + CO ₂ cap	Midwest&RGGI	No allocation
Cap OBA Midwest Alone	RTS + CO ₂ cap	Alone	OBA
Cap OBA Midwest	RTS + CO ₂ cap	Midwest	OBA
Cap OBA Midwest&RGGI	RTS + CO ₂ cap	Midwest&RGGI	OBA
Cap OBA Midwest (No RTS)&RGGI	CO ₂ cap	Midwest&RGGI	OBA
Cap EE_LDC Midwest Alone	RTS + CO ₂ cap	Alone	50% EE, 50% LDC
Cap EE_LDC Midwest	RTS + CO ₂ cap	Midwest	50% EE, 50% LDC

Results for the business-as-usual baseline (BL) for the year 2026 are reported in the first column of Table 8. Column 2 reports the expansion of the RTS, which results in an increase in generation and imposes a system cost that leads to a small reduction in consumption, so that net imports (imports minus exports) into the region fall from 58.3 TWh (15 percent of consumption) to 39 TWh (10 percent of consumption). Renewable generation increases by 38 percent, while generation from natural gas and nuclear falls modestly, and coal generation is nearly unaffected. Total emissions in the region fall by 6 million tons (3 percent).

Table 8. Midwest scenarios with no allowance allocation

Midwest, 2026	Baseline (RGGI 11)	RTS	RTS + CO ₂ cap (No AA)		
			Alone	Midwest	RGGI & Midwest
US					
CO ₂ emissions [M short tons]	1,756	1,751	1,733	1,734	1,735
MN, WI, IL, MI					
Electricity consumption [TWh]	396	390	389	390	390
Generation total [TWh]	365	378	356	359	360
Coal	155.3	154.3	132.7	135.0	135.6
Natural gas/oil	47.7	42.5	34.0	33.4	34.5
Nuclear	87.3	82.1	88.1	88.5	87.7
Wind/solar	65.9	90.8	92.0	92.8	92.7
Other		7.9	9.3	9.3	9.3
Net imports [TWh]	58.3	39.0	59.7	57.6	56.8
Total CO ₂ emissions [M tons]	189.0	183.1	154.9	156.8	158.2
CO ₂ pricing policy					
Covered emissions [M tons]	186.9	181.9	151.6	153.6	154.9
Allowances issued [M tons]	0.0	0.0	151.6	153.6	153.6
Allowance price [\$ /ton]*	0.0	0.0	5.7	3.2	2.5
Allowance value [M\$]*	0	0	864	492	384
Technology standard					
Credit price [\$ /MWh]*	0.0	2.9	2.8	2.7	2.8

**Weighted average value for region*

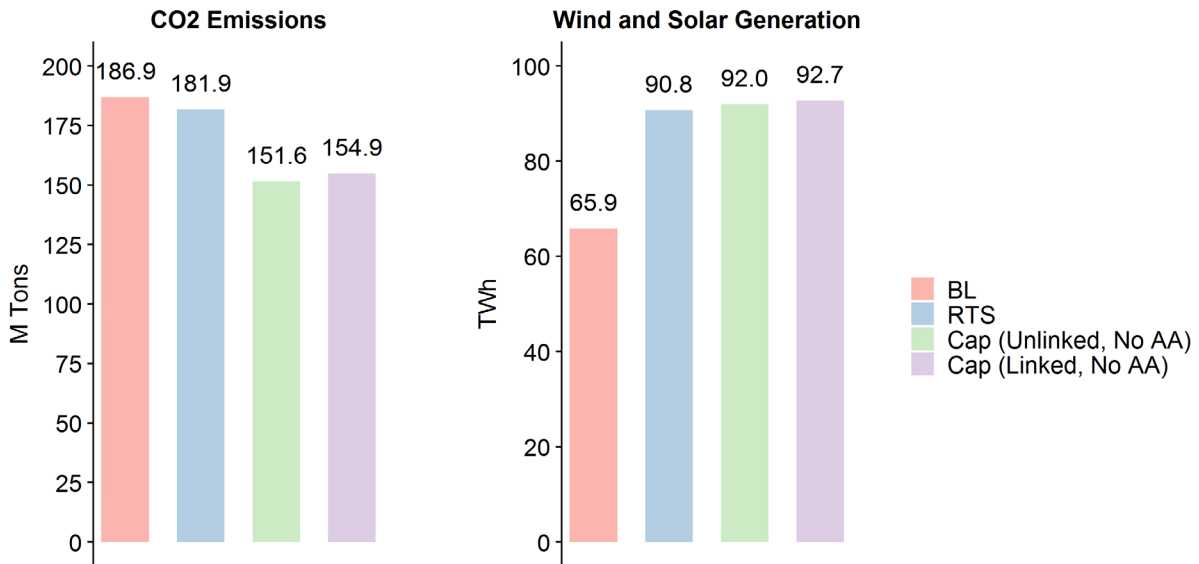
No Allowance Allocation

We next examine the influence of carbon pricing with no allowance allocation, keeping the RTS in place. Beginning with a scenario in which all states introduce separate carbon-pricing programs without trading among the states (column 3), the carbon price causes a decline in coal generation (15 percent from BL) and further reductions in natural gas generation beyond that resulting from the RTS (20 percent from BL), yielding a reduction in total emissions in the region from 189 million tons in the baseline and 183 million tons under the RTS scenario to 155 million tons (18 percent from BL) under the cap. Emissions from sources covered by the regulation fall from 187 to 152 million tons (19 percent). Allowance prices vary across the states, but in two of the four states the price is at the price floor, which reduces the number of allowances issued. About one-third of the emissions reductions achieved within the region reemerge elsewhere in the country.

Column 4 in Table 8 reports the outcome when the four Midwest states link in a regional cap-and-trade program. Emissions in the region increase slightly, as the two states on the price floor under a go-it-alone carbon cap come up off the price floor under the regional trading program, and the number of allowances issued in those states increases accordingly. Generation increases slightly, net imports fall slightly, and the leakage rate for emissions from covered sources is about one-third. Finally, column 5 describes linkage between the collection of Midwest states and RGGI. The Midwest states continue with no allocation, and the RGGI states continue with the approach to allocation represented in the baseline. The allowance price falls slightly, from \$3.2 in the Midwest market to \$2.5 in the RGGI-linked market. There are no substantial changes in the region as a consequence of linking with RGGI because the allowance prices in the unlinked markets are already similar. The leakage rate remains about one-third.

The main results for the RTS and the cap with no allocation are summarized in Figure 18.

Figure 18. Emissions and renewable energy in four Midwest states in 2026 with renewable technology standard cap with no allocation



Allocation to Producers

We next consider the use of allowance value to provide an incentive for generation from specified technologies by way of an output-based allocation to all generation sources covered by the regulation, excluding coal, and all nonemitting generators except existing renewables and hydro. Table 9 repeats the results of the baseline for convenience. Column 2 reports the outcome when states simultaneously enact the output-based allocation policy but do not allow trading across states (“Alone”). We observe a substantial increase in generation in the region (15 percent) and an associated decrease in net imports. The results illustrate that output-based allocation provides an incentive to increase production within the region. Renewable generation more than doubles, and generation from nuclear and natural gas grows as well, while coal falls by 30 percent. However, the consumers that benefit are not necessarily those within the region. National emissions fall by 34 million tons, resulting in a leakage rate of only 13 percent, much lower than that in the scenarios that assume no allocation of allowances within the electricity sector.

Table 9. Midwest scenarios with allocation to producers

Midwest, 2026	Baseline (BL)	RTS+CO ₂ cap (OBA)			OBA (no RTS)
		Alone	Midwest	Midwest & RGGI	Midwest & RGGI
US					
CO ₂ emissions [M short tons]	1,756	1,722	1,728	1,731	1,731
MN, WI, IL, MI					
Electricity consumption [TWh]	396	381	390	390	391
Generation total [TWh]	365	421	368	365	361
Coal	155.3	109.2	128.8	131.7	130.4
Natural gas/oil	47.7	61.4	41.5	38.4	41.2
Nuclear	87.3	105.0	95.3	93.3	95.2
Wind/solar	65.9	137.2	93.4	92.9	84.8
Other	8.6	8.4	9.1	9.1	9.1
Net imports [TWh]	58.3	−14.0	47.8	50.9	57.3
Total CO ₂ emissions [M tons]	189.0	149.7	156.7	157.1	158.0
CO ₂ pricing policy					
Covered emissions [M tons]	186.9	147.6	153.6	154.0	154.9
Allowances issued [M tons]	0.0	147.6	153.6	153.6	153.6
Allowance price [\$ /ton]*	0.0	10.2	2.3	2.4	2.5
Allowance value [M\$]*	0	1,500	358	368	377
Technology standard					
Credit price [\$ /MWh]*	0.0	2.2	2.7	2.7	0.0

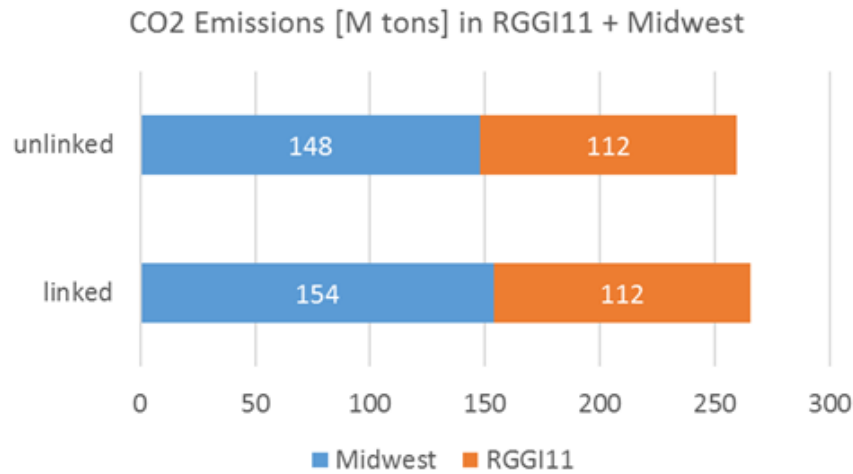
**Weighted average value for region*

The linking of states in the region under output-based allocation is reported in column 3 (“Midwest”) of Table 9. In this scenario, allocation occurs at the state level, but allowance trading is interstate. The linking among the Midwest states causes a substantial decline in the electricity price. The allocation approach encourages generation in the region to increase from 359 TWh with no allocation to 368 TWh, with an associated decrease in net imports of 10 TWh. This also leads to a decrease in generation outside the region and the lowest national emissions; the leakage rate in this scenario is only 13 percent.

We next look at linking of the collection of Midwest states with RGGI. The Midwest states continue with output-based allocation, and the RGGI states continue with the approach to allocation represented in the baseline. Consumption and generation are nearly unchanged.

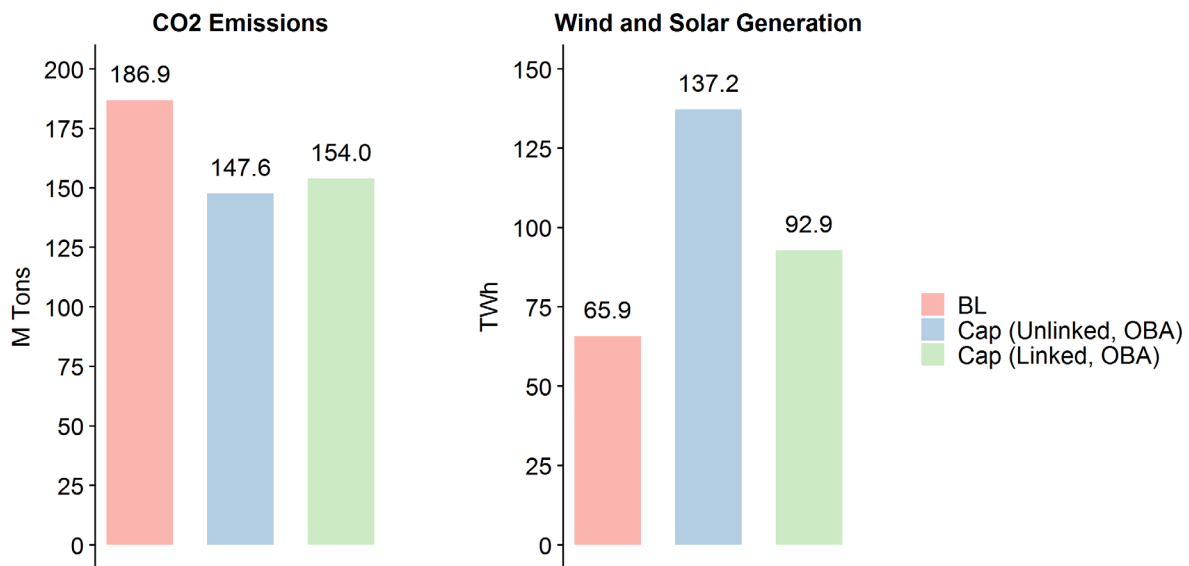
The emissions outcomes in the linked regions are illustrated in Figure 19.

Figure 19. Emissions in four Midwest states with renewable technology standard and output-based allocation and in RGGI in 2026



The emissions and technology outcomes for the output-based allocations (with the RTS in place) are illustrated in Figure 20.

Figure 20. Emissions and renewable energy in four Midwest states in 2026 with a renewable technology standard and output-based allocation



In all the cap-and-trade scenarios thus far, we have assumed the incremental RTS is also in place. In column 5 of Table 9, we imagine a cap-and-trade program in the Midwest that has allocation to producers and is linked to RGGI but where the incremental RTS in each state is not in effect. Total generation and net imports are relatively unchanged from the baseline, but the generation mix is cleaner. Leakage is about 22 percent.

Allocation to Consumers

The final approach we analyze is allocation to consumers through an increase in energy efficiency spending and allocation to local distribution companies. Column 2 of Table 10 reports the outcome across the four states when states act independently (“Alone”). Compared with the relevant no-allocation and output-based allocation scenarios, consumption, generation, and emissions in the region fall slightly, as expected. Consumption falls by about the same as generation, but the increase in renewable generation crowds out some investment in renewable capacity and renewable generation out of state and results in an associated increase in gas generation outside the state, and leakage rises to 43 percent.

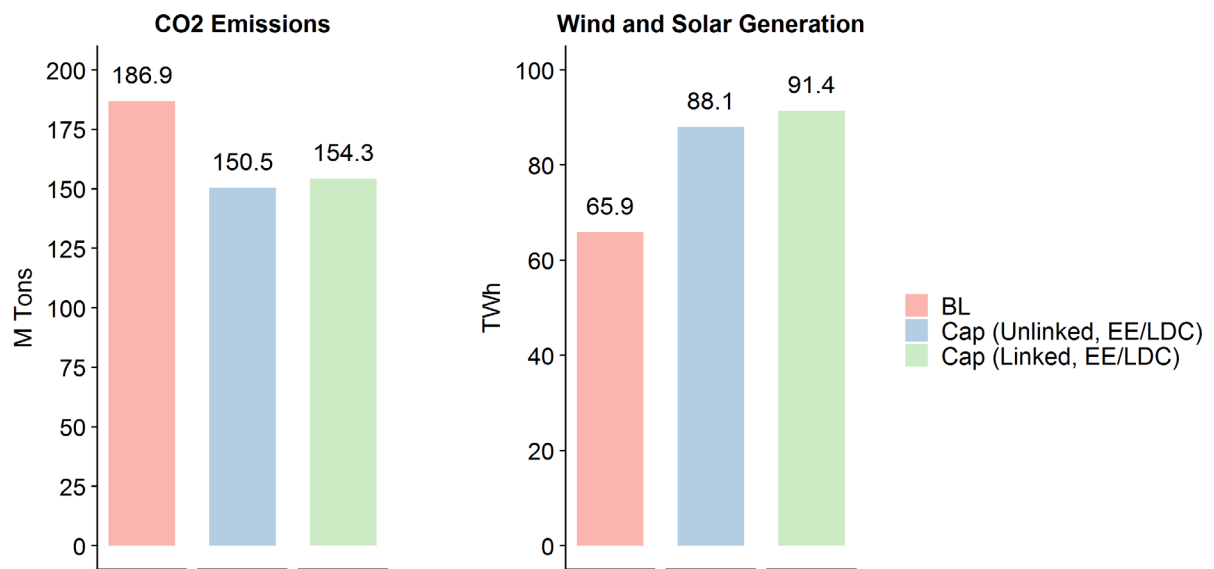
Table 10. Midwest scenarios with allocation to consumers

Midwest, 2026	Baseline (BL)	RTS+CO ₂ cap (EE/LDC)		
		Alone	Midwest	Midwest&RGGI
US				
CO ₂ emissions [M short tons]	1,756	1,736	1,737	1,737
MN, WI, IL, MI				
Electricity consumption [TWh]	396	381	385	385
Generation total [TWh]	365	350	353	357
Coal	155.3	132.3	135.1	135.5
Natural gas/oil	47.7	33.4	33.5	33.8
Nuclear	87.3	87.1	86.9	86.9
Wind/solar	65.9	88.1	88.7	91.4
Other	8.6	9.3	9.3	9.3
Net imports [TWh]	58.3	56.8	57.5	54.7
Total CO ₂ emissions [M tons]	189.0	153.8	156.8	157.6
CO ₂ pricing policy				
Covered emissions [M tons]	186.9	150.5	153.6	154.3
Allowances issued [M tons]	0.0	150.5	153.6	153.6
Allowance price [\$ /ton]*	0.0	5.5	3.1	2.5
Allowance value [M\$]*	0	834	470	382
Technology standard				
Credit price [\$ /MWh]*	0.0	3.4	3.1	2.8

**Weighted average value for region*

Linking among the Midwest states, as reported in column 3 of Table 10 (“Midwest”) reduces the allowance price (compared to the weighted average allowance price in column 2), which will reduce the electricity price and cause consumption and generation to increase slightly. The leakage rate for emissions reductions across the four states is 40 percent. Linking of the Midwest states with RGGI (column 4) leads to a slight decline in the allowance price, as expected. The emissions and technology outcomes are illustrated in Figure 21.

Figure 21. Emissions and renewable energy in four Midwest states in 2026 with a renewable technology standard and allocation to consumers



Conclusion

As states consider various approaches to confronting climate change and reducing their greenhouse gas emissions, pricing carbon through a cap-and-trade program is one option that states are actively considering. This modeling analysis focuses on two eastern states, Pennsylvania and North Carolina that are contiguous to RGGI, and a group of four Midwest states. This modeling suggests that implementing a cap to deliver a 30 percent reduction in emissions from 2020 levels in the electricity sector by 2030 is likely to have low allowance prices and small impacts on electricity prices. The cost of a carbon-pricing program will depend on how the mix of generation is expected to evolve in the absence of the program. Our modeling indicates that carbon pricing will be more effective at reducing emissions than a policy focused exclusively on encouraging increased electricity generation from wind and solar because it will provide an incentive for the greater use of natural gas in place of coal, although it will result in less renewable generation capacity at the end of the decade. Combining a renewable technology policy with carbon pricing can increase the amount of generation from wind and solar beyond that which would occur under a carbon price alone and can do so without large impacts on electricity prices.

When a state (or group of states) pursues a policy of pricing carbon in electricity markets, emissions leakage to noncovered emitting sources, both within the state and in other states through regional power trading, can be a concern. We find that employing a method of allowance allocation that provides incentives to generate electricity within the state can accomplish two goals simultaneously: mitigation of electricity price increases and of emissions leakage. In some situations, the allowance allocation can lead to national emissions reductions that exceed those within the state alone by bringing more covered generation under a cap. Linking of new state emissions trading programs with RGGI has different impacts in the various cases we consider here and various benefits that are not addressed in the modeling. The cost savings of linking to RGGI can be small because the state-level programs as we describe them share the architecture and general ambition of RGGI. Nonetheless, linking will make a program more resilient to unexpected events affecting electricity or carbon markets and make state-level efforts more influential in the national policy discussion.

Appendix: Literature Review

Much of the research and learning about the design of carbon markets has been done within the context of RGGI, to inform its initial development (Burtraw, Kahn, and Palmer 2006), to inform subsequent program review–related modifications (Burtraw et al. 2018), as part of periodic assessments of the economic consequences of the program and associated state investment of allowance revenues (Hibbard et al. 2018), and to draw lessons that could be transferred to other programs (Ramseur 2017). In addition, a robust literature has emerged about linking emissions trading programs and how different approaches to linking might affect the outcomes.

One of the key issues in the economics literature is how the initial distribution (allocation) of emissions allowances in a cap-and-trade program can affect the program's performance. Research has shown that the free allocation of emissions allowances would have different implications for electricity prices in competitive regions than in regulated regions (Parry 2005, Burtraw et al. 2001). In a competitive market, actors are expected to incorporate the opportunity cost (i.e., market price) of allowances used to cover their emissions in determining the price of goods they sell into the market, whether those allowances were obtained for free or at a cost (Wråke et al. 2010). Therefore, in electricity markets, the opportunity cost of using an allowance to generate electricity would be reflected in electricity prices paid by consumers even under free allocation (Burtraw and Palmer 2008). Before the implementation of the RGGI program, the electricity industry in the region had deregulated, so customers in the RGGI states would be paying the cost of allowances no matter how they were distributed. In recognition of this reality, the RGGI states decided to initially distribute allowances using an auction that would provide revenue that could be put toward other purposes (Raymond 2016, Paul et al. 2010). With the exception of a small auction in Virginia as part of the regional nitrogen oxide (NO_x) budget program (Porter et al. 2009), RGGI was the first cap-and-trade program to auction allowances. The research on allowance auction design done for RGGI (Holt et al. 2007, Shobe et al. 2010, Burtraw et al. 2011) has proven formative in other programs that have adopted an auction.

Virginia's decision to link with RGGI changed the dynamic because the electricity industry in the state operates under cost-of-service regulation. As a regulated state, Virginia saw free allocation of allowances to emitting generators as a way to reduce the costs of this new regulation to electricity customers. However, to link with RGGI required Virginia to implement cost containment features of the RGGI model rule, including the price floor, emissions containment reserve, and cost containment reserve. Consequently, Virginia chose to require generators to consign the freely allocated allowances to be sold in the RGGI auction, with the revenues to flow back to the generators (Burtraw and McCormack 2017).

RGGI and other cap-and-trade programs have paid attention to the possibility that emissions reductions from sources covered by the program could be partially eroded by emissions increases from unregulated sources in another jurisdiction, an outcome termed “emissions leakage,” but in general, the issue has not been found to be severe (Musgrove et al. 2017). The effects of a shift in generation to generators outside the region have been largely offset by a decrease in the emissions intensity of generation outside the region (Regional Greenhouse Gas Initiative 2018). This issue may be particularly relevant for electricity, which flows freely (subject to transmission constraints) within each of three large interconnections within the United States (and including Canada). Regulations potentially can be imposed at the border of wholesale electricity markets within these large interconnections (Bushnell, Chen, and Zaragoza-Watkins 2014), but most electricity markets span multiple states. Consequently, all the existing cap-and-trade programs regularly monitor this issue. Empirical assessments in RGGI have found leakage to be evident (Fell and Maniloff 2018), which has the effect of increasing the cost per ton of emissions reductions achieved but does not overturn the multiple benefits of the program (Hibbard et al. 2018, Murray and Maniloff 2015).

Various elements of program design can help mitigate leakage, including the use of output-based allocation of allowances to in-state generators based on their share of recent production of electricity in the state, which has been studied in the context of the regional nitrogen oxide budget program (Lange and Maniloff 2017, Fischer and Fox 2007). A version of this approach to distributing allowances is used to protect industries that are exposed to unfair trade with neighboring jurisdictions that do not regulate carbon in both the EU Emissions Trading System (Löfgren et al. 2018) and the California cap-and-trade program. It was also used by some states in the electricity sector NO_x Budget Trading Program and was a feature available to the states under the Clean Power Plan to encourage production from the set of regulated facilities while providing an incentive to substitute away from relatively higher-emitting generation sources to cleaner sources (Palmer et al. 2017, Borenstein et al. 2018). Burtraw et al. (2015) conducted simulations of the upper Midwest region, one of the regions considered in this study, and this study shows that in some cases using allowances as an in-state production incentive can result in negative emissions leakage—that is, emissions in neighboring jurisdictions can go down.

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Notes

- 1 www.c2es.org.
- 2 <http://programs.dsireusa.org/>.
- 3 The original RGGI states were Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Maryland, and Delaware. Subsequently, New Jersey left RGGI. New Jersey is expected to rejoin in 2020. In the modeling, we assume Virginia links to RGGI in 2020, although that outcome has been recently put on hold.
- 4 <https://www.usclimatealliance.org/>
- 5 In Virginia, this allocation to generators is based not on fixed shares, but on each generator's share of in-state generation by covered sources in recent years. Because almost all of the generation in the state is owned by a regulated utility, the free allocation of allowances provides a benefit to consumers.
- 6 <https://www.rggi.org/program-overview-and-design/design-archive/mou-model-rule>.
- 7 The model was first built in 1998 and has been used in over two dozen peer-reviewed publications and reports for various federal, state, and regional organizations. Documentation on version 2 of the model appears in Paul et al. (2009). Documentation on the current version (3) is forthcoming.
- 8 Vermont does not have a competitive market, but has a minimal contribution to emissions in the electricity sector.
- 9 Note that New Hampshire and Maine did not intend to implement emissions containment at the time that the 2016 Program Review was released.
- 10 Energy efficiency receives 51.5 percent, bill assistance through local distribution companies receives 12.8 percent, output allocation directed to renewable energy receives 17.5 percent, and 18.1 percent is direct outside the program through research and development, general funds, education and other programs.
- 11 Note that in RGGI, the first several years of the decade beginning in 2021 are characterized by a bank adjustment to the cap to allow the market to absorb the outstanding private bank that carries over from prior compliance periods. We do not include such an adjustment for the new states, as they do not have a preexisting bank.
- 12 This compares with 51.5 percent of allowance value directed to energy efficiency and 12.8 percent directed to bill assistance through local distribution companies in the nine-state RGGI in the most recent compliance period (Hibbard et al. 2018).
- 13 The leakage rate is one minus the ratio of the change in emissions (from baseline) at the national level divided by the change within the region.
- 14 In contrast to the approach we describe, in California the value of allowances associated with the electricity sector is returned as a direct per-customer account rebate every six months. The rebate is equal within each service territory. Consequently, consumers do not observe lower bills or infer lower electricity prices on a monthly basis.
- 15 For example, Wisconsin Energy and Xcel Energy have committed to substantial emissions reduction goals suggesting new investments and changes in the utilization of existing capacity. The Integrated Resource Plan for Consumer's Energy describes substantial growth in renewable energy procurement over the next two decades. NRG Energy in Illinois has recently proposed converting its coal units to natural gas.

- 16 Governors in Minnesota and Wisconsin have proposed 100 percent carbon-free electricity by 2050. Legislators in Illinois have proposed 100 percent renewables by 2050. Advocates in Michigan have launched a ballot initiative to require 30 percent renewables by 2030.

