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The Clean Power Plan: Implications of Three Compliance Decisions for U.S. States

Martin T. Ross, Brian C. Murray, and David Hoppock

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Author Affiliation
Nicholas Institute for Environmental Policy Solutions, Duke University

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SUMMARY

The proposed Clean Power Plan gives U.S. states flexibility in how they attain state-level carbon dioxide emissions rate goals from existing power plants. This analysis uses the Dynamic Integrated Economy/Energy/Emissions Model to illuminate the implications of three key decisions: whether to choose rate- or mass-based compliance, whether to pursue multistate or individual state compliance, and whether—if allowed in the final rule—to include new natural gas combined cycle (NGCC) units under the emissions limit.

Regarding power sector adjustments, modeling shows that (1) a rate-based approach initially decreases coal generation 25% and increases use of existing NGCC units and construction of new renewables; (2) compared to that approach, a mass-based approach initially increases coal generation and removes incentives for use of existing NGCC and new renewables generation; (3) assumptions about renewables capital costs, energy efficiency savings, and natural gas prices significantly affect generation responses; and (4) rate-based approaches allow for more emissions growth than mass-based approaches post–2030.

Regarding policy costs, the modeling shows that (1) a mass-based approach, especially with multistate cooperation, offers large cost savings opportunities; (2) neither approach has a big effect on wholesale electricity prices, but including new NGCC units lowers prices under a rate-based approach and increases them under a mass-based approach; and (3) costs differ across U.S. regions and across the mass- and rate-based approaches within regions.

Executive Summary

The U.S. Environmental Protection Agency's (EPA's) proposed Clean Power Plan (CPP) regulates carbon dioxide (CO_2) emissions from existing power plants in the United States through state-level emissions rate goals with an interim emissions rate goal from 2020 to 2030 and a final 2030 emissions rate limit. These emissions rate goals are based on each state's 2012 historical generation and emissions from affected units—primarily existing coal and natural gas combined cycle (NGCC) units—as well as opportunities for each state to reduce affected unit emissions on the basis of four "building blocks:" improving the heat rate of existing coal generation, increasing NGCC utilization, displacing covered fossil generation with zero emissions generation, and creating demand-side energy efficiency. The proposed CPP intentionally offers states significant flexibility in compliance, which can be achieved through a mix of the building block actions used to set the emissions rate goals as well as through other measures such as retiring existing fossil units and meeting demand with new natural gas generation. Additionally, the proposal allows states to convert their emissions rate goals into mass-based limits and to enter into market-based multistate compliance plans. The proposed rule also seeks comment on the inclusion of new NGCC units under the state emissions limit.

This analysis helps states understand the implications of three key decisions: whether to choose rate- or mass-based compliance, whether to opt for multistate or individual state compliance, and whether—if allowed—to include new NGCC units under the emissions limit. It uses the Dynamic Integrated Economy/Energy/Emissions Model (DIEM), which was developed at Duke University's Nicholas Institute for Environmental Policy Solutions, to compare rate- and mass-based market compliance scenarios—with and without new NGCC units under emissions limits—in state, regional, and national compliance markets to a baseline scenario without the CPP. Additional sensitivities for renewable energy costs, energy efficiency availability, and natural gas prices are also presented.

Rate-based versus Mass-based Compliance

Rate-based compliance creates an economic incentive (a "subsidy") for generation below the emissions rate target and a disincentive (a "tax") for generation above the rate. Mass-based compliance, on the other hand, effectively taxes all generation that produces emissions. These two approaches therefore create different economic signals, as revealed by the modeling results presented here.

If no emissions constraints are placed on new NGCC units, the modeling shows the following:

- Mass-based compliance results in more coal generation in 2020 than rate-based compliance, whereas a rate-based approach leads to more renewable generation.
- Mass-based compliance also utilizes significant new NGCC units, when it is outside of the mass limit.
- Rate and mass-based compliance lead to similar CO_2 emissions impacts in 2020, but total electricity sector emissions begin to rise in 2025 under rate-based compliance. Both rate- and mass-based compliance allow generation and emissions growth from new NGCC units unless a state chooses to include new NGCC units under the CPP.
- Compliance costs are approximately 50% lower with mass-based compliance through 2030; differences between these costs for mass-based compliance and rate-based compliance diminish through 2050.
- Regionally, with the exception of the North Central region and to a lesser degree the western region, mass-based compliance leads to a lower overall production cost than rate-based compliance.

- Wholesale electricity prices initially increase under both rate- and mass-based compliance, but they are lower than the baseline in 2030 for rate-based compliance as existing NGCC units, which are often the marginal generators setting the price, are effectively subsidized in many states.

In essence, mass-based compliance provides more flexibility in mitigation options and introduces fewer market distortions than rate-based compliance, thereby tending to lower the overall cost of achieving a given emissions target. However, the mass-based approach tends to have a larger effect on power prices, because all generation pays for the emissions it generates. The impacts of these price effects can be mitigated in a mass-based system by deploying allowance revenues to compensate parties who are differentially affected by the price changes.

State versus Multistate Compliance

The analysis explores the implications of the states acting together with all other states in their contiguous region to comply with the CPP by trading (rate or mass-based) compliance instruments in the region and finds the following:

- Nationally, regional cooperation in compliance lowers total policy costs under all evaluated scenarios. For instance, under a mass-based approach (new NGCC units not covered), the CPP would add about 1.2 percent to national generation costs between 2015 and 2030 under a regional approach; this total would rise to 1.8 percent (a 50 percent increase) if all states acted alone. The relative magnitude of the cost impact differs slightly for other policy scenarios and timelines.
- This general pattern of cost savings from a regional approach is found in all individual regions except the North Central region.
- Extending trading from regional markets to a single national market further lowers the cost under a mass-based system, but does not necessarily do so in a rate-based system.

In summary, the overall cost of the compliance system is substantially lower if each state can use instruments (allowances, credits) generated in any state within its region; the cost savings would grow larger if instruments from any other state in the country could be used.

Inclusion of New NGCC Units under Emissions Limits

Outcomes for rate- and mass-based compliance including new NGCC are similar:

- Under mass-based compliance, less generation comes from new NGCC units because these units are no longer outside of mass limits (mass limits are higher when new NGCC units are included).
- Including new NGCC units in compliance raises mass-based compliance costs and lowers rate-based compliance costs nationally.

In essence, adding new NGCC units to the regulated universe tightens emissions constraints in a mass-based system and lowers the compliance hurdle in a rate-based system.

The analysis tests the sensitivity of the results to variations in key assumptions and parameters and finds the following:

- Reducing renewable energy capital costs by one-third relative to the U.S. Energy Information Administration's Annual Energy Outlook (AEO) 2014 assumptions and using more optimistic cost improvement rates can increase renewable generation, as expected, especially from 2030 onward. These assumptions and rates increase coal generation under rate-based compliance and decrease new NGCC generation under both rate-based compliance and mass-based compliance.

- Similarly, increased energy efficiency availability increases rate-based coal generation and reduces new NGCC generation in both rate-based compliance and mass-based compliance.
- High and low natural gas price sensitivities, based on AEO 2014, reduce coal generation under low natural gas prices and increase coal and renewable generation under high gas prices for mass-based compliance.

The analysis shows how certain key choices can affect generation mix, cost, and prices in the power sector, generally revealing that more flexibility yields more cost-effective outcomes, as well as the distribution of costs within the regions and states. Individual states will balance cost and distributional considerations, subject to the political, economic, and technological conditions.

Introduction and Preview of Results

In June 2014, the U.S. Environmental Protection Agency proposed the Clean Power Plan to regulate carbon dioxide (CO_2) emissions from existing power plants under section 111(d) of the Clean Air Act. The CPP establishes state-by-state emissions rate goals for affected fossil units, largely existing coal and natural gas combined cycle generators (U.S. EPA 2014a). A key element of the proposal is its flexibility mechanisms: states can achieve emissions reductions through actions such as improving heat rates at coal plants, shifting generation from coal to gas plants that have fewer emissions, and engaging in "outside the fence" options such as renewable generation and energy efficiency programs, and they can smooth adjustments over the first decade of the policy. States can also choose to comply on a multistate basis using emissions markets to trade compliance instruments (allowances or credits) if it reduces their compliance costs. Finally, they can convert the emissions rate-based goals in the CPP into mass-based targets to achieve additional flexibility.

The CPP proposal lays out a detailed series of calculations to estimate state-by-state emissions rate goals that are feasible extensions of current technologies and policies. These goals reflect states' historical generation and emissions and future emissions reduction capabilities as well as four emissions reduction "building blocks." The first building block is based on engineering data concerning possible heat rate improvements at existing coal-fired plants and suggests that units can potentially improve efficiency by 6% over current levels. The second building block assumes that another possible policy response to lower emissions is to pair increased use of existing natural gas combined cycle (NGCC) plants with a reduction in generation at coal-fired plants, thus taking advantage of the higher efficiency of NGCC units and the lower carbon content of natural gas. The third building block is based on potential measures to maintain under-construction and "at risk" nuclear plants and to expand current state policies on renewable portfolio standards (RPSs) to surrounding states in order to expand zero-emitting generation sources. The fourth building block is EPA estimates, based on historical trend data, of states' capacity to achieve energy efficiency savings in electricity.

This analysis uses the Dynamic Integrated Economy/Energy/Emissions Model (DIEM), described below, to evaluate possible impacts of the CPP policy. The DIEM component applied in this work is a detailed electricity dispatch model of U.S. wholesale electricity markets. It represents intermediate- to long-run decisions about generation, transmission, capacity planning, and dispatch of units. To estimate policy impacts, the model minimizes electricity generation costs while meeting electricity demands and environmental policy goals. Several possible policy responses are evaluated: state-by-state emissions rate-based goals for existing fossil fuel-fired units as described in the June 2014 proposal (U.S. EPA 2014a), mass-based goals for these units as described in the November addendum (U.S. EPA 2014b), rate-based goals for existing and new units (based on application of the original state rate goals), and mass-based goals for existing and new units from the November addendum. Each of these four options are evaluated under three assumptions regarding the level of coordination among states in responding to the CPP: states choose to act alone, states form regional groups to realize cost-effective reductions available in their immediate vicinity, and all 48 states in the continental United States work together to meet national goals.

Important findings regarding adjustments in the power sector include the following:

- Under a rate-based approach covering existing units, coal generation drops by approximately 25% at the beginning of the policy, due to a decrease in utilization and to 29 gigawatts of coal-generation retirements beyond those occurring in the baseline as part of the Mercury Air Toxics Standards (MATS).
- A rate-based approach encourages use of existing NGCC units and construction of new renewables.
- Under a mass-based approach covering existing units, coal generation is initially higher than under a rate-based approach; however, a mass-based approach removes incentives for use of existing NGCC and new renewables generation.
- Policy approaches that cover only existing units will lead to a shift into new NGCC units that are outside of the policy.
- Bringing new NGCC units into the policy, whether through rate-based or mass-based approaches, shifts generation back into existing fossil fuel-fired units, along with new renewable generation, rather than incentivizing construction of new NGCC units.
- Alternative assumptions regarding capital costs of renewables, the availability of energy efficiency savings, and natural gas prices can lead to significant shifts in generation responses.
- All four approaches lead to a 32% drop in emissions over the 2020–2030 period, compared to 2005 levels, although rate-based approaches allow for more emissions growth post–2030.

Important findings regarding policy costs include the following:

- Over the first decade of the CPP policy, a mass-based approach costs one-half of a rate-based approach, nationwide.
- Rate-based and mass-based options covering existing units have little effect on wholesale electricity prices. Including new NGCC units in a rate-based approach lowers prices by subsidizing the units that set wholesale prices, whereas a mass-based approach leads to larger price increases because the emissions of these units incur additional costs.
- Costs are not evenly distributed across U.S. regions, and there also are regional differences across the mass-based and rate-based approaches.
- How energy efficiency is modeled and accounted for is important. Data used in the analysis suggest that energy efficiency measures are cost-effective in the baseline, raising the question of whether their cost savings should be reflected in the baseline or in the policy response.

This paper now details the CPP policy and implications of alternative policy responses, describes the model used in the analysis and the specific policy scenarios investigated, and presents policy results for the United States and broad regions of the nation.

Background

On June 2, 2014, the EPA released proposed rules to regulate existing fossil fuel-fired power plants under section 111(d) of the Clean Air Act. The so-called Clean Power Plan's key features include state-by-state emissions rate targets and considerable flexibility to achieve them (Tarr and Adair 2014). The EPA identified "building blocks"—a specific set of strategies states can follow to seek the required reductions, and it used these strategies in constructing a target rate-based emissions goal for each state. However, the states are not bound by the EPA's strategies; they can devise their own policy mechanisms, from command-based to market-based measures, so long as they meet the target emissions rate or an equivalent fixed emissions limit.

Building Block Strategies

The EPA's identified four building block strategies:

1) Improve the efficiency of existing coal plants.
2) Shift, or "redispatch," generation from existing coal plants to existing natural gas-fired plants and from less efficient to more efficient plants within each fleet. New natural gas plants that are already slated for construction could be built earlier than planned to reduce emissions more quickly.
3) Increase generation of zero-emitting energy, including that from renewable sources and nuclear plants that might otherwise be taken offline ("at risk" nuclear).
4) Reduce power demand through energy efficiency programs.

The EPA identifies these building blocks as elements of a best system of emissions reduction (BSER), which the Clean Air Act establishes as a criterion for determining the performance standard for pollutants covered under section 111(d). As such, the EPA determines how the building blocks can be applied state by state on the basis of each state's power generation sources, emissions, and economic feasibility. In this way the EPA has established an emissions rate goal (lbs./MWh) for each state to be CPP compliant. The emissions rate goal calculation follows the following formula:

$$\text{Emissions Rate Target (lb/MWh)} = \frac{CO_2 \text{ Emissions from Affected Fossil Sources (lb)}}{\text{Generation by Affected Fossil Sources (MWh)} + \text{Generation by Under Const \& ``At Risk'' Nuclear (MWh)} + \text{Generation by Renewable Sources (MWh)} + \text{``Generation'' by Energy Efficiency (MWh)}}$$

The emissions rates established for each state can be found in U.S. EPA (2014c).

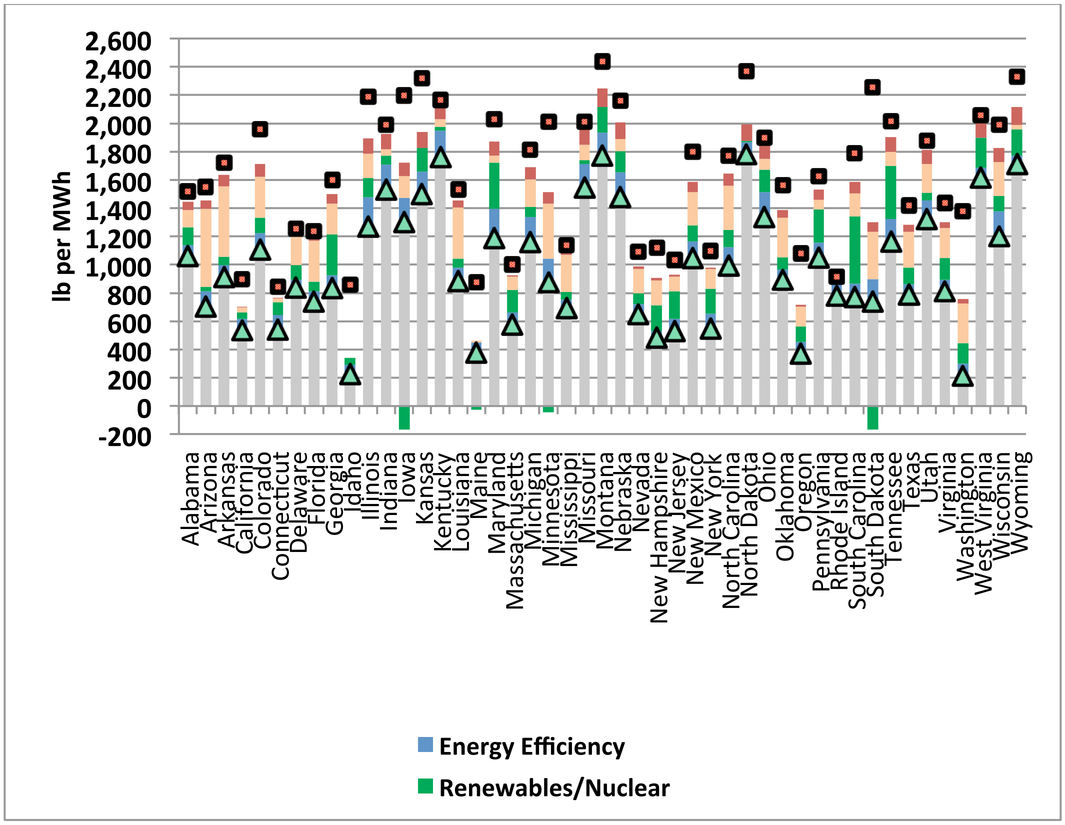
Under the proposed rule, the EPA affords states considerable flexibility in how they comply with the CPP. For instance, states can choose to

- Use trading and other market-based instruments to capture cost-effective mitigation across sources;
- Convert the target rate (lb./MWh) to a mass-based equivalent (tons), if they find that more amenable to trading and other flexible compliance strategies;
- Develop a multistate approach, with other states in its region for instance, to capture potential cost-effectiveness gains.

In issuing its proposed rule, the EPA sought comment on whether new NGCC units should be included with fossil fuel-fired units in the emissions rates limits.

Figure 1 illustrates how the building blocks identified by the EPA contribute to the calculation of each state's emissions rate goals.

Figure 1. Contributions of EPA building blocks to state emissions-rate goals



Source: Authors' calculations based on U.S. EPA (2014c), Appendix 5.
Note: Contributions of building blocks toward state goals are calculated off of the 2012 emissions rate of existing sources, including renewables and affected nuclear units. These contributions account for the gap between the 2012 fossil rate in Figure 1 that considers only fossil sources and the starting point for the building block contributions.

Emissions Trading under the CPP: Rate-based and Mass-based Approaches

The basic premise of emissions trading is that an entity subject to an emissions obligation can comply with that obligation by reducing emissions in its operations or by buying credits (sometimes called allowances) from entities that reduce emissions below their limit. This form of trading across sources allows less expensive mitigation to substitute for more expensive mitigation, thereby reducing the total cost of achieving any given emissions target. These gains from trade increase the cost-effectiveness of compliance while giving all parties an incentive to further reduce emissions. This outcome is why trading has been used for a wide range of pollution control problems worldwide.

Trading under either a rate-based system or a mass-based system can yield cost-effectiveness but do so in subtly different ways.

Rate-based Trading

- Rate-based trading guarantees the target rate is met overall, but individual plants can deviate from the rate by trading credits.

- Units operating below the emissions rate goal can sell credits for each hour they generate and are effectively "subsidized" by receiving emissions market revenue in addition to power market revenue.
- To meet the emissions rate goal, units operating above the emissions rate goal can buy credits from those units operating below the goal and are thereby "taxed" through payments into the emissions market for every MWh generated.
- It is usually assumed that these credits are exchanged entirely within the industry, meaning that states have no opportunity to raise revenue by selling allowances to regulated firms.

Mass-based Trading

- Mass-based trading guarantees an absolute emissions cap across the system.
- All units are effectively "taxed" in proportion to their emissions through allowance purchases for every MWh they produce.
- At the outset of trading, states must decide how to allocate allowances to those units needing them for compliance.
    - States can sell allowances through an auction in which they can raise a substantial amount of revenue. Within the state's discretion, these revenues can be used to compensate parties for higher power costs, to invest in low-carbon technologies and energy efficiency, or to address state fiscal requirements.
    - States can issue the allowances for free to regulated entities, thereby eliminating the direct outlay for allowance purchases.
    - Whether auctioned or given for free, allowances can be resold into an allowance market. Therefore, in either case, the price of electricity can be expected to increase to reflect the price of giving up allowances (an opportunity cost) for every megawatt generated. Electricity bills may therefore increase unless allowance value (auction revenues or free allowance allocation) is redirected to customers to compensate them for higher prices or if allowance revenues are used to subsidize energy efficiency that keeps demand (and prices) down.

By and large, a mass-based approach adds more flexibility to the system than a rate-based approach in that higher-emitting plants that are cheaper to operate have more room to run, so long as they purchase a corresponding level of emissions allowances from other entities.

Methods

Policy scenarios are analyzed using the Dynamic Integrated Economy/Energy/Emissions Model (DIEM), developed at Duke University's Nicholas Institute for Environmental Policy Solutions (Ross 2014a, 2014b). DIEM includes a macroeconomic or computable general equilibrium (DIEM-CGE) component and an electricity dispatch component that provides a detailed representation of U.S. regional electricity markets (DIEM-Electricity). For this analysis, DIEM-Electricity is run as a stand-alone model, implying that electricity demands are fixed at their future forecast levels aside from any considerations for energy efficiency, which is standard treatment for U.S. EPA policy analysis (U.S. EPA 2013). Given the policy in question, this approach facilitates interpretation of the model's insights.

Broadly, DIEM-Electricity is a dynamic linear-programming model of U.S. wholesale electricity markets with intertemporal foresight regarding future market conditions and electricity policies. It represents intermediate- to long-run decisions about generation, electricity transmission, capacity planning, and dispatch of units. To estimate policy impacts, the model minimizes the present value of generation costs (capital, fixed operating and maintenance or O&M, variable O&M, and fuel costs) subject to meeting electricity demands, reserve margins, and any policy constraints. Existing generating units, which were identified from data in the National Electric Energy Data System (NEEDS) database v.5.13 (U.S. EPA, 2013), are aggregated into model plants on the basis of their location, characteristics, and equipment configurations to reduce the dimensionality of the mathematical programming problem.[1] New plant options are included using costs and operating characteristics from *Annual Energy Outlook 2014,* or AEO (U.S. EIA 2014a). In addition, AEO forecasts provide annual demand and fuel price forecasts.

Plants in the model are dispatched on a cost basis to meet demand within each region through 2050. The version of DIEM-Electricity used in this analysis includes 40 electricity markets, defined along the 48 continental U.S. state lines. These regional boundaries and associated state electricity demands are developed from a combination of the U.S. EPA's Integrated Planning Model (IPM) unit and transmission data (U.S. EPA 2013), AEO regional forecasts, and state-level demand data from the State Energy Data System or SEDS (U.S. EIA 2012). Within each region, hourly load duration curves from the EPA (U.S. EPA 2013) are aggregated to show the amount of electricity demand in a number of load "blocks." These blocks convert annual electricity demands from the AEO into subcomponents to capture the non-storable nature of electricity within a year.

The model has multiple compliance options to meet the CPP policy targets designed to reduce CO_2 emissions, all of which are endogenous choices within the model (i.e., the model can choose whichever options are the lowest-cost responses to the policy). These choices cover all four of the building blocks used by the EPA to define state emissions rate goals. First, the model can have coal plants improve their efficiency (their heat rates measured in terms of Btus of fuel burned per kilowatt hour of electricity generated).[2] Second, the model can redispatch generation from higher-emitting sources such as existing coal plants to lower-emitting sources such as existing NGCC plants that may not be running at full capacity, assuming this is cost-effective policy response. Third, the model can specify construction of new low- or zero-emitting sources to reduce CO_2 emissions.[3] And fourth, DIEM can make endogenized choices related to energy efficiency, which can reduce electricity demand and count toward state emissions-rate goals under the CPP.

Some of these compliance options have long been characterized in electricity dispatch modeling, but improvements in coal-plant heat rates are a relatively new option in this type of modeling. Engineering data, notably a report by Sargent and Lundy (2009), tend to show that efficiency improvements are relatively cost-effective. In many cases, these improvements can be economically justified even in the absence of new CO_2 policies, leading to the question of why plants are not undertaking them without GHG policy stimuli.

Historical data show that existing coal units operate under a wide range of heat rates. However, data are insufficient for researchers to determine how heat rate efficiencies are affected by the available engineering options discussed in reports such as Sargent and Lundy (2009). In the absence of this information, DIEM follows an approach similar to Burtraw et al. (2011) and assumes that units with high heat rates have the full range of improvement options shown in Sargent and Lundy (2009), whereas units with low heat rates have no additional improvements they can undertake. In contrast to the EPA analysis (U.S. EPA 2014d) that assumed a 6% improvement was available to all plants for $100/kW in the CPP policy scenarios (but not the EPA baseline), the approach in DIEM implies that a more limited set of plants have heat rate improvement options available that are in the 2%–3% range. These options are

[1] Data from U.S. EIA (2015) are added to account for recent construction and retirement decisions.
[2] They can also switch among 20 types of coal, defined across production locations, coal characteristics, and carbon content, a flexibility that has the potential to reduce carbon emissions by several percent. Biomass and natural gas co-firing are not allowed as options in the baseline or measures that count toward CPP policy goals.
[3] It is assumed that new nuclear plants do not count toward the calculation of emissions rate goals.

available in DIEM in both the baseline and policy scenarios, in which average realized costs to plants that choose to install the measures based on their economics tend to run in the neighborhood of \$50–\$60/kW.

The model can select energy efficiency measures in both the baseline and policy scenarios if they are a cost-effective alternative to generating the same amount of electricity within the electric sector. First-year costs and lifetimes of the measures are based on EPA data, which assume an initial cost of \$770/MWh for most years of the policy and an average lifetime of 10 years (U.S. EPA 2014d). The quantity of efficiency measures available is, in most years, sufficient to reduce electricity demand by 1.5% from the previous year's demand, before consideration of annual demand growth that also occurs in the current year. Following the EPA method, it is also assumed that utilities and program participants equally split the costs of the measures. As a general rule, at those costs the model finds that it is cost-effective to adopt the efficiency measures in both the baseline and policy scenarios, the implications of which are discussed in the results section.

Policy Scenarios

The CPP policy scenarios in this paper focus on the emissions goals defined as Option 1 in the illustrative analysis in the EPA's regulatory impact analysis (RIA) (U.S. EPA 2014d). These options define an interim goal that must be met on average over the 2020–2029 decade. For 2030 and later years, the final goal described in the EPA's calculations must be met in each five-year time period in the model. This analysis examines these emissions goals using both the rate-based approach defined in the RIA and the comparable mass-based approach defined in the EPA's translation of state-specific rates to mass equivalents (U.S. EPA 2014f).

These goals are used to define four main sets of policy scenarios:

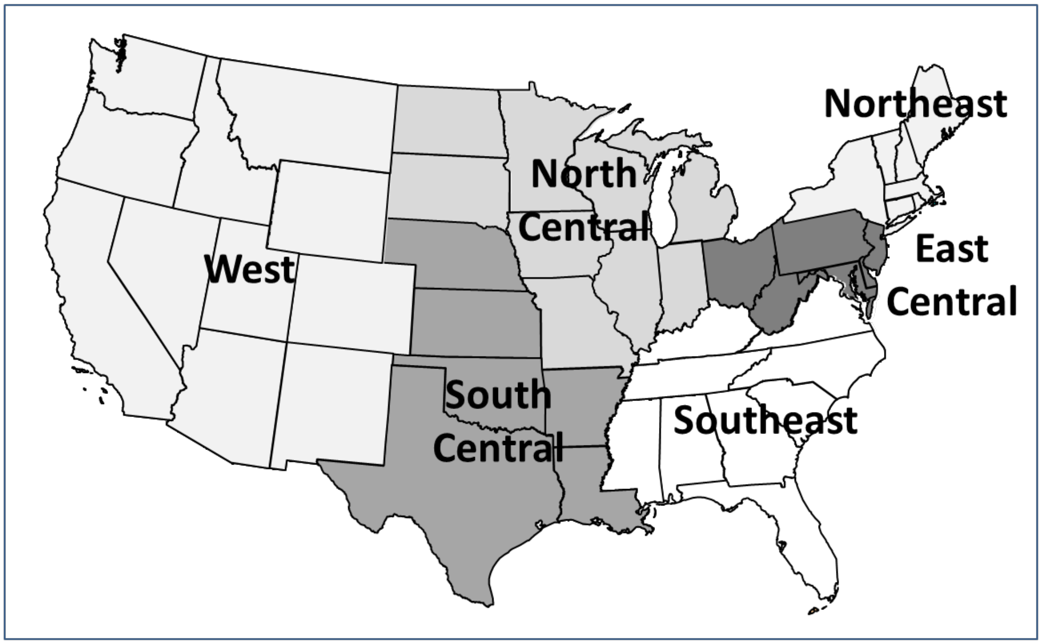
- Rate-based trading among existing fossil units ("Rate"), in which the state emissions-rate goals shown in Figure 1 are applied to emissions from affected fossil sources, which include existing fossil steam boilers larger than 25 MW, existing NGCC units larger than 25 MW, and combustion turbines larger than 25 MW that run at a capacity factor greater than 33% and that generated more than 219,000 MWh in 2012.[4]
- Mass-based trading among existing fossil units ("Mass"), in which the state mass goals calculated by the EPA are applied to the same universe of affected fossil sources.
- Rate-based trading including new NGCC ("Rate with New NGCC"), in which the state emissions-rate goals from the "Rate" scenario are also assumed to apply to new NGCC units. Bringing these units into the trading system will tend to loosen the policy as new combined cycle units have emissions rates of approximately 750 lb./MWh, which is below the rate goals of some two-thirds of states.
- Mass-based trading among existing fossil units ("Mass with New NGCC"), in which the EPA-calculated state mass goals, including an adjustment for new NGCC units, are used. The calculation of these goals assumes that future electricity demand growth is met in states through construction of NGCC units.

Each of these four sets of scenarios is examined using three alternative assumptions about the geographic scope of trading among covered sources.[5] First, it is assumed that states act alone to meet their individual state emissions goals (referred to as "State"). In this case, the emissions rate or mass must be met through actions in each state without engaging in any trading of emissions allowances with other states, although

[4] Tribal units are excluded from the policy.
[5] Rather than attempt to predict which states or regions are likely to choose which approach, the analysis assumed that all regions of the country follow the same rate-based or mass-based approach to the CPP with the same method of allowance trading.

this assumption does imply fully efficient trading of obligations within each state. Second, it is assumed that states group together to form trading blocks in order to take advantage of any cost savings that can be achieved through trading obligations with states that possess lower-cost methods for meeting the regional goals (referred to as "Regional"). Figure 2 shows these regional groups, which generally follow the zones defined in the EPA's RIA (U.S. EPA 2014d) with the exception that Virginia is considered part of the Southeast region based other work conducted at the Nicholas Institute. To evaluate the potential cost savings of extending the regional approach to allow trading among all states, the policy cost impacts of national rate-based and mass-based scenarios are also presented (referred to as "National").

Figure 2. Regional trading blocks



Third, it is assumed that when states act together to meet emissions goals they keep their originally defined state goals and work to meet a regional emissions target that is the generation-weighted average of the state goals. In the case of rate-based goals, this approach will tend to incentivize some shifting of the generation mix as states attempt to take advantage of looser emissions rate targets in some states than in others. It is unclear if this approach would be allowed under the CPP, but it also seems unlikely that states with looser goals initially would agree to enter into regional trading agreements if it meant adopting a tighter regional-average rate goal.

After the four sets of policy scenarios are covered, the modeling is also extended to include sensitivity analyses of renewables, energy efficiency, and natural gas prices. Examining possible alternatives for these three critical factors in meeting states' goals helps illustrate some important drivers in the CPP policy and in the DIEM model's findings.

Results

The analysis begins with an examination of the generation impacts of CPP under the four main policy scenarios. Generation changes are a useful metric to summarize the overall implications of changes in availability capacity through retirements and new construction as well as the utilization rates of plants. Fuel demands will also largely follow these generation patterns. The analysis then explores new capacity and utilization rates, along with the overall effects of the CPP on U.S. emissions of CO_2. Subsequently, it looks at policy costs under the alternatives and explores some of the variation in regional impacts.

For brevity, the industry-wide results focus on CPP consequences when using regional trading of allowances because changes in generation tend to follow similar overall patterns, regardless of whether states choose to engage in regional trading or act alone to meet emissions goals. However, the sections of the analysis related to policy costs explicitly differentiate among the three sets of assumptions about the geographic scope of allowance trading because there can be larges cost differences if location-based (i.e., "where") flexibility in the policy responses is constrained

Generation

Total generation across the United States for the four categories of plants most affected by the policy—existing coal and NGCC, new NGCC, and existing plus new renewables (excluding hydroelectric and biomass)—is shown in Figure 3 for 2020 and 2030, representing the initial year of the policy and the year in which it is in full effect. To place the DIEM model results in context, the figure shows baseline generation in DIEM as well as results for the regional allowance trading option from both DIEM and the EPA analysis conducted for the CPP RIA (U.S. EPA 2014d). In examining the baseline and policy generation in this, and subsequent, figures, DIEM is allowed to choose the energy efficiency measures defined by the EPA, if it is cost-effective to do so, and does choose to fully adopt these measures at the prices defined by the agency, assuming a 50-50 cost split between utilities and consumers. This means that electricity demand in the baseline forecast and all policy cases is roughly 3% lower than AEO forecasts in 2020, 8% below AEO forecasts in 2025, and 11% below AEO forecasts by 2030.

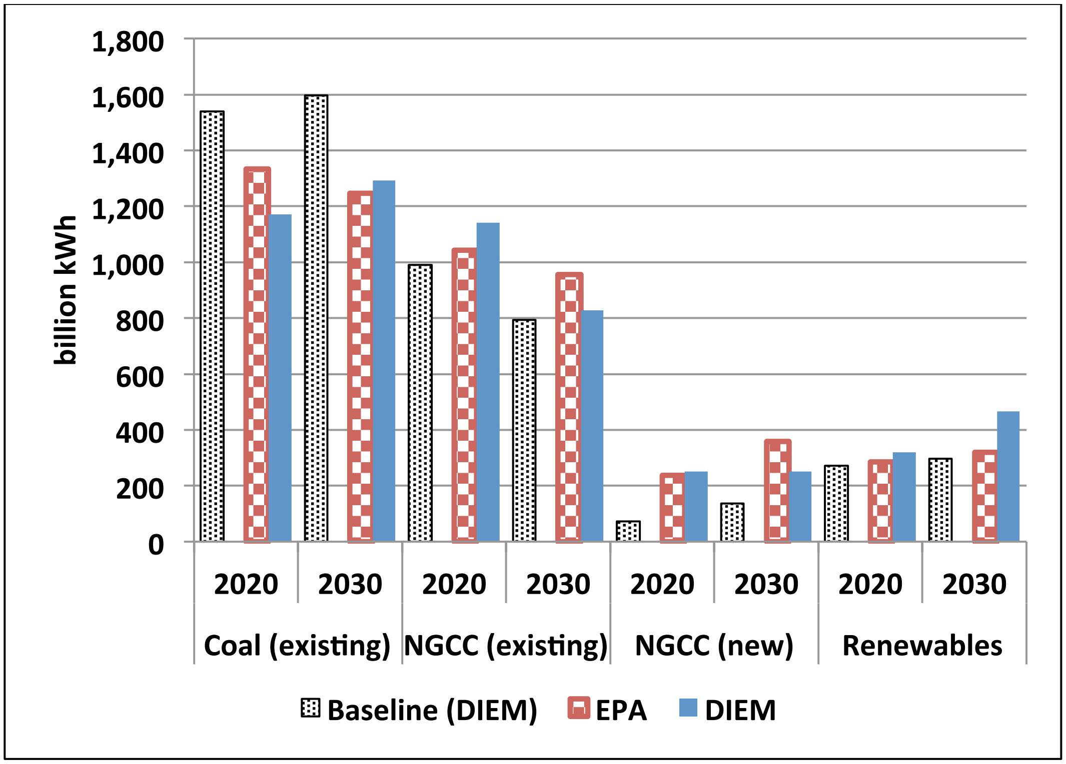
Under a regional rate-based approach, coal generation drops fairly significantly when the policy takes effect in 2020, although it does recover over time. Part of the drop comes from retirement of an additional 29 GW of coal in response to the CPP from baseline levels of 245–250 GW (after accounting for both existing policies such as MATS and the lower demand from energy efficiency savings in the baseline).[6] The rest of the 2020 decline in coal and subsequent recovery comes from changes in utilization rates, as shown in Figure 3.

The incentive structure implicit in the CPP emissions-rate calculation tends to encourage generation by existing NGCC units, which have a lower emissions rate than coal units, and by zero-emitting renewables such as wind and solar. Although the model solution does not consider it economic to redispatch from coal to existing gas units at the 70% rate used in the CPP building block calculation of the state emission rate goals, generation from existing NGCC units does increase in the early years of the policy. By 2030, construction of additional renewables has offset the need for this existing gas generation, which occurs to a larger degree in the DIEM analysis than in the EPA analysis.[7]

[6] Existing NGCC units do not tend to retire under a rate-based approach to the CPP, although some retirements occur by 2030 under the mass-based alternatives.

[7] DIEM uses average improvement rates in renewables costs based on the Electric Power Research Institute's US-REGEN model (Blanford et al. 2014), which occur somewhat more quickly than those in EPA's IPM model. Over the 2015–2030 period, the authors' calculation of these average improvement rates in capital costs for onshore wind average 0.91% per year, compared with EPA's 0.73% per year. Over the same time frame, solar photo voltaic costs in DIEM based on these calculations improve 2.38% per year, compared with the EPA's 1.16%.

Figure 3. U.S. generation under rate-based regional trading



Note: Renewables excludes hydroelectric and biomass sources.

Under the CPP, constraints are imposed on existing coal and gas units affected by the policy, providing an incentive for a quicker shift into new NGCC generation than would be the case in baseline forecasts. This effect appears as the expansion of new NGCC generation shown in Figure 3. Both the EPA and DIEM analyses show this effect occurring in the industry, although by 2030 the DIEM analysis reveals a shift from meeting future increases in electricity demand with new NGCC generation to meeting future demand through new renewables, which are incentivized under a rate-based approach to the CPP.

Figure 4 contrasts this rate-based CPP option with the mass-based alternative for existing units specified by the EPA (U.S. EPA 2014f).[8] Although this mass-based option also tends to shift generation out of covered units and into new NGCC units, a mass-based approach removes the extra incentives for new renewables and any existing gas units emitting at rates below those defined in the states' emissions rate targets. Under a mass-based approach, all emissions from existing, affected fossil fuel-fired units are "taxed" in proportion to their total carbon content, as discussed above.

Perhaps counter-intuitively for a mass cap on CO_2 emissions, coal generation is higher initially than under the rate-based approach. This is the case for a couple of reasons. First, the mass-based approach adds flexibility to the policy by allowing any declines in overall existing fossil fuel generation to help meet the policy goals; by contrast, any such declines without an accompanying improvement in system-wide emissions rates does not help meet the rate-based scenario goals. Second, because a mass-based option does not incentivize use of existing NGCC units, the decline in their generation must be made up somewhere else. Finally, the additional flexibility of a mass-based approach lowers the per-ton cost of

[8] Examination of these results, and those for other scenarios, should be made with the understanding that the alternatives are not necessarily achieving the same levels of emissions, which makes direct comparisons across the options difficult.

CO_2 emissions, as discussed below, making coal units cheaper to operate under this approach than under a rate-based approach.

Under the mass-based approach, as under the rate-based approach, it is cost-effective to speed up construction of new NGCC units that are outside of the CPP policy in order to offset the declines in generation by coal and existing NGCC units.[9] As shown in the results, a mass-based approach removes the extra incentives provided by the CPP to new renewables by the rate-based approach, which leaves renewables at levels close to those of the baseline forecast in the model. Another implication of these results is that it is cheaper at the natural gas prices in the AEO forecasts to build new efficient NGCC units than to move more generation into renewables.

Figure 4. Regional rate-based versus regional mass-based trading among existing units

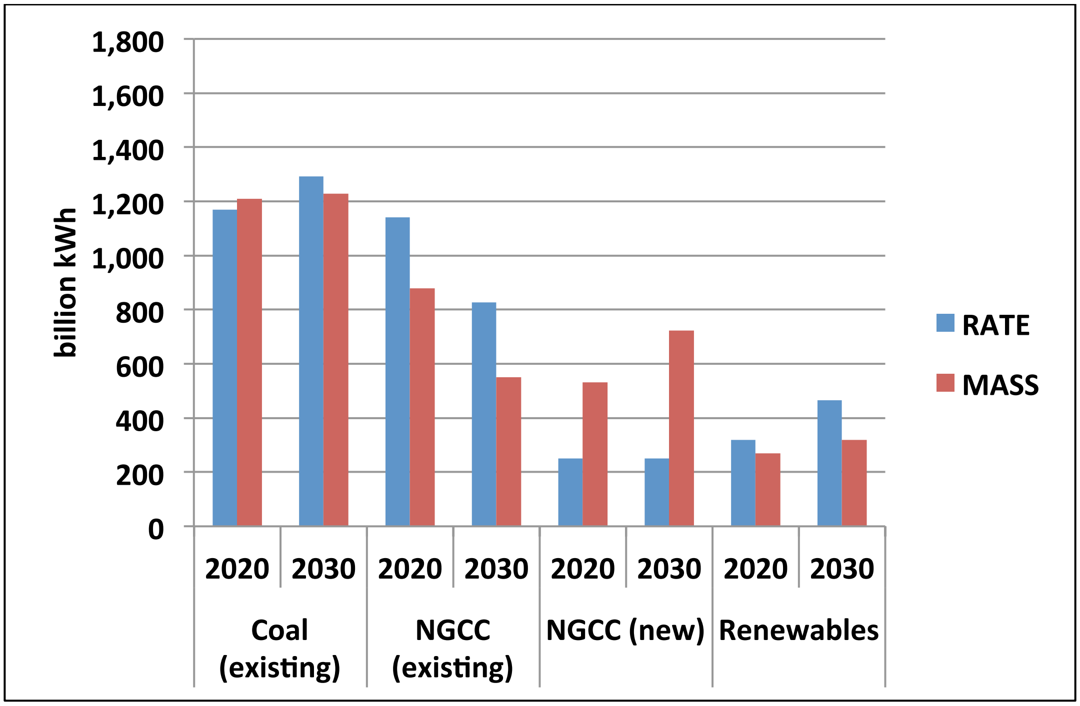
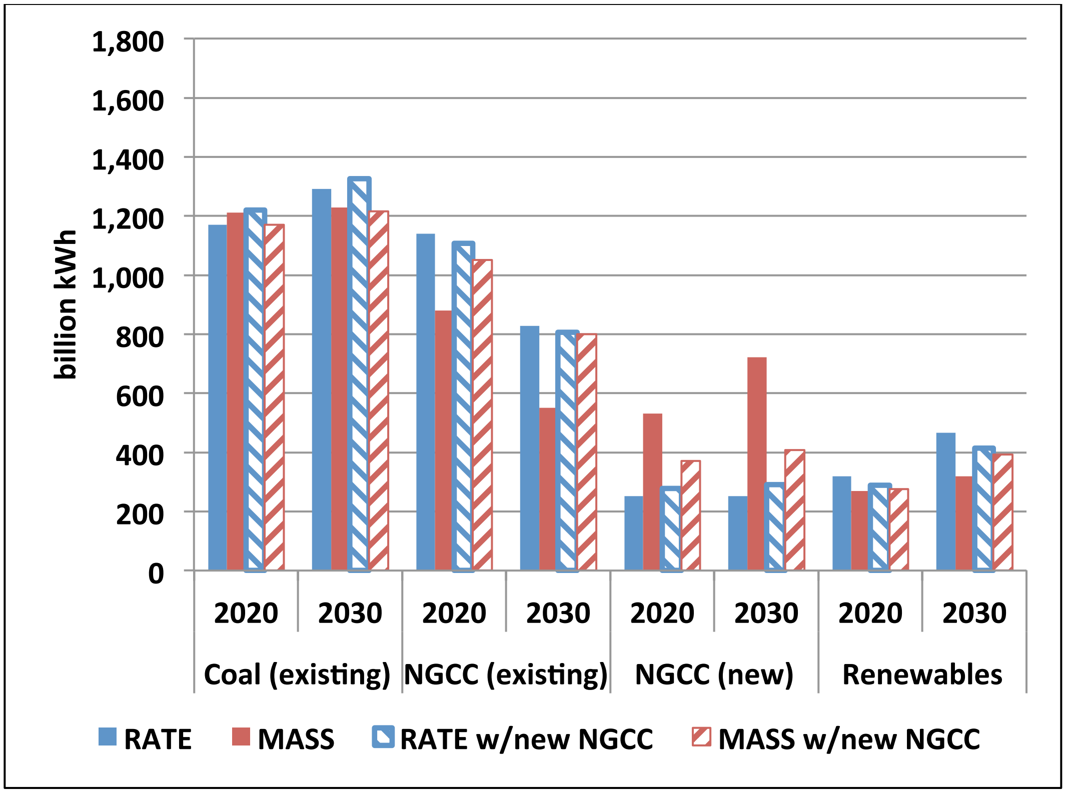


Figure 5 examines the implications of bringing new NGCC generation under the CPP policy to avoid a situation in which only emissions from existing NGCC units are covered. Given that the emissions rate goal is not adjusted in setting the policy targets in the Rate-based with New NGCC model runs, and the mass goals are taken from EPA calculations, the four alternatives are not directly comparable in terms of the emissions outcome they achieve. However, in spite of these definitional differences, the implications of rate and mass are similar when new NGCC units are brought into the policy – mass-based compliance still favors new NGCC generation over existing generation more than rate-based compliance does; however, the effect is not as strong when new NGCC is now subject to the emission limits. Renewables don't receive quite the same level of subsidy as they did in the previous rate-based model runs, but they are incentivized to some degree as a zero-emissions generator under a policy that covers almost all emissions from fossil fuel-fired units once new NGCC is covered.

[9] Total construction of new NGCC units by 2050 is relatively similar across a model baseline without energy efficiency measures and either the rate-based or mass-based approaches. Thus, the CPP policy largely tends to speed up construction of units that would have occurred regardless (assuming the need for this additional generation is not removed by energy efficiency measures).

Figure 5. Regional rate-based versus mass-based trading with new NGCC generation



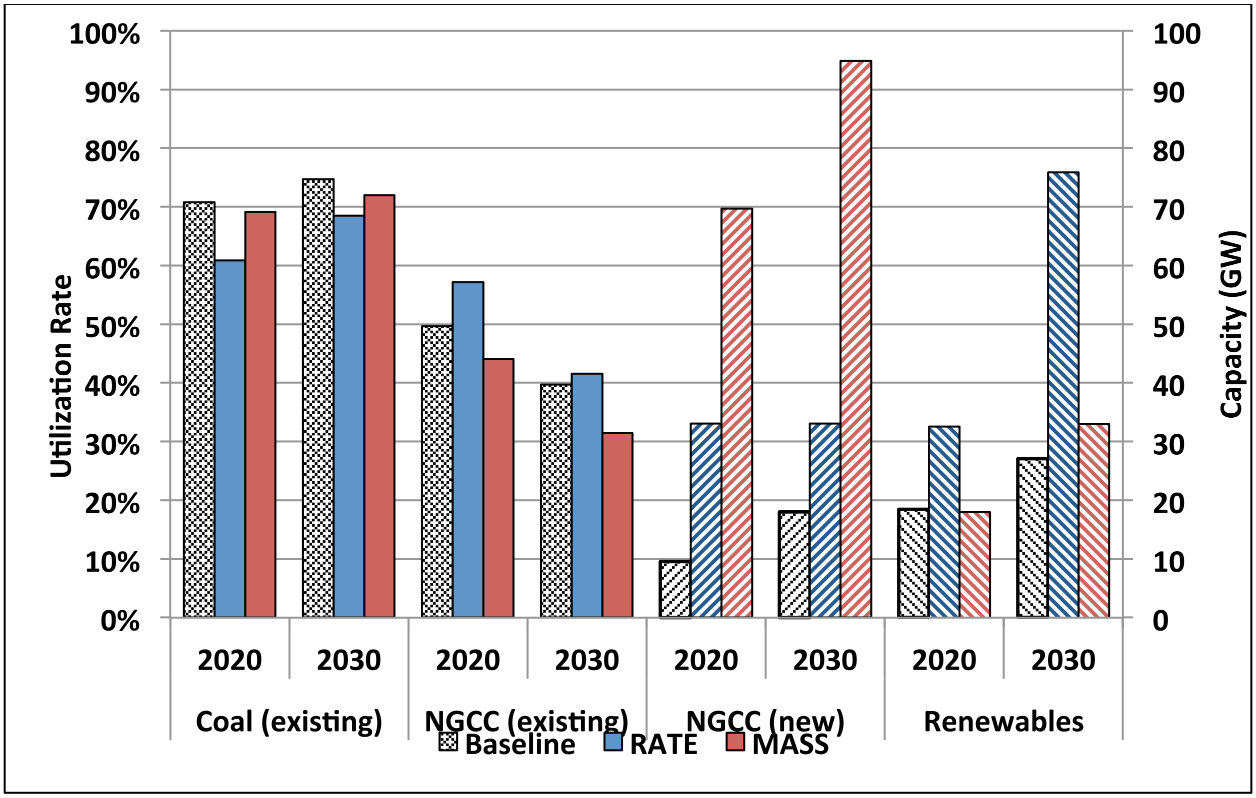
Capacity and Utilization

Changes in generation cover much of the adjustments in the industry in response to the CPP, but it is also useful to examine how the policies can change outcomes such as capacity utilization and new construction of different categories of generation. The left-hand side of Figure 6 shows how utilization rates for existing coal and NGCC units changes, while the right-hand side shows total cumulative construction of new units. The redispatch of coal into existing gas units can be clearly seen in the rate-based results but disappears under the mass-based option that does not incentivize this shift. Coal utilization rates are affected more significantly in 2020 in the rate-based option, although this result is in part a function of retirements and the behavior of remaining units. By 2020, there are 29 GW of coal retirements under the rate-based scenario and 48 GW under the mass-based scenario, implying that the higher coal utilization rates under the latter are coming from retirement of more inefficient coal units.[10]

Construction of new units, measured in gigawatts, is significantly different between the rate-based and mass-based options. Rate strongly favors renewables compared to mass, which emphasizes new NGCC units (assuming they are not covered by the CPP policy). Because renewables have utilization rates that average 30%–35%, their level of construction is not directly comparable in generation terms to the new NGCC units that tend to run as baseload units in the model at the maximum availability rate of 87%.

[10] No retirements of existing NGCC units occur under the rate-based scenario. Under the mass-based approach, nearly no existing NGCC retirements occur in 2020, but 28 GW of NGCC capacity goes offline by 2030.

Figure 6. Existing-unit utilization rates and new capacity under regional trading



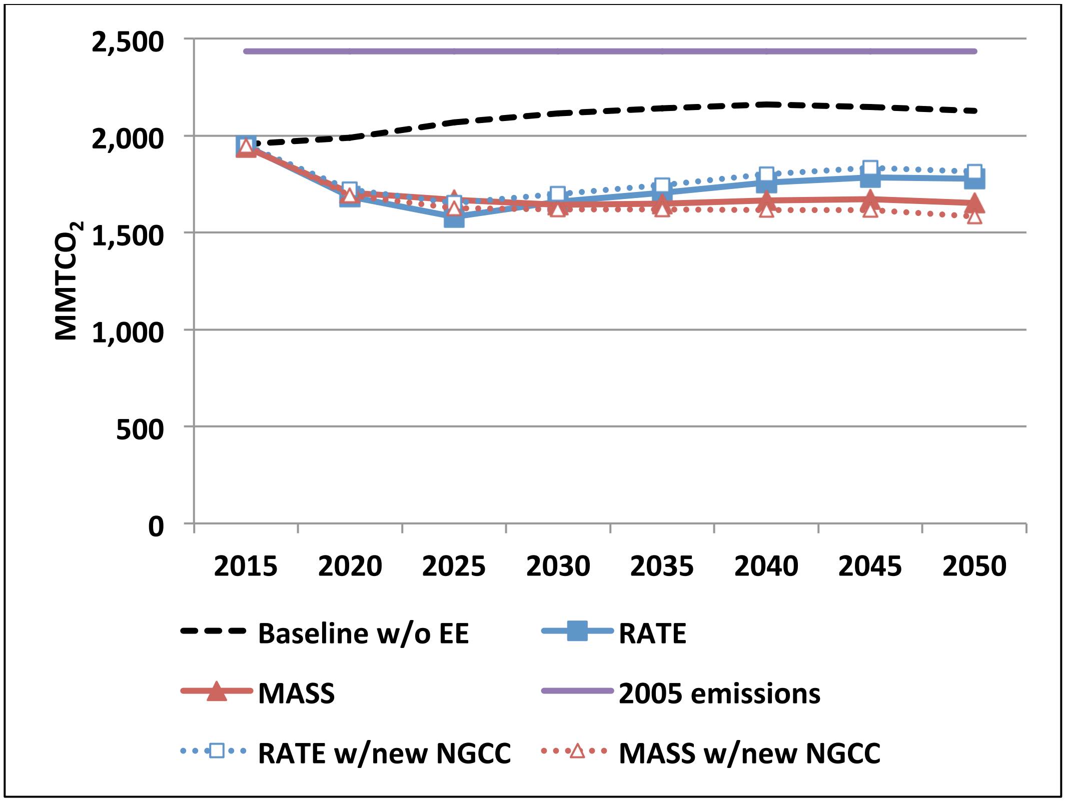
Emissions

Because the main goal of the CPP is to reduce emissions from electricity generation, it is important to examine the policy's short-run and long-run emissions consequences. Figure 7 shows trends in emissions for the rate-based and mass-based approaches and compares them to baseline emissions (without energy efficiency measures) and the sector's emissions in the year 2005 of 2,434 $MMTCO_2$ (U.S. EPA 2014d).

The first decade of the policy begins and ends with similar emissions for both approaches when new NGCC generation is not included in the regulation, which represents a 32% decline in emissions from 2005 levels and a 22% decline from expected baseline levels.[11] Both approaches allow for growth in emissions after 2030 because they do not cover emissions from new NGCC generation, but the rate option also allows for growth in total emissions from covered units as electricity demand grows. As indicated, an increase in emissions under the rate system follows the same trend as the baseline forecast. Because a rate-based approach targets the emissions rate of covered units instead of their total emissions, it is possible for emissions to rise fairly substantially under that approach compared to a mass-based approach, which puts a cap on emissions. By 2050, rate-based emissions have risen 5% over 2020 levels, while mass-based emissions have fallen by an additional 3%. As shown by the dashed lines, inclusion of new NGCC units in the CPP does not dramatically affect total emissions for the assumptions adopted in this analysis.

[11] The decline in emissions from the CPP compared to a baseline that includes energy efficiency measures is approximately 15% in 2030, implying that changes in generation patterns from the policy account for roughly one-half of the emissions decline.

Figure 7. U.S. emissions under regional trading



Policy Costs

"Policy costs" encompass the policy's effect on all costs associated with delivering electricity to meet grid demands in a particular state or region. Among these costs are those directly related to generating electricity in an area: capital costs of new construction or retrofits (typically annualized for cost-reporting purposes), fixed operations and maintenance (O&M) that represent annual maintenance expenditures, variable O&M that are costs which vary with the level of generation, and fuel costs. Other types of costs such as carbon allowance payments affect generation decisions in the model, but for cost-reporting purposes they are simply a transfer among agents in the economy and do not represent a net cost to society as a whole. Therefore, they are not reported as part of a policy's national-level costs, though the costs of the emission-reducing actions that they incentivize are. When interpreting cost results, it is also important to remember that the DIEM model is minimizing costs for the nation as a whole over the entire 30-year book life of new units installed in 2060. This long-term approach to cost minimization can lead to policy costs in the short term that move counter to long-term trends.

From a state or regional perspective, additional costs and benefits are associated with importing or exporting electricity. Reported policy costs in this analysis assume electricity trade is valued at the wholesale electricity price prevailing in the exporting state or region during the load demand block in question. From a subnational viewpoint, costs and benefits can also be associated with importing or exporting CPP allowances to other states under regional trading schemes. Neither of these types of state trade flows affect national cost minimization, but both need to be evaluated to determine local policy costs. Costs of energy efficiency measures paid by both utilities and consumers also must be factored into cost reporting.

As a general rule, flexibility in any form will always lower costs as power producers seek out cost-effective responses to the policy. The building blocks in the CPP provide several cost-lowering forms of flexibility: states can count energy efficiency measures and renewables toward compliance under rate-based approaches, convert from rate-based to mass-based goals and, importantly, the ability of states to act in concert with other states to take advantage of low-cost reduction options across regions (locational or "where" flexibility). During the first decade of the policy, states can also smooth adjustments over time (temporal or "when" flexibility) as they move toward the final emissions goals in 2030. Because DIEM operates with foresight, construction decisions will be optimal as producers plan for future needs and take advantage of any available cost-saving flexibility, which will affect policy costs and investment patterns.

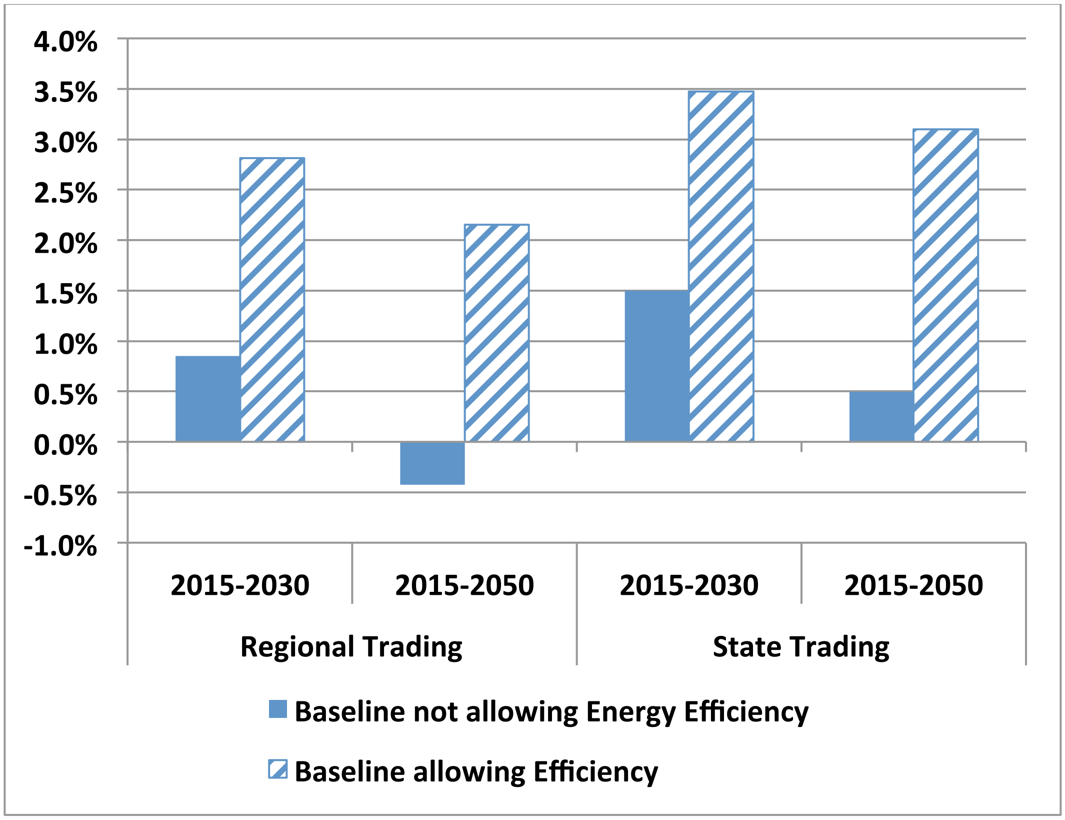
Before comparing policy costs across all the scenario alternatives, it is necessary to determine which elements are considered part of the baseline forecast in the model. As discussed above, the energy efficiency measures included in the modeling are a cost-effective alternative to electricity generation under the parameters given and therefore should be expected whether or not the CPP policy is in place (i.e., in the baseline). That leaves open the question of what are the appropriate baseline costs against which to measure policy costs. Allowing energy efficiency measures into the model's baseline removes their apparent cost savings from being attributed to the policy, and thus these savings are not factored into the incremental costs between the baseline and the CPP policy.[12] As a result, estimated policy costs will be higher than they would be under the alternative assumption that the energy efficiency cost savings are brought about by the policy.

Figure 8 illustrates the magnitude of the energy efficiency attribution effect for regional and state trading of allowances in a rate-based approach to the CPP. Although the modeling is optimizing costs over a longer time horizon (2050 rather than 2030), the results reveal changes in costs (in present value terms) either through the first decade of the policy or through 2050 because decisions may be based on shorter-term implications than those underlying the structure in the model. As the regional trading results show, in the near term the cost savings of energy efficiency measures almost offset all other policy costs, leaving a system-wide cost increase of 0.9% over the 2015–2030 period when compared to a baseline not including energy efficiency measures. Over a longer time horizon (through 2050), these savings more than offset CPP policy costs, which are -0.4% lower than costs in a baseline without energy efficiency measures. Adding the energy efficiency savings into the baseline ("Baseline Allowing Efficiency") results in a cost increase for the CPP with regional trading of 2.8% through 2030 and 2.2% through 2050.

Similar impacts of accounting for efficiency in the baseline are seen for results from the CPP state-trading scenarios. The extra flexibility associated with regional trading lowers policy costs by 20%–30%, depending on the timeframe of interest, compared with the policy costs of states acting alone.

[12] The same is true of allowing coal-unit efficiency retrofits in the baseline, although this occurs comparatively less often in the baseline and has little effect on reported policy costs.

Figure 8. The effect of energy efficiency attribution on the CPP rate-based policy costs (present value over time periods shown)



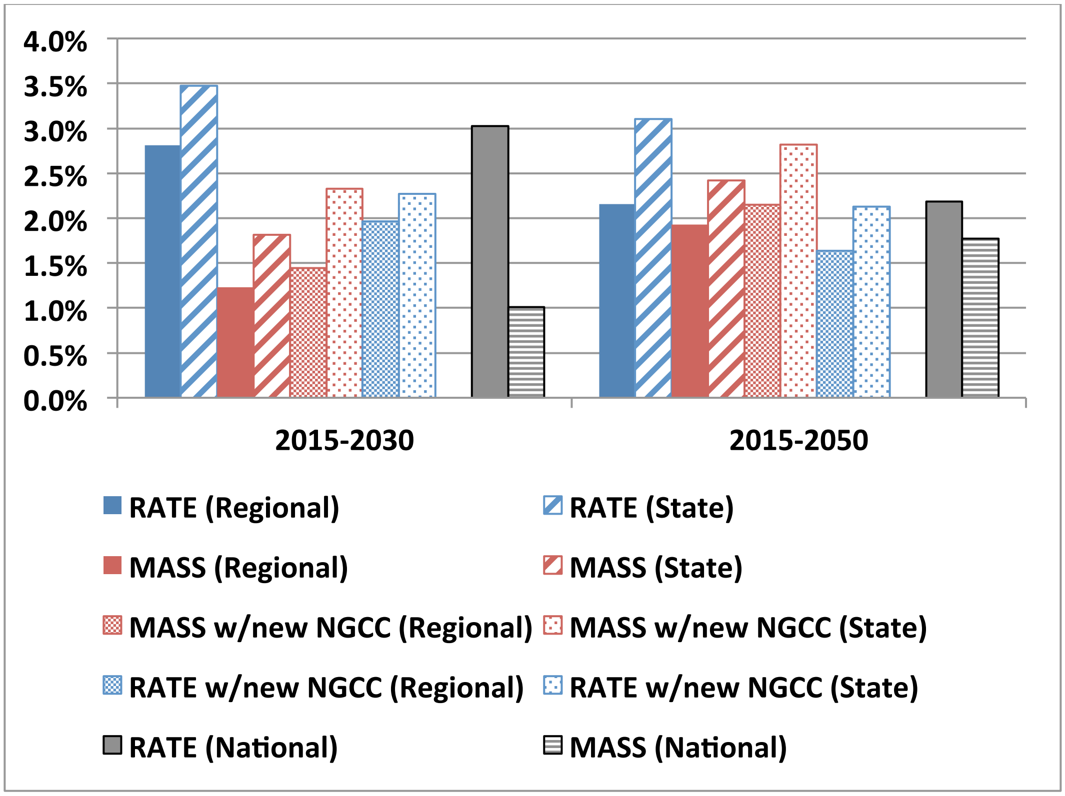
From this point forward, this analysis presents policy costs compared to a baseline that allows energy efficiency measures in order to avoid the need to justify non-adoption of cost-saving measures in the model's baseline run; this logic implies higher policy costs than the alternative assumption.

Figure 9 compares the full range of scenario alternatives across rate and mass, and geographic scope, and over the 2015–2030 and 2015–2050 timeframes. Aside from the cost savings associated with a move from unilateral state action to regional trading, savings can be realized through a switch from a rate-based to a mass-based system. In the early years of the CPP, this switch results in a cost decrease of more than 50%, although the savings from a mass-based approach are less dramatic when considered through 2050.

Including new NGCC in the CPP lowers the cost of the rate-based approach and raises the cost of the mass-based approach. In the short term (to 2030), however, the mass-based approach is still less costly than the rate-based approach even with new NGCC included in the rule. However, in the long run (to 2050), including new NGCC in the rule may make a rate-based approach slightly less expensive than a mass-based approach, because renewable capital costs, which factor more heavily in the rate-based approach, continually decline.

With a national trading system, the mass-based option achieves some additional cost savings over the regional trading system (which is already lower cost on in-state trading only). For national rate-based trading, the results are less conclusive and actually show higher costs than regional trading for a couple of reasons. First, this analysis's approach to regional trading in which each state keeps its original emissions-rate goal already provides the system with significant flexibility. Second, when we look further out (to 2050), there is no discernable difference between costs with national and regional trading; in fact, over the model's full time horizon (beyond 2050, not shown here), the national rate-based approach has lower costs than a regional approach.

Figure 9. U.S. policy costs for all alternatives with energy efficiency measures included in the baseline (present value)



Wholesale Electricity Prices

The electricity component of DIEM used in this analysis focuses on wholesale electricity markets, rather than retail markets, and estimates wholesale electricity prices on the basis of the marginal costs of electricity generation.[13] How states implement the CPP can have significant impacts on these wholesale prices, although the way costs are passed through to retail customers in regulated markets may counteract some of these impacts.

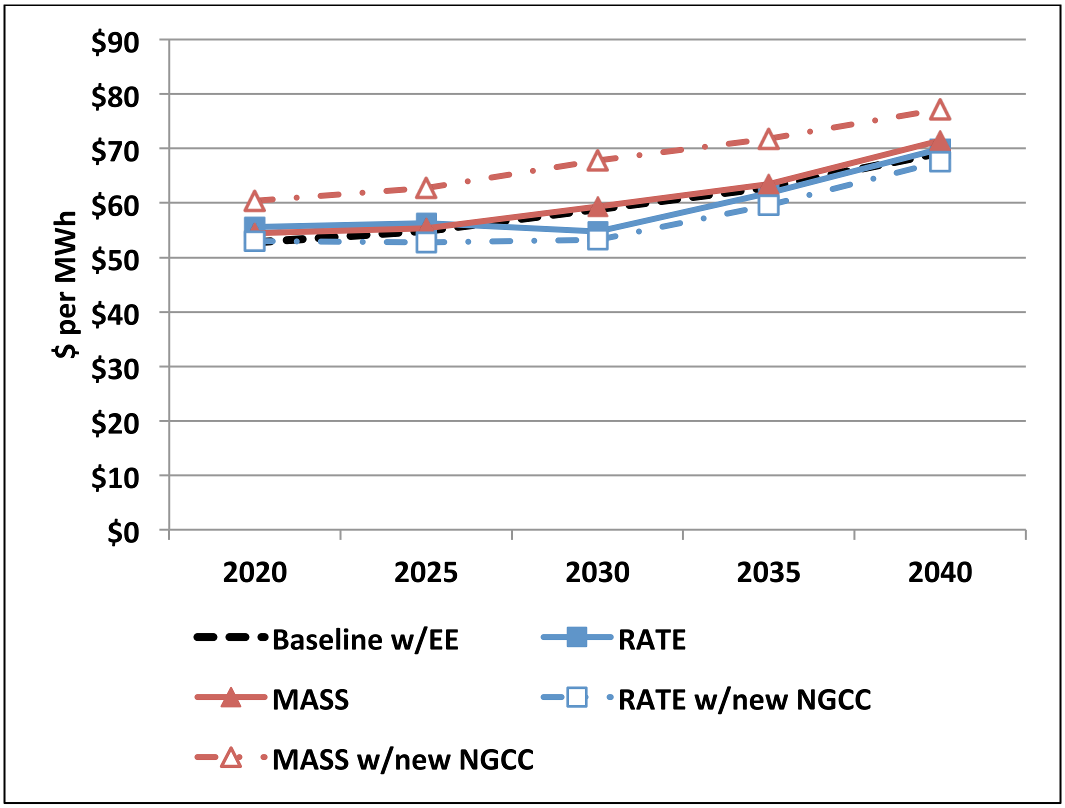
As discussed above, a rate-based approach works to "tax" generating units that emit at a rate above a state's goal and to "subsidize" units that emit at a rate below that goal. Conversely, a mass-based approach will "tax" all units in proportion to their emissions. The implications of these features can be seen in Figure 10, which compares the various scenario electricity prices against a baseline that includes energy efficiency measures, which will tend to eliminate the need for what would have been the highest-cost generating units, thereby lowering the wholesale price in the baseline.

In 2020, both the rate-based and mass-based approaches covering existing fossil fuel-fired units lead to slight price increases, largely driven by the CPP's encouragement of a relatively rapid expansion of new

[13] Technically, wholesale prices are the shadow price on the demand constraint in the model and are available in each region for each time block in the load demand curve. These average prices are generation-weighted averages across regions and time blocks in the model.

NGCC units that are likely to be the high-cost price-setters in the markets. The higher price increase under the rate-based approach (5% compared with 3% under the mass-based approach) is driven by that approach's larger initial adjustments compared with the more flexible mass-based option. By 2030, prices under the mass-based approach are still higher than those under the baseline, but prices under the rate-based approach have declined as the "subsidies" to existing gas units help lower net operating costs for these high-cost units. A larger price decline is seen nationwide (up to $10/MWh in 2030) if a rate-based policy includes new NGCC units, which would be the price-setter in some markets. The most dramatic increase comes with a mass-based policy that includes new NGCC units because both existing and new NGCC units are "taxed" in proportion to their emissions, the costs of which are reflected in wholesale prices.

Figure 10. U.S. average wholesale electricity prices (regional trading)



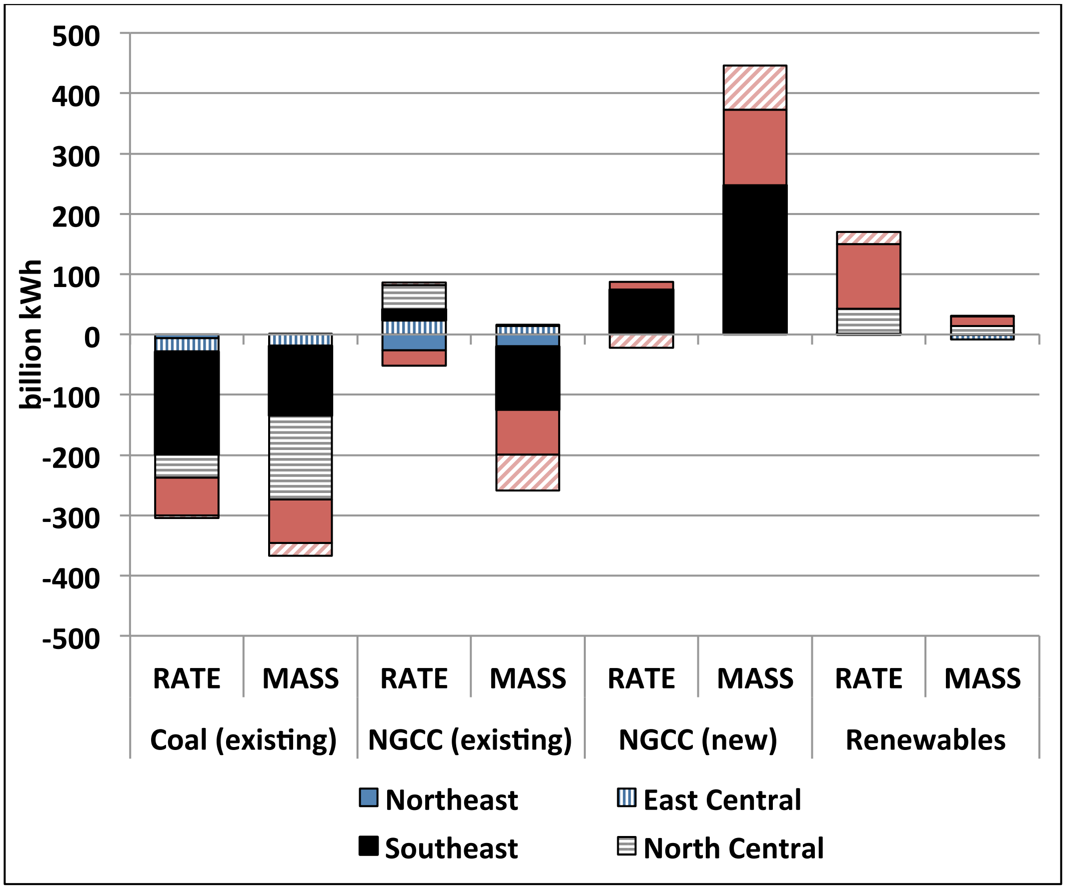
Regional Impacts

This analysis examines how the changes in total U.S. generation are spread across U.S. regions. It also compares allowance prices for CPP credits and policy costs across regions under the rate-based and mass-based options.

Generation

Figure 11 separates the changes in generation by type of unit from Figure 4 into their regional components, thereby showing where the largest adjustments are occurring across the nation under the rate-based and mass-based approaches by 2030. The findings indicate that many of the most substantial fossil fuel generation changes happen in the Southeast: coal generation substantially decreases under both approaches, existing NGCC generation also decreases under the mass-based approach, and the region constructs much of the country's new NGCC generation. In contrast, renewables are relatively unavailable in the Southeast and construction of wind units is concentrated in the middle section of the country (North Central and South Central) and the West.

Figure 11. Generation changes versus the baseline under regional trading (2030)



Allowance Prices

Allowance prices associated with a regional approach to the CPP vary across the nation. These prices, shown in dollars per metric ton of CO_2, reflect the cost associated with the highest-cost option taken in response to the policy, or the action on the margin that just allows a region to meet its emissions goals.

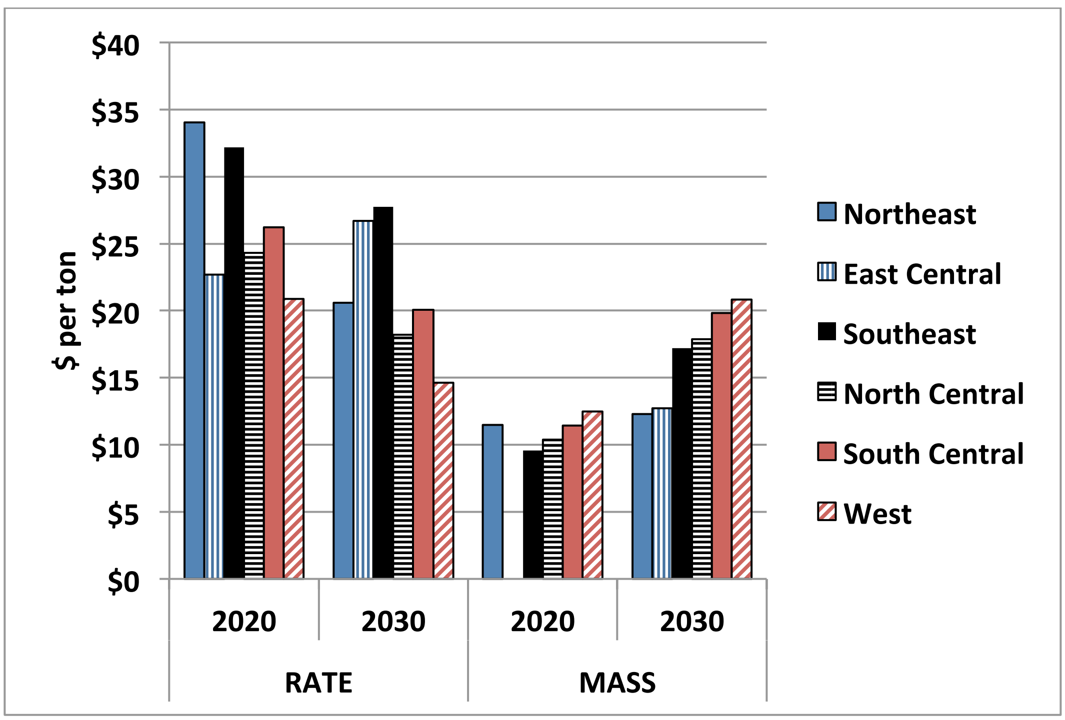
Allowance prices under the rate-based approach and those under the mass-based approach do not have the same meaning. In a rate-based approach, fossil units pay the price only on tons generated by units over states' emissions rate goal and receive this price for any tons generated under the emissions rate goal. Conversely, in a mass-based approach, all affected fossil units pay the allowance price for all tons of emissions, regardless of an individual unit's emissions rate. Across regions (or states within regions), variation in mitigation opportunities, as shown by differences in allowance prices, indicates the potential for gains from coordination.

In the first decade of the CPP, the Northeast and Southeast stand out as regions needing to take the highest-cost actions at the margin to meet regional emissions rate goals (see the allowance prices on the left-hand side of Figure 12). By 2030, the Southeast has taken over as the highest marginal-cost region, followed by the East Central region. In either time period, the West has the lowest rate-based allowance prices for a variety of reasons such as its ongoing construction of renewables and lower dependence on fossil generation.

Allowance prices under a mass-based approach tend to rise toward 2030 as the added flexibility allows states to shift costs farther out in time while keeping costs initially low. Across regions, the pattern of prices for mass-based versus rate-based approaches is fairly different, for example, the West has comparatively low allowance prices under the rate-based approach but has the highest prices under the mass-based approach because further reductions there are more expensive on the margin. In the East Central region, a mass-based policy is not initially binding (price is zero, meaning that the baseline emissions trajectory is already compliant with the CPP), but the policy becomes binding by 2030, yielding a positive price and inducing real mitigation.

There are also very different potential revenue implications for the rate-based and mass-based options. Generally, in rate-based systems, the value of allowances is kept within the industry because units that generate at rates below the goal sell allowances directly to units generating above the goal. For mass-based systems, this is not necessarily the case because governments have the option to either auction or grandfather allowances associated with the policy. Potential revenues at these allowances prices are $20–$30 billion per year nationwide.

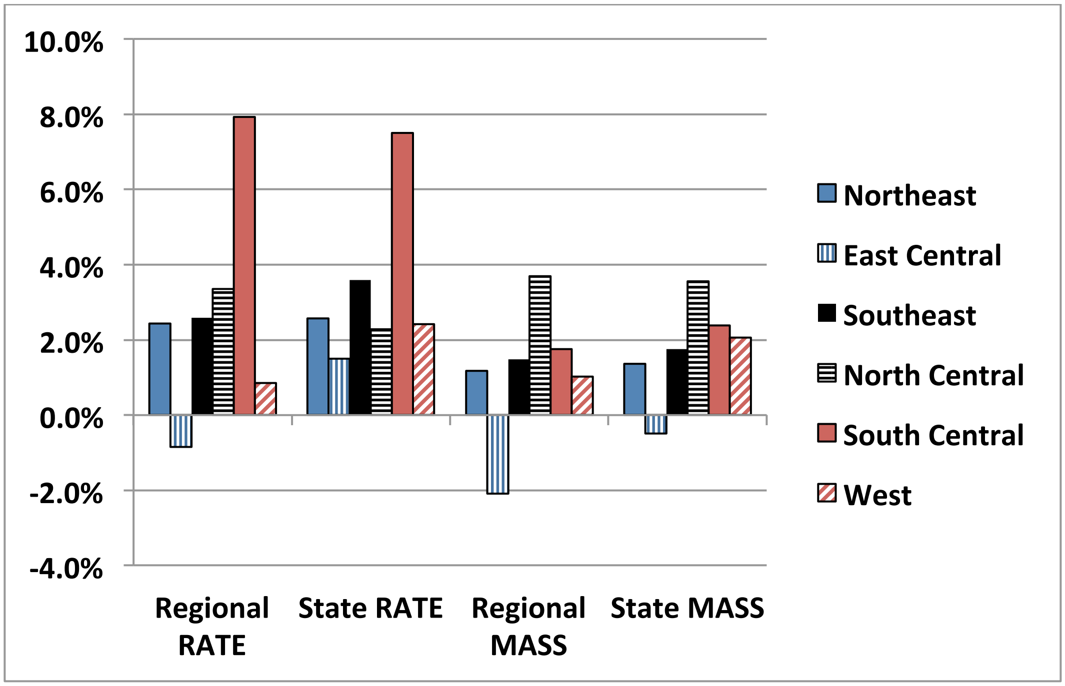
Figure 12. Regional allowance prices under rate-based trading



Policy Costs

Regional costs of the CPP policy depend on a wide range of factors, for example, emissions goals, existing capacity, and renewable-generation construction capacity. As Figure 13 shows for policies covering existing units, allowance prices (i.e., marginal costs) are relatively uniform across regions, especially for a mass-based policy, but total policy costs can vary substantially. The South Central region, which has to construct the most new renewables to meet emissions rate goals, has the highest costs for rate-based options. The West, with enough cost-effective renewables to meet its rate goals, has little need to build new NGCC capacity to offset declines in existing coal and gas generation. The smaller East Central region has negative costs (positive net benefits) through 2030 under both rate-based and mass-based approaches, although, as mentioned in the price discussion above, this effect, a consequence of a nonbinding policy in the short run, disappears as costs beyond 2030 are factored into the calculation.[14] The North Central and West regions are better off under a rate-based approach, while all other regions are better off under a mass-based approach.

Figure 13. Regional policy costs (present value 2015–2030)



Sensitivity Analyses

How generation responds to a policy in a linear-programming model such as DIEM can be contingent on assumptions about future conditions in electricity markets. For the CPP, several critical assumptions are worth exploring to understand how alternative possibilities may affect generation choices, namely, capital costs of renewables, the availability of energy efficiency measures, and future natural gas prices. This analysis's exploration of these three cases for both rate-based and mass-based approaches to the CPP focusing on the regional trading option.

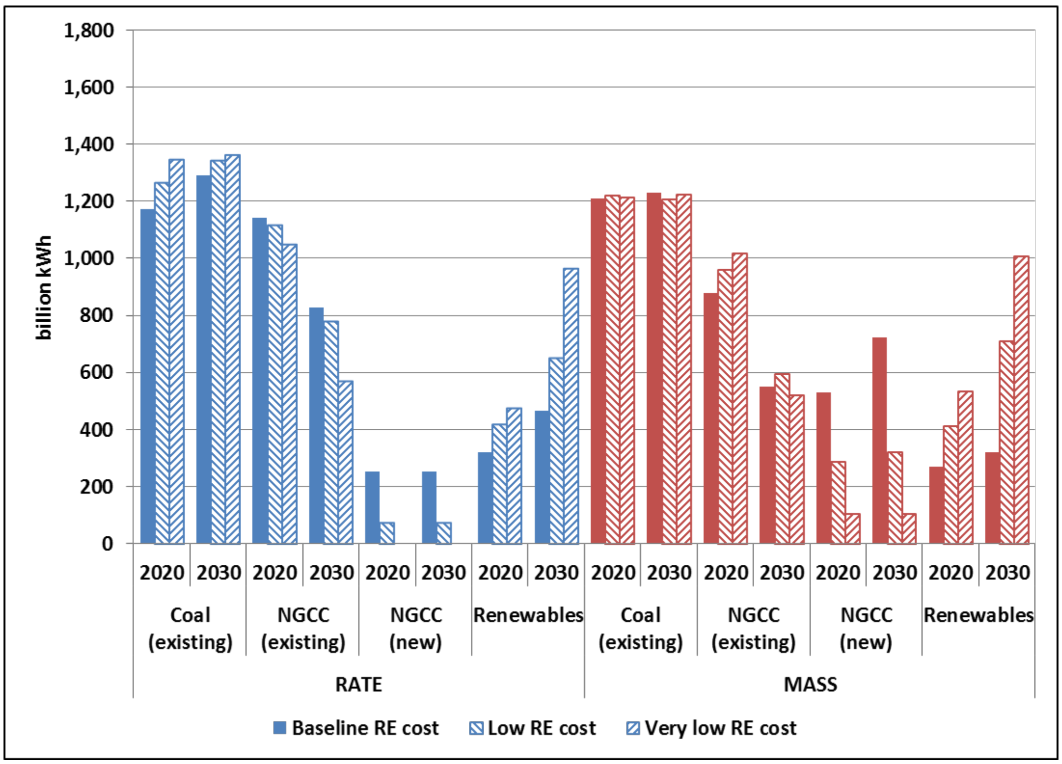
Construction of new renewables in electricity dispatch models is highly dependent on expected capital costs because these costs are the largest component of renewables' total cost. Renewables are favored under both rate-based and mass-based policies, although as discussed above there are additional incentives for renewables built into the calculation of CPP's rate-based goals. In Figure 14, the dark-shaded bars show the same generation choices in Figure 4. The lighter-shaded bars show generation for

[14] Among the factors contributing to this result are changes in electricity trade flows. The model estimates interregional electricity trade changes in response to the CPP and assumes that electricity trade occurs at the wholesale electricity price prevailing in a state during the load demand block in which the trade occurs. Like the East Central in this case, the value of this electricity trade can potentially be sufficient to offset other policy costs if regions are exporting more electricity than before, are exporting it at higher prices, or both.

two sensitivity cases: “Low RE cost,” in which it is assumed that today’s capital costs for renewables are one-third lower than the AEO assumptions (U.S. EIA 2014b) that represent baseline renewables (RE) costs, and “Very low RE cost,” in which it is assumed that today’s capital costs are one-half lower than in the AEO assumptions. For both cases, the assumption is that capital costs decline more quickly than in the model’s baseline—an assumption based on the more optimistic option in Blanford et al. (2014). These assumptions have wind costs decreasing by 1.5% per year instead of 0.9%, and solar costs decreasing by 3.1% per year instead of 2.4%.

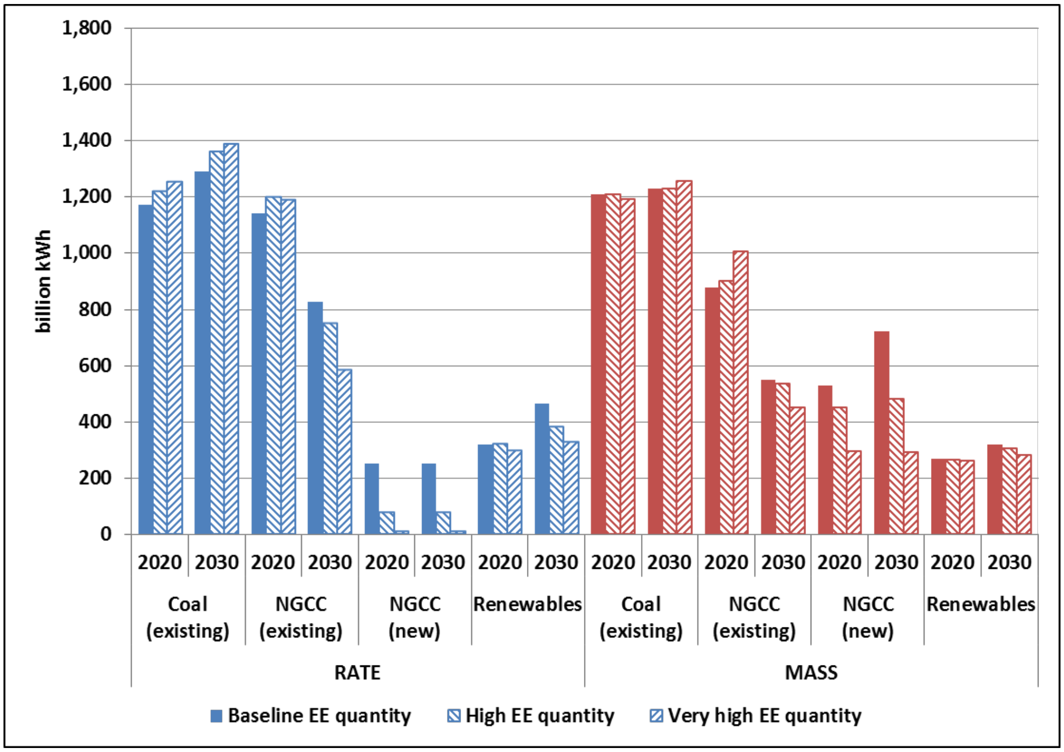
Under the rate-based approach, the “Low RE cost” and “Very low RE cost” results indicate some increase in renewable generation by 2030 if capital costs are 33% lower than in the AEO assumptions and a significant increase if costs are 50% lower. This increase has two effects: first, allowing relatively more coal units to run by offsetting their emissions in the emissions rate calculations, and second, reducing much of the need for new NGCC generation. There are also relatively more renewables under the mass-based approach, although they are mainly competing directly with new NGCC units on a cost basis and preventing the shift into new NGCC units that occurred in this case.

Figure 14. Alternative renewables costs



The next assumption of interest is the availability of energy efficiency. As a sensitivity and with no attempt to justify assumptions about a specific level, the quantity of available energy efficiency measures is presumed to be either 50% (“High”) or 100% (“Very high”) more than that given by the baseline energy efficiency numbers from the EPA (U.S. EPA 2014d), but at the same price. In the rate-based scenario, extra efficiency measures (like renewables, as depicted in Figure 14) allow existing coal units to run at a higher level. At this quantity they also offset most of the need for new NGCC units and many of the new renewables. Under a mass-based system, greater energy efficiency does not provide much assistance to coal units, but the resulting lower electricity demands mean that not many new NGCC units need to be constructed.

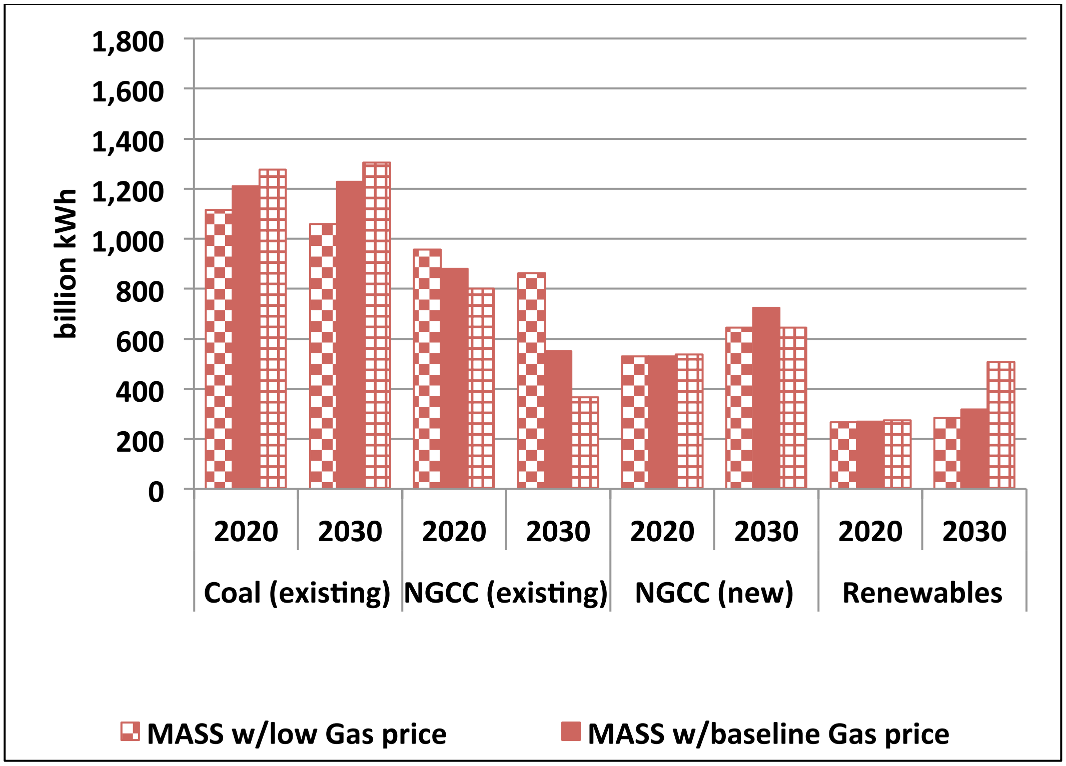
Figure 15. Alternative energy efficiency quantities



Finally, natural gas prices are an important determinant of how the whole U.S. electricity sector responds to demand levels and any existing or new policies. To explore the implications for the CPP, alternative gas prices are applied in DIEM on the basis of the high- and low-resource side cases in the AEO (U.S. EIA 2014a). These cases define gas prices that are approximately 25%-30% higher or lower than the expected baseline prices in the model.

For the mass-based scenario, Figure 16 shows that the main effects of prices changes are on coal and existing gas generation. Low prices benefit existing NGCC units that are generally less efficient (lower heat rates measured in Btus of gas per kilowatt-hour of electricity output) rather than new NGCC units. This extra gas generation reduces the need for electricity from coal. Higher gas prices generally work in the opposite direction, with the added effect of making renewables more cost competitive.

Figure 16. Alternative natural gas prices



Conclusions

The analysis provides guidance on the three key decisions faced by states as they contemplate compliance with the proposed the CPP. Each is summarized briefly below and in a bit more detail in the report's executive summary.

Rate versus Mass-based Compliance: Mass-based compliance provides more flexibility in mitigation options and introduces fewer market distortions than rate-based compliance, thereby tending to lower the overall cost of achieving a given emissions target. However, the mass-based approach tends to have a larger effect on power prices, because all generation pays for the emissions it generates. The impacts of these price effects can be mitigated in a mass-based system by deploying allowance revenues to compensate parties who are differentially affected by the price changes.

State versus Multistate Compliance: The overall cost of the compliance system is substantially lower if each state can use instruments (allowances, credits) generated in any state within its region. Under a mass-based system, the cost reduction benefits would increase further if instruments from any other state in the country could be used instead of just within the region. The cost savings of national market aggregation are not as evident under a rate-based approach.

Inclusion of New NGCC under Emissions Limits: Adding new NGCC units to the regulated universe tightens emissions constraints in a mass-based system and lowers the compliance hurdle in a rate-based system.

The analysis tests the sensitivity of the results to variations in key assumptions and parameters and finds that reducing renewable power costs and increasing the availability of energy efficiency lower compliance costs, as expected. Assumptions about the price of natural gas also affect the nature of the mitigation supply response. For instance, lower gas prices obviously favor more gas and less coal and renewables.

The analysis shows how certain key choices can affect the generation mix, cost, and prices in the power sector, generally indicating that more flexibility yields more cost-effective outcomes, and changes in the distribution of costs within the regions and states. Individual states will balance these cost and distributional considerations, subject to the political, economic, and technological conditions in each state.

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Contact
Nicholas Institute, Duke University
P.O. Box 90335
Durham, North Carolina 27708

1201 New York Avenue NW
Suite 1110
Washington, D.C. 20005

Duke Marine Lab Road
Beaufort, North Carolina 28516

919.613.8709 phone
919.613.8712 fax
nicholasinstitute@duke.edu
www.nicholasinstitute.duke.edu