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Ongoing Evolution of the Electricity Industry: Effects of Market Conditions and the Clean Power Plan on States

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SUMMARY

The electricity industry is evolving as changes in natural gas and coal prices, along with environmental regulations, shift the generation mix. Future trends in gas prices and renewables costs are likely to continue moving the industry away from coal-fired generation and into lower-emitting sources such as natural gas and renewables. The U.S. Environmental Protection Agency's Clean Power Plan (CPP) is likely to amplify these trends. The CPP rule regulates emissions from existing fossil generators and allows states to choose among an array of rate-based and mass-based goals.

This analysis uses the electricity-dispatch component of the Nicholas Institute for Environmental Policy Solutions' Dynamic Integrated Economy/Energy/Emissions Model to evaluate electricity industry trends and CPP impacts on the U.S. generation mix, emissions, and industry costs. Several coordinated CPP approaches are considered, along with a range of uncoordinated "patchwork" choices by states.

Modeling indicates future industry trends are likely to make CPP compliance relatively inexpensive, with cost increases of 0.1% to 1.0%. Some external market conditions such as high gas prices could increase these costs, whereas low gas or renewables prices could achieve many CPP goals without additional adjustments by the industry. However, policy costs can vary greatly across states, and may lead some of them to adopt a patchwork of policies that, although in their own best interests, could impose additional costs on neighboring states.

OVERVIEW

The electricity industry has been undergoing substantial change over the last decade and is likely to continue evolving in response to market trends and upcoming environmental policies. Changes in natural gas and coal prices have dramatically shifted the generation mix. Environmental regulations such as Cross-State Air Pollution Rule (CSAPR) and Mercury and Air Toxics Standards (MATS) have accelerated these adjustments. Expected future trends in gas prices and persistent declines in the costs and effectiveness of renewable generation are likely to continue moving the industry away from its traditional base of coal-fired generation and into lower-emitting sources.

The U.S. Environmental Protection Agency's (EPA's) Final Rule for the Clean Power Plan (CPP) is likely to amplify these trends (U.S. EPA 2015a). The CPP rule regulates emissions from existing fossil generators and allows states to choose from several alternative approaches: a "dual-rate" option that has subcategorized emissions rate goals for existing fossil steam units and natural gas combined cycle (NGCC) units (1,305 lb/MWh in 2030 and 771 lb/MWh by 2030, respectively), a "blended-rate" option that uses each state's 2012 historical generation to combine the separate fossil steam and existing NGCC emissions rate targets from the dual-rate approach, a "mass-based cap over (most) existing fossil units," and a "mass-based cap over existing and new fossil units" (the New Source Complement, or NSC). In addition to having the flexibility to choose among these four approaches, states can also adopt "state measures" that include plans for mass emissions limits, or they can use varied carbon dioxide (CO_2) emissions rate targets among existing units to achieve comparable reductions.

This paper explores how the industry may evolve over the next several decades in response to ongoing industry trends, including natural gas prices and renewables costs, and looks at how the Clean Power Plan may interact with, or be supplanted by, these trends. The analysis uses the Dynamic Integrated Economy/Energy/Emissions Model (DIEM), which includes a detailed electricity dispatch model of U.S. wholesale electricity markets, and it builds on work done with the DIEM model for the CPP proposal (Murray et al. 2015; Ross et al. 2015a, b). The model represents intermediate- to long-run decisions of the industry regarding generation, transmission, capacity planning, and dispatch of units. To estimate policy impacts, it minimizes electricity generation costs while meeting electricity demand and environmental policy goals.

Several potential pathways to achieve CPP emissions goals are examined: (1) the dual-rate option with separate targets for existing fossil steam and NGCC units, (2) a mass-based policy over existing units, and (3) a mass-based policy including the NSC and covering new fossil units. It is difficult to anticipate how any "state measures" or state "varied emissions rate targets" to achieve equivalent emissions reductions may look; consequently, they are not included in this analysis. The blended-rate approach appears to be the most expensive, and least likely, option and thus for brevity it is also not examined here.

Of particular interest is how states, acting in their own best interests, may choose policy options that are either comparable to, or dissimilar from, their neighbors' options. A state may be well positioned to pursue a particular policy response, for example, states with under-construction nuclear will have access to relatively cheap supplies of emission rate credits (ERCs), whereas their neighbors that are in the process of retiring coal plants may be better off with a mass approach. Given the interconnected nature of the grid, and how utilities' service territories can cross state boundaries, this analysis, after exploring broad-based trading schemes in which states adopt similar policies, examines a range of "patchwork" outcomes in which states choose responses that segment the emissions trading markets. Such disjointed tactics can have important implications for policy costs and emissions "leakage" across state lines as generation shifts to states with more favorable policy environments.

Baseline Trends in the Electricity Industry

In the absence of policies such as the Clean Power Plan that limit CO_2 emissions, the industry will still have to respond to ongoing changes in market conditions. The share of natural gas generation has increased substantially over the last decade as many coal plants have retired due to age, loss of competitive advantage relative to gas plants, or environmental regulations such as the Mercury and Air Toxics Standard (MATS).

If no new limits are placed on emissions, the model results show the following baseline trends:

- **CO_2 emissions depend critically on future natural gas prices**: Moderate gas prices that are relatively flat (i.e., approximately $4.50/MMBtu over the next 20 years) will leave the industry's emissions near today's levels. Low gas prices (i.e., below $4/MMBtu) result in significant declines in emissions from today's levels, even without new emissions limits. High gas prices would increase emissions.
- **Electricity demand growth is expected to be fairly low**: The baseline assumption in the modeling is for demand growth of approximately 0.7% per year. Higher demand growth could raise emissions by up to 20% in 2030 over more moderate demand growth.
- **Low gas prices will shift the generation mix:** Compared with moderate gas prices, low gas prices can raise gas generation by 30% and lower coal generation by 20% through 2030. Low gas prices also tend to reduce incentives for new renewable generation. High gas prices could increase coal generation by 150 terawatt-hours (TWh) and lower gas generation by 225 TWh in 2030; new renewables would make up the balance.
- **Low gas prices can initially make the Clean Power Plan nonbinding**: Emissions can be below the mass caps in the Clean Power Plan; however, this effect does not last beyond the first few years of the policy.
- **Penetration of renewable generation depends on future construction costs**: Some declines are expected in capital costs of wind units, leading to additional generation. The recent extension of the federal production tax credit (PTC) or investment tax credit (ITC) for renewables also expands wind supplies 15–40 gigawatts (GW) by the early 2020s. In the absence of a continuation of these credits, however, the wind industry will end up in the same place by 2030 as it would have without the PTC/ITC extension. For solar to become more cost competitive, the construction costs for utility-scale units would need to come closer to $1/watt than they are today.

Policy Costs of National Approaches to the Clean Power Plan

The analysis begins the investigation of the Clean Power Plan by looking at policy costs for a coordinated, national approach to the policy, before moving into an examination of the costs of less coordinated, patchwork choices by states. Policy costs encompass all costs associated with delivering electricity to meet grid demands. At a national level, these costs include mainly fuel expenditures, plant operating costs, and spending on new construction.

With respect to national approaches to the Clean Power Plan, the modeling broadly finds the following:

- **CPP policy costs are quite low for the United States:** Regardless of the policy options chosen by states, costs are quite low (i.e., cost increases in the 0.1%–1.0% range) across most assumptions about future trends in the industry.
- **The mass-based approach with the New Source Complement has policy costs roughly equivalent to those of the dual-rate approach:** For the standard set of assumptions used in the DIEM analysis, mass with NSC raises overall generation costs for the United States by approximately 0.5% in present value terms over the next few decades, whereas the dual-rate approach increases costs by 0.7%. The two options also provide similar emissions reductions

through 2030, although these reductions are dependent on the specific set of standard assumptions about future market trends. After 2030, a dual-rate approach leads to additional emissions as electricity demand grows, and the addition of renewables creates more ERCs, thus allowing coal plants to run more.

- **Mass cap over existing units has the lowest policy costs:** At an overall cost of approximately 0.1%, this policy option has lower costs than the mass cap with NSC or the dual-rate approach. However, its costs are low because it achieves significantly fewer emissions reductions than the other approaches over its first decade.
- **Mass-based options are less sensitive to future market conditions:** Mass-based options have a narrower (and lower) range of costs across an array of possible futures than rate-based options, thereby increasing certainty for the industry.
- **Prices for mass allowances and ERCs are quite low:** For a policy applying to existing units, mass allowances would cost approximately $7/ton in 2030, although this price is sensitive to market conditions and is even lower before 2030. A mass cap with NSC would have a higher allowance price at $15/ton in 2030. ERC prices for a national, dual-rate option would be approximately $15/MWh by 2030.
- **High natural gas prices have the greatest potential to raise policy costs:** Increased gas prices could raise the costs of the mass-based approaches to approximately 3.0% to 3.5%, compared with 0.1%–0.5% should gas prices remain stable at relatively moderate levels. The dependency of costs on gas prices indicates that gas is a fairly important option for responding to the CPP policy.
- **Low natural gas prices could reduce policy costs to almost zero:** For the less comprehensive approach of a mass cap over existing units, there would be essentially no policy costs, whereas a mass cap with NSC would have costs of approximately 0.1%. The dual-rate option benefits less from low gas prices and has policy costs of approximately 0.4% compared with 0.7% for moderate gas prices.
- **Energy efficiency (EE) measures are an important mechanism for containing costs:** The analysis' standard assumption (based on U.S. EPA 2015b) is that energy efficiency (EE) measures can lower incremental baseline demands by 1% per year, but lower EE reductions of 0.5% per year would double the (small) costs of the mass with NSC and dual-rate approaches. Conversely, if EE measures reduce incremental demand by 1.5% per year, CPP costs would be close to zero.

State-Level Policy Costs and Patchwork Approaches to the Clean Power Plan

In the context of estimating national-level policy costs, interstate trade in ERCs or mass allowances, which are merely transfers among agents in the economy, nets out across the country as a whole. However, when considering subnational cost estimates, purchases and sales of such compliance instruments must be included in a state's policy costs. At the state or regional level, policy costs also include additional factors such as estimated costs or benefits of any net electricity flows into or out of an area. Caution should be used when interpreting state-level cost estimates, especially when the states are part of an integrated, multi-state electricity market. In the context of non-coordinated, patchwork policy approaches in which states choose policies different from those of their neighbors, they can be designed to achieve local benefits, but they may increase inefficiency overall and lead to distorted markets.

Among the general cost findings at the state level are the following:

- **Policy costs can vary significantly across states:** Some states—or regions—are clearly better off with one approach instead of another—for example, West Virginia's costs are much lower under mass than rate. For other states, the answers are less clear and can vary with future market conditions.

- **The actions of neighboring states have large impacts on a state's costs:** Neighboring states' choices can be as important as the choices a state makes for itself. Interlinked electricity markets allow for generation shifting across state borders, leading to changes in the distribution of policy impacts. As a general rule, choices that lead to high compliance costs in neighboring states can lower costs within a state as that state becomes a comparatively low-cost provider of electricity.
- **The outcomes of patchwork approaches depend on the size of ERC/allowance markets:** States with expensive within-state options for reducing emissions will benefit from broad trading markets for ERCs and allowances. States in a position to sell ERCs and allowances will have to evaluate the breadth of the markets—if, for example, only states capable of producing cheap ERCs choose a rate-based CPP policy, the market price of ERCs may be quite low (e.g., \$0–\$5/MWh), providing few benefits and no incentivizes for additional renewables. Similar effects can be seen with mass allowances. However, low ERC prices (or allowance prices) may encourage additional states to enter into trading groups to take advantage of those prices.

Generation and "Leakage" of Emissions to New Sources

To achieve its goal of reducing emissions, the Clean Power Plan will need to make adjustments to the generation mix of the industry. How these adjustments will occur depend on both market conditions and the policy choices made by states. One concern is that some forms of the CPP policy may lead to emissions "leakage" from the existing sources covered by the policy to fossil sources that are outside of the policy, largely new NGCC units. The CPP policy option of a mass cap over existing units contains two types of leakage provisions designed to alleviate this concern: first, using output-based allocations to encourage generation from existing NGCC units instead of new units and, second, using allowance set-asides for renewable generation. Leakage can be determined by comparing emissions from this mass cap over existing units—or the emissions rate approach—to emissions from the mass cap with NSC, which covers (most) existing and new CO_2 sources. In general, the modeling suggests that CPP leakage provisions do not appear sufficient to prevent leakage—an important factor when evaluating policy options.

With respect to generation and emissions, the modeling finds the following:

- **Starting the Clean Power Plan in 2022 prevents the need for sizable, quick adjustments in generation:** Along with low gas prices, the federal extension to renewables PTC/ITC, and the redefinition of policy targets in the CPP Final Rule, the change in the CPP start year from 2020, as originally proposed, to 2022, as specified in the Final Rule, will prevent large adjustments by existing fossil plants in the near term.
- **The mix of coal and gas generation in 2030 depends on states' policy choices:** Coal generation would decrease by 17% from baseline trends if most states choose a mass cap over existing units, and by 27% to 29% under the mass cap with NSC or dual-rate approach. Under a mass cap over existing units, gas generation declines only slightly because coal generation remains relatively high, but gas can increase to a small degree under the other two policy options (on the order of a 1% to 4% increase). None of the range of tested assumptions about policy choices or future market conditions leads to a "dash to gas."
- **Penetration of renewables depends on several factors:** Compared with a mass cap over existing units (using the standard set of assumptions about market trends in the model), a rate-based approach can help incentivize renewables, which can produce ERCs for use by fossil plants, leading to an extra 75 TWh of generation by 2030. Another important determinant of renewable penetration is their capital costs; using low capital-cost estimates from NREL (2015) can lead to an additional 120 TWh of generation in 2030. However, the largest determinant in renewable generation is high gas prices in conjunction with the CPP policy, which can lead to an extra 200 TWH to 300 TWh in 2030, depending on states' policy choices.

- **Leakage of emissions through generation shifts can be important:** With the standard modeling assumptions, a mass cap over existing units can lead to emissions that are 7% higher in 2030 than emissions under the mass cap with NSC as generation shifts from covered to uncovered fossil sources. Higher-than-expected growth in electricity demand could double or triple this leakage.
- **Leakage under a dual-rate policy can also be significant:** DIEM's standard assumptions lead to the finding that the dual-rate and mass cap with NSC approaches have similar emissions through 2030, but this finding is highly dependent on those assumptions.[1] High electricity demands or high gas prices can result in emissions 10% to 15% higher under the dual-rate option than under the NSC. However, lower-than-expected gas prices or electricity demands result in emissions that are 5% to 8% below the NSC.
- **Patchwork state choices can lead to additional generation shifting and emissions leakage:** Patchwork policies that lead to low ERC prices in a limited number of rate-based states (as would occur if only those states with under-construction nuclear units or access to cheap wind resources chose a rate-based approach) can also shift fossil generation into these rate-based states and increase leakage by 40–50 $MMTCO_2$ over the national NSC cap of 1,550 $MMTCO_2$. The more states that choose to go with a rate policy, the more this effect is reduced.

The remainder of this paper describes historical trends in the electricity industry and expected trends in the absence of the Clean Power Plan, details the DIEM model structure and assumptions, defines the investigated policy scenarios, examines the model findings for the coordinated national approaches to the CPP policy, and explores patchwork scenarios.

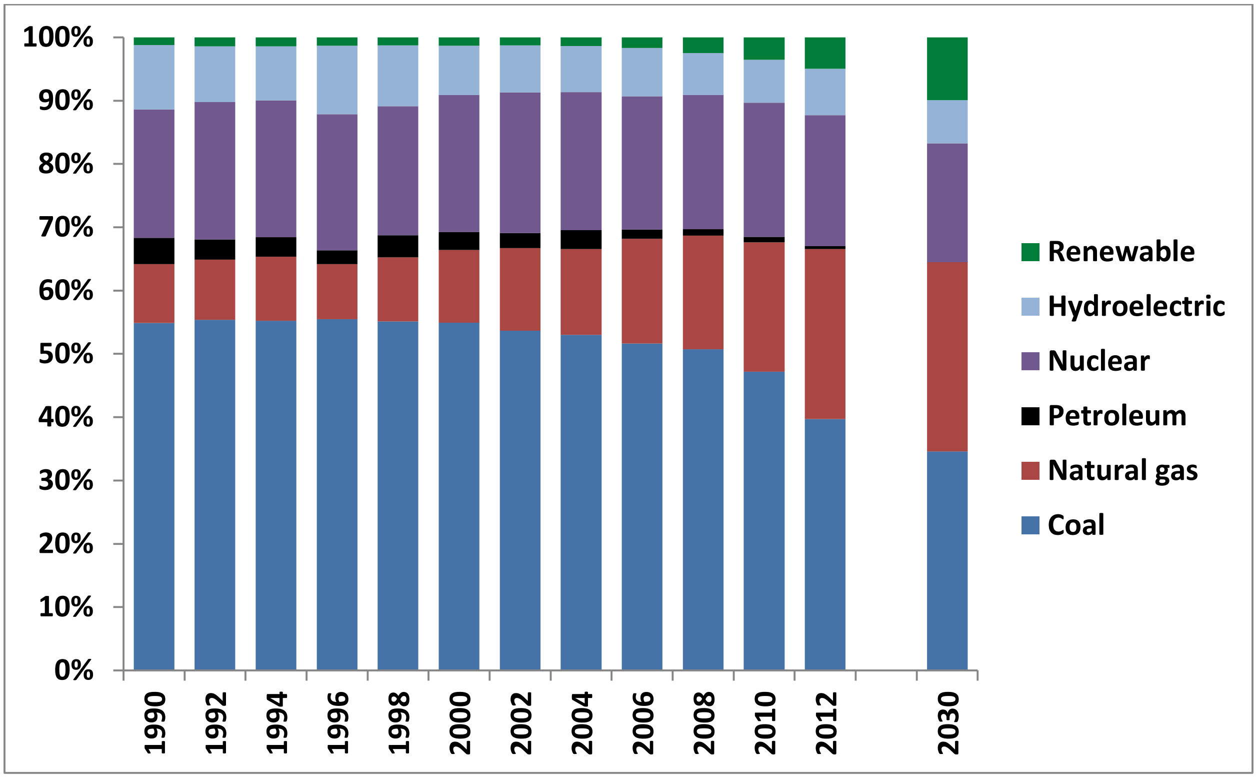
BACKGROUND

Over the first part of this millennium, the electricity industry has undergone a significant revolution in the ways it generates electricity (see Figure 1)—the result of falling natural gas prices and, to a lesser extent, declines in the costs of constructing wind and solar units. From 1990 through 2000, the share of electricity produced by coal was steady at approximately 55%, while that of natural gas hovered at 10% and nuclear at 22%. During this decade, renewables (excluding hydroelectric) provided less than 1.5% of the electricity consumed in the United States. Between 2002 and 2012, however, coal dropped from its initial 55% share to less than a 40% share. Most of this difference was made up by an increase in natural gas from 10% to 27%. Non-hydro renewables also gained, accounting for 5% of total generation.

These trends are expected to persist as electric utilities continue to respond to environmental policies such as CSAPR and MATS as well as to other cost factors. Natural gas prices are expected to remain relatively low on a historical basis as the shale gas revolution persists. Costs for new renewables are also forecast to keep on declining. In the absence of new policies such as the Clean Power Plan, the DIEM model estimates that by 2030, coal generation will represent only one-third of all electricity. Natural gas, through increased utilization of existing units and construction of new NGCC units, comes close to reaching an equivalent share with coal. Renewables also double from 2012 levels as state renewable portfolio standards increase in stringency and utilities choose to install wind and solar on a strictly cost basis.

[1] Unlike emissions under other approaches, emissions from a dual-rate approach climb fairly significantly after 2030.

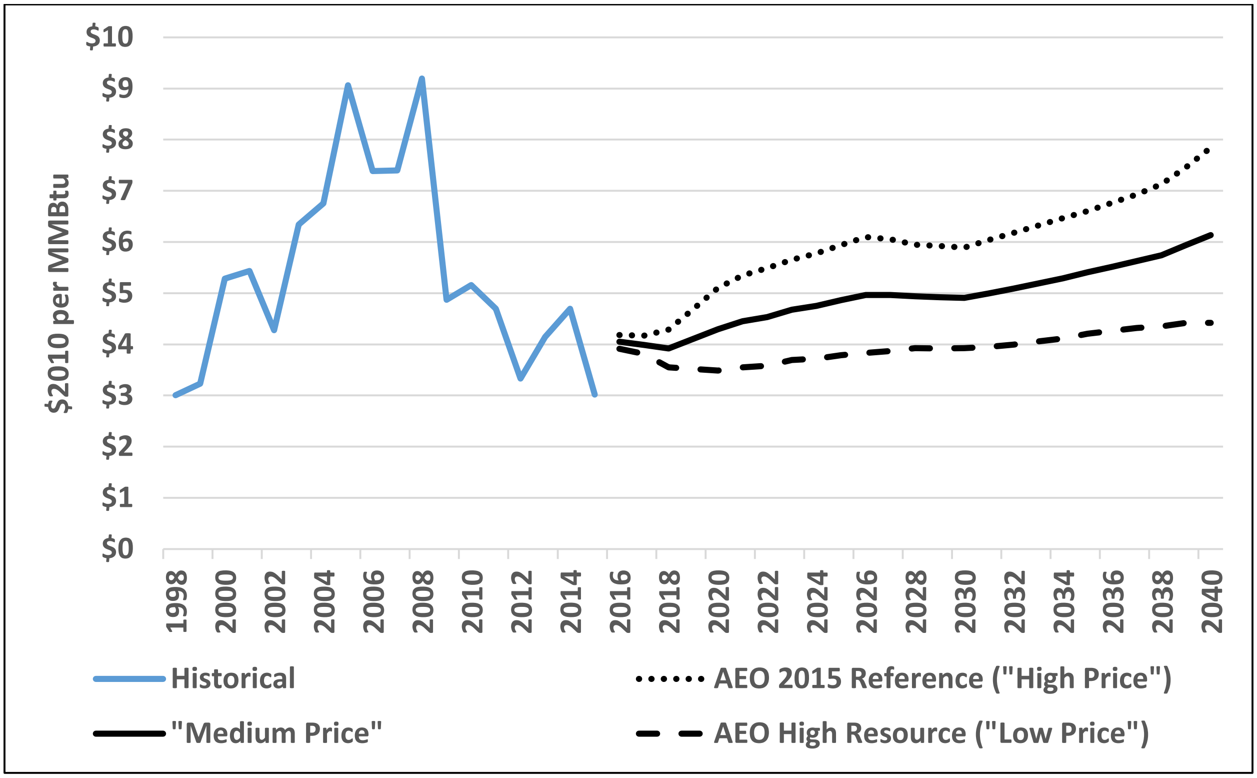
Figure 1. U.S. historical and forecast generation shares



Source: Authors' calculations based on U.S. Energy Information Administration (EIA) state historical data (U.S. EIA 2015d) and a baseline forecast from the DIEM model for the year 2030.
Note: Generation is by electric utilities and independent power producers.

Beyond the baseline forecast shown in Figure 1, the Clean Power Plan has the potential to accelerate existing gas and renewables trends, though how quickly and extensively remains an open question. To address the importance of natural gas prices, this analysis looks at a range of possible future prices (see Figure 2). Compared with previous decades, the next two decades are expected to see relatively low gas prices. The Annual Energy Outlook (AEO) 2015 Reference Case (U.S.EIA 2015a) is used to define the "high price" forecast because that case most closely aligned with expectations as they were evolving during 2014. Since then, gas prices have continued to decline, so most of the modeling in this analysis focuses on a "medium price" forecast that is halfway between the Reference Case and AEO's High Resource Case, which assumes continued expansion of gas resources and which leads to low, stable prices.

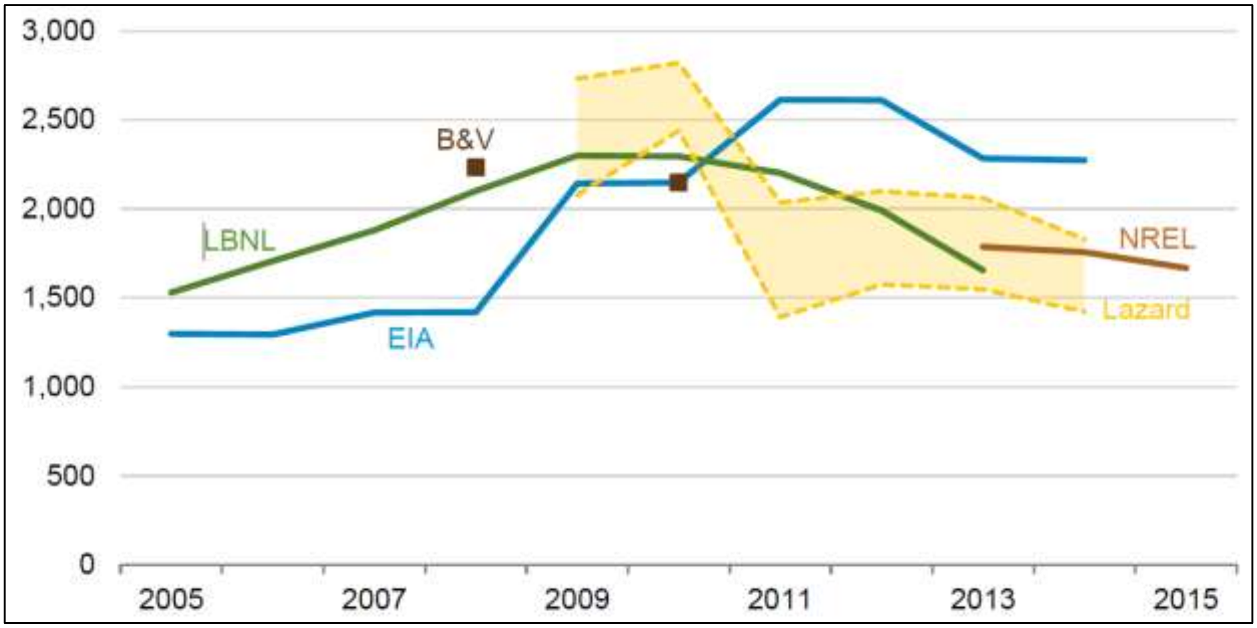
Figure 2. U.S. average historical and forecast natural gas prices for electricity generators



Source: U.S. EIA (2015d) and authors' calculations based on U.S. EIA (2015a).

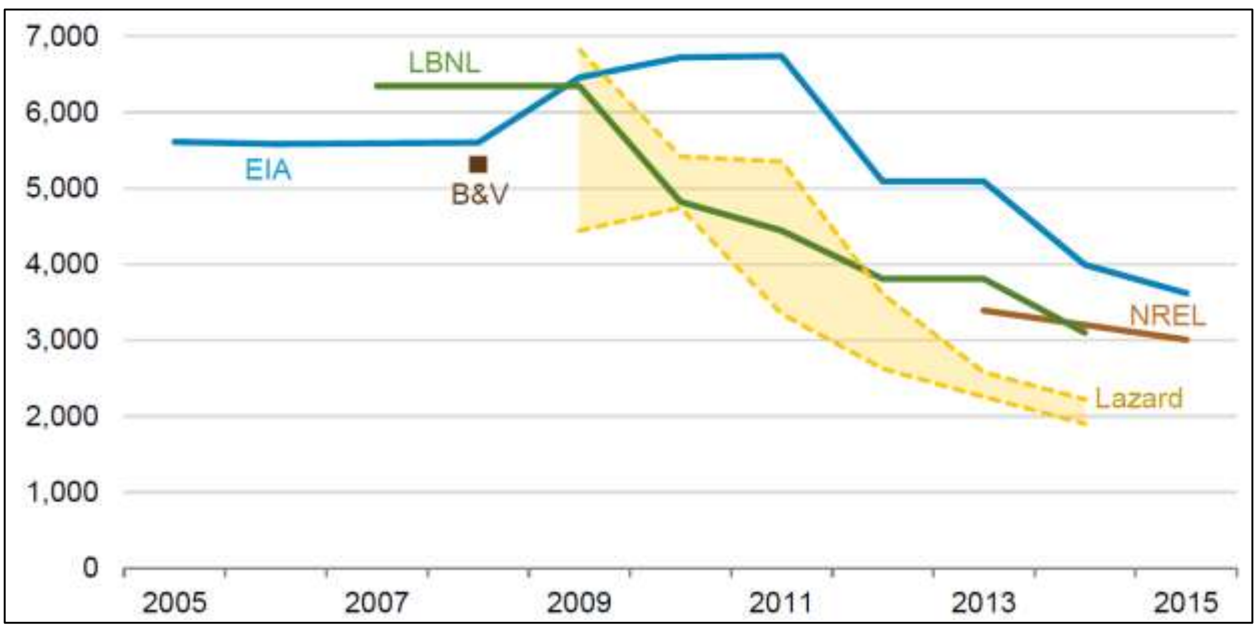
The last decade has also seen a rapid evolution in renewables markets. Wind costs have been comparatively steady, depending on the data source (see Figure 3), and the effectiveness of wind units has improved as turbine heights have increased to take advantage of stronger winds aloft. Capital costs for utility-scale solar photovoltaic (PV) units have decreased swiftly, even as efficiencies have improved (Figure 4). Another notable feature of these data series is the dispersion of the cost estimates, even the historical estimates. This analysis looks at several estimates of renewables costs.

Figure 3. Estimated capital costs for wind generation, 2005–2015 ($2014/kW)



Source: U.S. EIA (2016), Figure A-4.

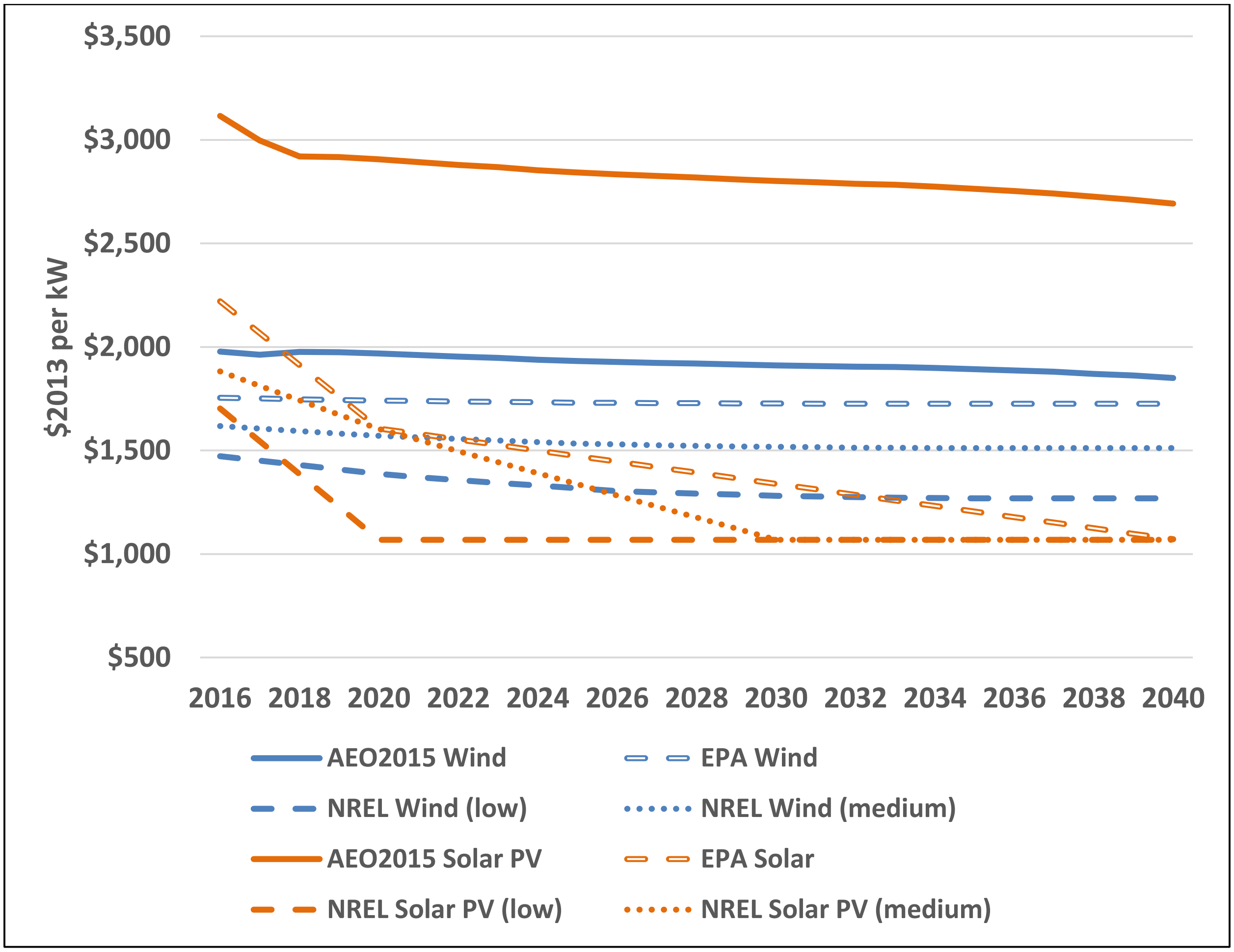
Figure 4. Estimated capital costs for utility-scale solar photovoltaic generation, 2005–2015 ($2014/kW)



Source: U.S. EIA (2016), Figure A-12.

Figure 5 presents the range of cost forecasts for new wind and solar PV generation considered in this analysis. The AEO 2015 provides a comparatively conservative estimate of future cost improvements, shown as solid lines. The standard assumption adopted in this paper comes from the EPA analysis of the Clean Power Plan in the Final Rule Regulatory Impact Analysis, or RIA (U.S. EPA 2015a). The hollow-dashed lines represent a midrange forecast wherein wind costs are relatively stable, but solar PV costs eventually decline to $1/watt (a price at which they can compete with fossil sources on a cost basis, even with low gas prices and in the absence of subsidies). The assumptions of the National Renewable Energy Laboratory (NREL) medium case forecast (NREL 2015) are similar to the EPA assumptions; however, the NREL low case forecast provides a useful sensitivity analysis because it projects solar PV reaching $1/watt in the near future. As these forecasts evolve, the renewable industry will continue to play an increasing role in utility-scale electricity generation.

Figure 5. Projected overnight capital costs for wind and solar photovoltaic generation, 2016–2040 ($2013/kW)



Sources: U.S. EIA (2015a), U.S. EPA (2015b), and NREL (2015).

METHODS AND ASSUMPTIONS

Policy scenarios are analyzed using an updated version of the Dynamic Integrated Economy/Energy/Emissions Model (DIEM), developed at Duke University's Nicholas Institute for Environmental Policy Solutions.[2] DIEM includes a macroeconomic or computable general equilibrium component (DIEM-CGE) 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

[2] See Ross 2014a,b for documentation of the previous version of DIEM.

energy efficiency considerations, which is standard treatment for U.S. EPA policy analysis (U.S. EPA 2015b).[3] 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, 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 are based on data from the National Electric Energy Data System (NEEDS) database v.5.15 (U.S. EPA 2015c), are aggregated into model plants on the basis of their location, characteristics, and equipment configurations to reduce the dimensionality of the mathematical programming problem.[4] Some new plant options, largely for fossil and nuclear generation, are included using costs and operating characteristics from AEO 2015 (U.S. EIA 2015a). In addition, AEO forecasts provide annual demand and fuel price forecasts. Data on capital costs, availability, and effectiveness of new hydroelectric, wind, and solar units are taken from several sources, as discussed below.

Plants in the model are dispatched on a cost basis to meet demand within each region through 2060. 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, 2015c), AEO regional forecasts, and state-level demand data from the State Energy Data System, or SEDS (U.S. EIA 2015b). 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's CO_2 emissions targets, 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). First, coal plants can improve their efficiency (their heat rates measured in terms of Btus of fuel burned per kilowatt hour of electricity generated).[5] Second, generation from higher-emitting sources such as existing coal plants can be redispatched to lower-emitting sources such as existing NGCC plants that may not be running at full capacity, assuming this policy response is cost-effective. Third, new low- or zero-emitting sources can be constructed to reduce CO_2 emissions. 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 Clean Power Plan.

DIEM can select these 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 industry. First-year costs and lifetimes of the measures are based on EPA data, which assume an initial cost of $1,100/MWh and which decrease to $660/MWh by 2025 (U.S. EPA 2015b). The quantity of efficiency measures available is, in most years, sufficient to reduce electricity demand by 1.0% of the previous year's demand, before consideration of annual demand growth that also occurs in the current year. Following the EPA analysis, it is also assumed that energy efficiency measures decay over 20 years and that utilities and program

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[3] Although electricity demands are fixed when DIEM-Electricity is run by itself, there are flexible supply curves for coal, natural gas, and biomass within its electricity component. The fossil fuel supply responses are based on elasticities implied by the AEO resources side cases, and the biomass supply curves come from the EPA (U.S. EPA 2013).

[4] Data from U.S. EIA (2015d) are added to account for recent construction and retirement decisions.

[5] Data from the EPA's CPP RIA (U.S. EPA 2015b) are used to define regional possibilities for efficiency improvements. Coal units 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 as measures that count toward CPP policy goals.

participants split the costs of the measures equally. As a general rule, at the prices in the EPA analysis, the model usually finds that it is cost-effective to adopt the efficiency measures in both the baseline and policy scenarios, the implications of which are discussed below.

Among the more important assumptions in the model are those regarding natural gas prices and construction costs for renewable generation. As a consequence, results from DIEM are presented for a set of "standard assumptions" and a range of alternatives to better reflect both changes in today's markets and future uncertainties. For natural gas, the starting point for developing forecasts is the AEO 2015 Reference Case (U.S. EIA 2015a). The AEO also provides a side case that has significantly lower gas prices (the AEO High Resource Case). Given changes in gas markets since the AEO 2015 was released, the reference case no longer appears consistent with today's expectations. Thus, the "standard assumption" on natural gas prices in the DIEM modeling, unless otherwise identified as a sensitivity case, is that gas prices are half way between the Reference Case and the High Resource Case, as shown in red in Table 1.

Table 1. U.S. delivered natural gas price forecasts ($/MMBtu)

	2020	2025	2030	2035	2040	2016–2037 average
High gas price (AEO 2015 Reference Case)	$5.07	$5.79	$5.67	$6.57	$7.82	$5.38
Medium gas price (standard assumption)	$4.34	$4.78	$4.70	$5.36	$6.14	$4.57
Low gas price (AEO High Resource Case)	$3.60	$3.76	$3.74	$4.14	$4.46	$3.76

Source: U.S. EIA (2015a) and authors' calculations.

Capital costs for renewable generation are also significant determinants of CPP policy impacts and can vary substantially from one data source to another, as shown in figures 3 and 4 above. Costs for wind and especially solar photovoltaics (PV) have been declining rapidly; however, future trends are unclear. Costs for these two types of generation have decreased more than was expected when the AEO 2015 Reference Case was developed. Thus, the standard assumption in DIEM is based on the EPA's data from the CPP Final Rule RIA (U.S. EPA 2015b), as shown in Table 2 in red. To test the sensitivity of model results to this assumption, forecasts from the NREL Annual Technology Database for NREL's low case (NREL 2015) are also used in some model runs as a "low cost" case. The original data from AEO 2015 would be considered a "high cost" case, although these results are not presented in this paper.

Table 2. Overnight capital costs for utility-scale wind and solar photovoltaic generation ($/kW)

	2020	2025	2030	2035	2040
Wind					
EPA (standard assumption)	$1,682	$1,672	$1,668	$1,668	$1,667
NREL ATB – Low	$1,570	$1,550	$1,540	$1,536	$1,536
Solar Photovoltaic					
EPA (standard assumption)	$1,552	$1,423	$1,294	$1,165	$1,035
NREL ATB – Low	$1,069	$1,069	$1,069	$1,069	$1,069

Source: U.S. EPA (2015a) and NREL (2015).

Other important assumptions include electricity demand growth and the availability of EE measures that simultaneously reduce demand and provide ERCs for states adopting a rate-based approach to the Clean Power Plan. For electricity demand growth, the "standard assumption" in DIEM is to use growth rates from the AEO 2015 Reference Case (U.S. EIA 2015a), which has demand growth of some 0.7% per year on average for the United States (select U.S. regions grow at faster or slower rates). As alternatives, a "medium-high growth" case is defined as an additional 0.5% per year growth in demand in each region and a "high growth" case as a full 1.0% per year additional growth. Alternatively, a "low growth" case is defined as a demand growth rate that is 0.25% per year less than expected in the AEO forecasts.

EE measures can have market effects similar to those of changes in the growth rate of electricity demand and can have the added policy benefit of generating ERCs for compliance with rate-based CPP approaches. Although the electricity demand forecasts from EIA already include some efficiency improvements, additional improvements may be achievable. It is difficult to estimate the costs of such measures because most research shows the measures to be relatively cost-effective. Thus the standard assumption across all cases is to use the above-described prices from the EPA analysis (U.S. EPA 2015b). In *most* cases, the EE measures are cost-effective at these prices, making the quantity of available energy efficiency the most interesting sensitivity. The standard assumption in the DIEM model runs is a "medium EE" case based on the EPA analysis, which assumes that energy efficiency can reduce demand as much as 1.0% per year from the previous year's baseline electricity demand. To evaluate the importance of EE measures, DIEM defines a "low EE" case, in which this rate is reduced to 0.5% per year and a "high EE" case, in which the rate is 1.5% per year.

To summarize—and unless otherwise specified—the "standard assumptions" include the following:

- "Medium" gas prices of $4.57/MMBtu on average over the next 20 years
- "Medium" renewables capital costs based on EPA data on wind and solar PV generation
- "Medium" EE improvements based on EPA data of 1.0% per year over the baseline
- "Medium" electricity demand growth based on the AEO 2015 Reference Case of 0.7% per year.

In graphs such as those related to generation, baseline findings do not include EE measures. These measures primarily appear in the baseline is when policy costs are estimated, as discussed below.

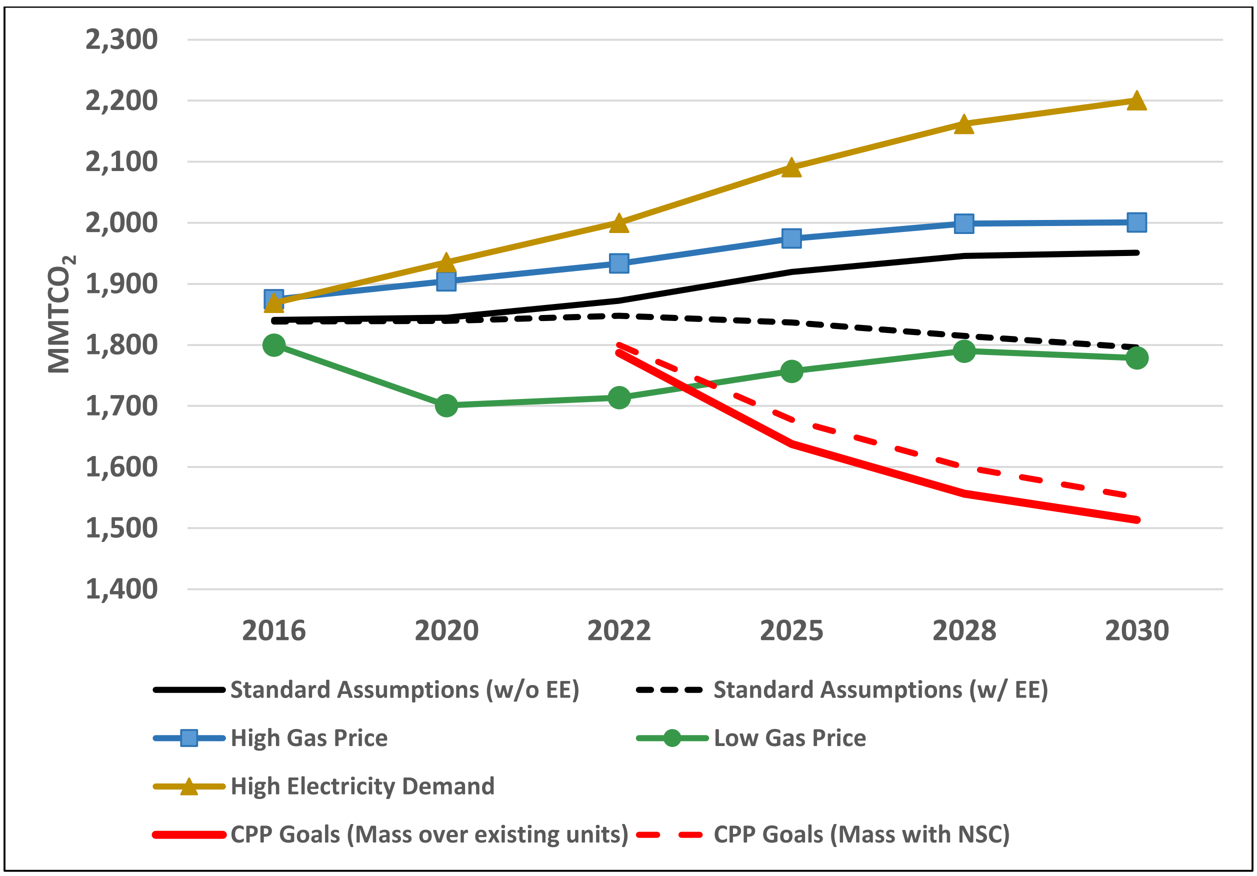
DIEM reflects recent extensions of the federal tax credits for specific types of renewable generation and the assumption that, in the long term, nuclear plants can receive a second 20-year life extension instead of retiring at 60 years.

BASELINE TRENDS

As would be expected, the evolution of the electricity industry will be quite sensitive to future market conditions. How the future plays out will determine the ease with which the sector can meet electricity demands, while achieving any environmental policy goals. Figure 6 illustrates the breadth of possible emissions trends that can occur in the absence of any new policies in the industry. Using the standard assumptions in DIEM, baseline emissions increase slightly over the next 15 years, assuming expectations for electricity demands and efficiency improvements follow estimates in the AEO 2015 Reference Case. Additional energy efficiency of 1.0% per year would reduce demand by some 8% in 2030 and result in slightly declining CO_2 emissions. Low, and stable, natural gas prices have the most dramatic impact on emissions, followed by the possibility of significantly higher electricity demand growth.

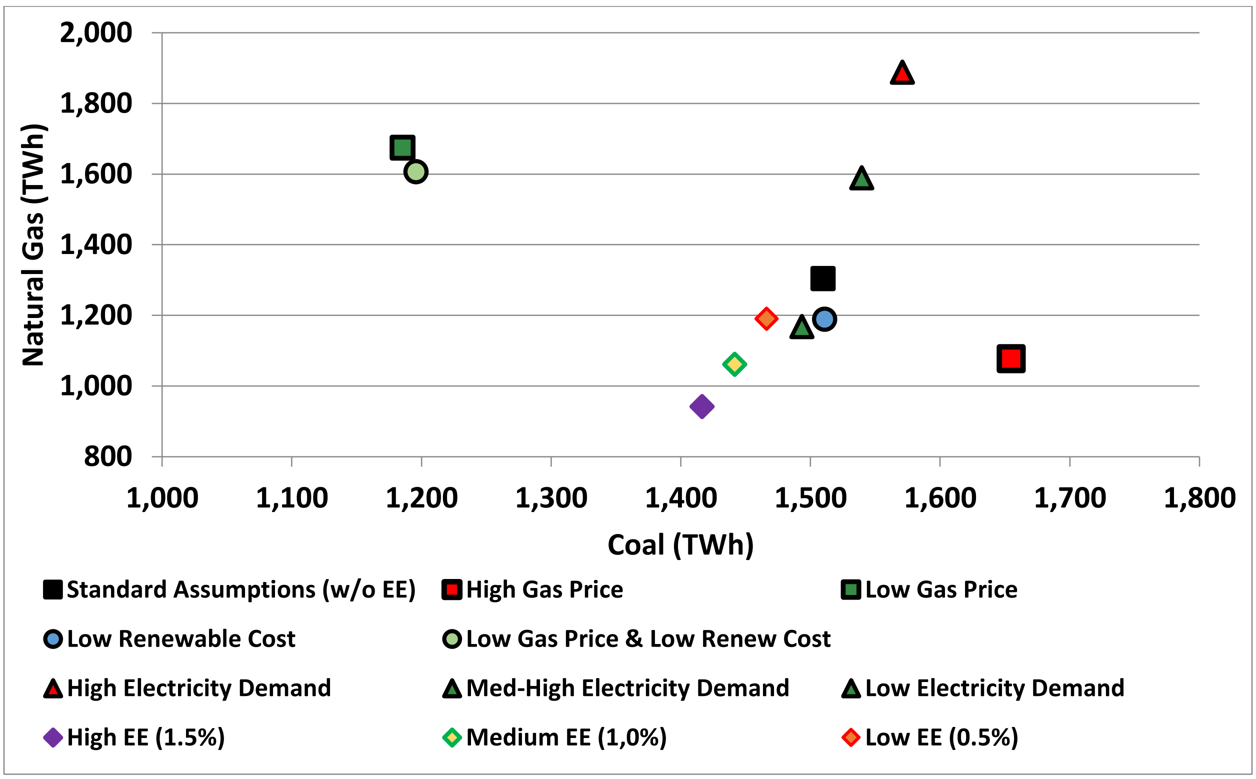
The figure contrasts these trends to the mass goals laid out in the Clean Power Plan. The trends highlight that in the absence of the Clean Power Plan none of the tested market conditions lead to baseline emissions that decline substantially as the result of current policies. However, in the near term for the United States as a whole, the Clean Power Plan may be non-binding if gas prices remain near today's levels.

Figure 6. U.S. baseline CO_2 emissions under alternative assumptions



Emissions trends are largely driven by the country's mix of coal and natural gas generation (petroleum contributes an insignificant amount). Figure 7 presents DIEM forecasts of this generation mix for 2030. Because nuclear generation is not retiring for economic reasons in the model and hydroelectricity is also steady across the sensitivities shown in the graph, any overall changes in total coal-gas generation come from changes in renewable generation (largely wind and solar PV generation, with small amounts of landfill gas and geothermal generation).[6] The first comparison tests the range of coal-gas generation across changes in natural gas prices. The standard set of DIEM assumptions with medium gas prices has roughly comparable amounts of generation from the two sources (1,500 TWh from coal and 1,300 TWh from gas). With low gas prices, coal falls below 1,200 TWh and gas climbs to almost 1,700 TWh. Less dramatic adjustments occur if gas prices are higher through 2030 and beyond. Low capital costs for renewables have little effect on coal generation; the increased renewable generation is offset by a small decline in gas generation. Increased growth in electricity demand, either to 1.2% per year or 1.7% per year, is largely met through additional gas generation. Adoption of EE measures beyond those already embedded in the AEO forecasts leads to roughly equal declines in coal and gas generation, compared to a baseline without additional energy efficiency.

Figure 7. U.S. baseline fossil generation in 2030 under alternative assumptions about future trends



POLICY SCENARIOS

Starting from these industry conditions, the CPP policy scenarios incorporate the emissions goals defined in U.S. EPA (2015a) that are, in part, used in the EPA's illustrative analysis in the CPP Final Rule RIA (U.S. EPA 2015b). These options define interim goals that must be met on average in the model over the periods 2022–2024, 2025–2027, and 2028–2029. Banking of ERCs and mass allowances is allowed in the

[6] DIEM includes EPA data on the availability of new hydroelectric generation (U.S. EPA 2015b), all of which is installed for economic reasons in the model's baseline forecasts.

model across the policy's 2022–2029 interim period. For 2030 and later years, the final goal described in the EPA's calculations must be met in each subsequent five-year time period in the DIEM model. The analysis examines these emissions goals using several of the mass-based and rate-based approaches defined in the Final Rule (U.S. EPA 2015a).

These goals are used to define three main classes of policy scenarios:[7]

- "Mass (exist)"—Mass-based trading occurs among existing fossil fuel-fired units whereby the states' mass goals calculated by the EPA (U.S. EPA 2015a) are applied to the universe of affected fossil sources. This universe essentially includes all fossil units (other than peaking units) above 25 megawatts in capacity.
- "Mass (all)"—Mass-based trading occurs with the New Source Complement, using the EPA-calculated state mass goals with an adjustment for new NGCC units. The calculation of these goals assumes that future electricity demand growth is met in states through construction of new NGCC units.
- "Rate (dual)"—Affected units meet subcategorized fossil steam or natural gas emissions rate targets. Fossil steam units in each state are required to meet interim emissions rates of 1,671, 1,500, and 1,380 lb/MWh in the periods 2022–2024, 2025–2027, and 2028–2029, respectively. In 2030 and thereafter, the fossil steam units must meet a 1,305 lb/MWh rate. Existing NGCC units meet their own subcategorized rate goals of 877, 817, 784, and 771 lb/MWh in the same periods. DIEM meets subcategory-specific rates for all units within each subcategory in each region, including ERCs from within a state or purchased from other states.[8]

ERCs are generated in several ways: from fossil steam or NGCC units operating below emissions rate goals, from existing NGCC units creating "gas-shift" ERCs for use solely by coal units, from new or under-construction nuclear plants in several states (along with nuclear uprates), and from allowable types of renewable generation built after 2012 (this generation includes hydroelectric, geothermal, wind, and solar generation). Demand-side energy efficiency is also eligible to generate ERCs. It is assumed that states pursuing a mass-based approach do not sell ERCs into rate-based states.

Because ERCs are created by plant generation decisions, there is no need for states to decide on ERC allocation schemes under rate-based CPP policies. For most mass-based approaches, the allocation of allowances to units by states does not affect the dispatch decisions of generators providing electricity in wholesale markets.[9] However, the CPP mass-based option covering only existing units includes "leakage" provisions designed to encourage operation of existing NGCC units, rather than construction of new NGCC units that are outside of this option's emissions cap. These provisions are modeled through the output-based allocations specified in the rule, whereby states allocate allowances to existing NGCC units in proportion to their generation (up to the quantity specified for each state in the Clean Power Plan).[10] Similarly, in a mass-based approach covering existing units, renewable generation constructed after 2012 is allocated 5% of the policy's allowances to encourage new renewables. This provision is modeled as a production tax credit, wherein the value of the credit is a function of the value of the allowances and the amount of qualifying renewable generation.

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[7] Results for scenarios with state-specific blended coal/gas emissions rate goals have been dropped for clarity. These scenarios are the most restrictive in terms of states' options and thus the most expensive.

[8] In both rate- and mass-based compliance, each individual unit must submit any necessary ERCs or allowances required for that unit's compliance. DIEM is modeling rate- and mass-based compliance assuming some form of regional trading, which means that all units in a region meet the region's overall mass limit or emissions rate goal on average, including any ERCs used to meet the rate goal.

[9] Allowance allocation affects both utility profits and determination of retail electricity prices.

[10] In the proposed model rule, only NGCC generation above a 50% capacity factor during each interim compliance period and the final compliance period can earn allowances.

Examination of the CPP policy scenarios begins with an investigation of coordinated, national approaches to meeting the emissions goals for the three approaches under consideration: a mass cap over existing units, a mass cap including the NSC, and a dual-rate approach. In these cases, the emissions rate or mass goals can be met through trading of ERCs or allowances across the nation, allowing states to take advantage of any cost savings that can be achieved through trading obligations with states that possess lower-cost methods of meeting the emissions goals. It is assumed in all of these "national" approaches that California and the RGGI states pursue a mass cap with NSC approach regardless of the choices by other states. RGGI states trade among themselves and are willing to enter into trading with any other states adopting the NSC, but it is assumed that California always uses its AB 32 policy as the method of meeting the CPP goals laid out in its NSC and does not trade allowances with any other states.

For simplicity, some types of results for these national approaches are presented using the aggregated regions shown in Figure 8. Other results are shown for individual states in other figures and tables.

Figure 8. Regional groupings of states for reporting

Findings of the DIEM model for the national policy options are used to specify a range of patchwork CPP approaches whereby states pursue different policies to meet their emissions goals. Some states may choose a rate-based approach due to their capacity to generate, and perhaps sell, ERCs. Other states may have a difficult time meeting emissions rate goals and thus may lean toward the mass-based options. Because the actions of neighboring states—and any more distant states that choose to participate in trading agreements with a state—can have significant impacts on a state, a range of possible outcomes regarding state choices is examined.

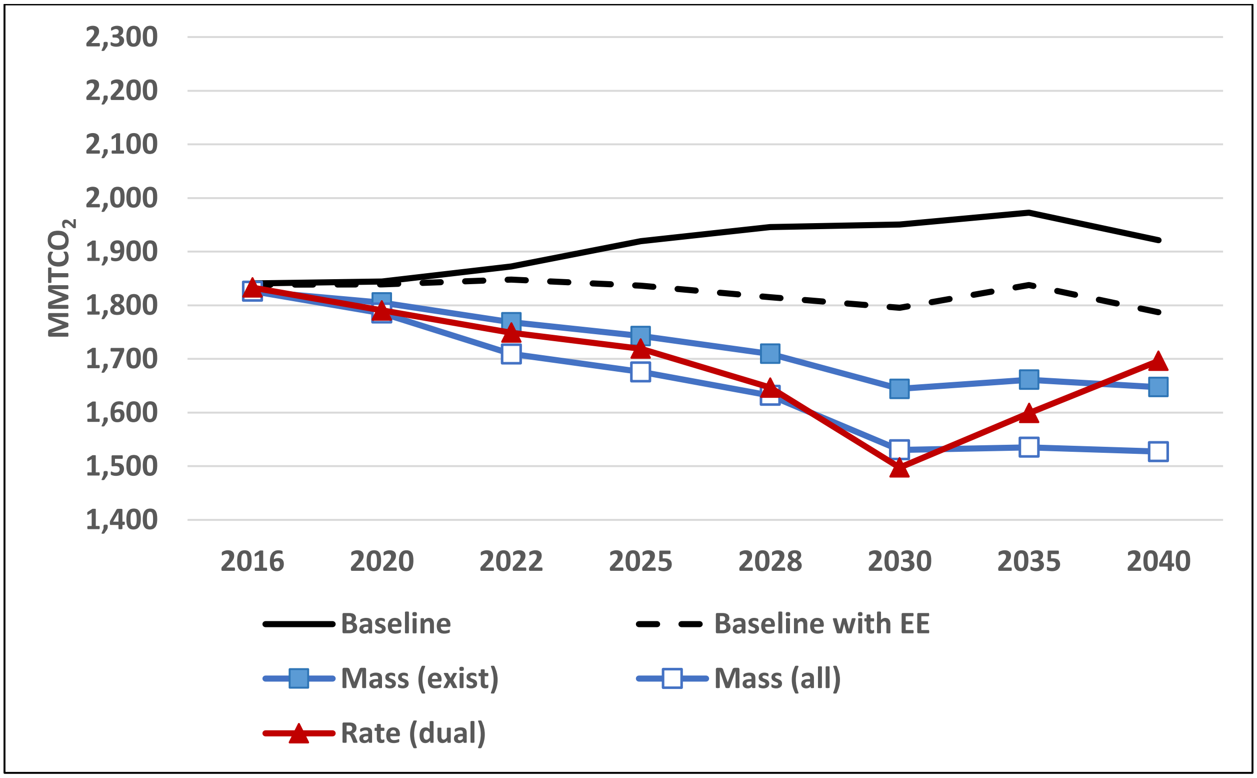
NATIONAL CPP POLICY RESULTS

The analysis of coordinated national approaches to the Clean Power Plan begins with an examination of their emissions projections, as compared to baselines without the policy. Generation impacts under the three policy scenarios are then presented. The generation changes are a useful metric to summarize the overall implications of changes across utilization, capacity through retirements and new construction, and plants' utilization rates. Fuel demands will also largely follow these generation patterns. The analysis next looks at some additional details of adjustments in the industry before examining regional policy costs across a range of sensitivities, some issues surrounding leakage of emissions from existing to new fossil units, and state patchwork scenarios.

CO_2 Emissions

Like baseline emissions changes, emissions impacts of the Clean Power Plan, aside from the mass cap with NSC option, which has a fixed cap on emissions, will depend on market conditions. Figure 9 compares the baseline emissions estimated using the standard assumptions, with and without EE measures, to the emissions from the three policy options under consideration.[11] By 2030, emissions have been reduced by some 26% as the result of a national mass approach covering existing units and by some 32% from the mass cap with NSC and dual-rate approaches. After 2030, a rate-based approach can lead to rising emissions as increases in renewable generation create additional ERCs, which can then be used to keep coal plants in operation.

Figure 9. U.S. electricity emissions under the standard baseline and alternative CPP approaches



The difference between the mass cap over existing units (-26%) and mass cap including new units through the New Source Complement (-32%) reflects leakage of emissions from existing plants to new plants that are outside of a policy approach covering only existing units. Similar emissions leakage to new NGCC units can occur under a rate-based policy but not under the standard set of assumptions (at least in the year 2030). As discussed in the section on leakage below, this equivalence in emissions (and lack of leakage) for the dual-rate option and the mass cap with NSC option may not hold for alternative assumptions about future trends.

Generation

Generation across the United States for the four categories of plants most affected by the policy—existing coal and NGCC units, new NGCC units, and existing plus new renewables (excluding biomass) units—is shown in Figure 10 for 2022—the initial year of the policy—and 2030—the year in which it is in full

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[11] Baseline emissions begin declining in 2040 as solar photovoltaic moves toward $1/watt and thus becomes an increasingly important generation source. If nuclear plants were to retire at about the same time after a 60-year life, they would largely be replaced by natural gas units, offsetting the emissions decrease from the market penetration of renewables.

effect.[12] Generation in the two baselines and the policy cases in this, and subsequent, figures, reflect DIEM's capability to choose the EE measures defined by the EPA as 1.0% per year off the previous year's demand, if it is cost-effective to do so. In many cases, DIEM fully adopts these measures at the prices defined by the EPA, assuming a 50-50 cost sharing between utilities and consumers and assuming that gas prices are at the standard "medium" gas price forecast (lower gas prices can make EE measures uneconomic in the baseline but economic in policy scenarios). This explains the difference in generation that results from lower electricity demand in the "baseline with EE" forecast, wherein demand is roughly 8% below that in AEO forecasts by 2030.

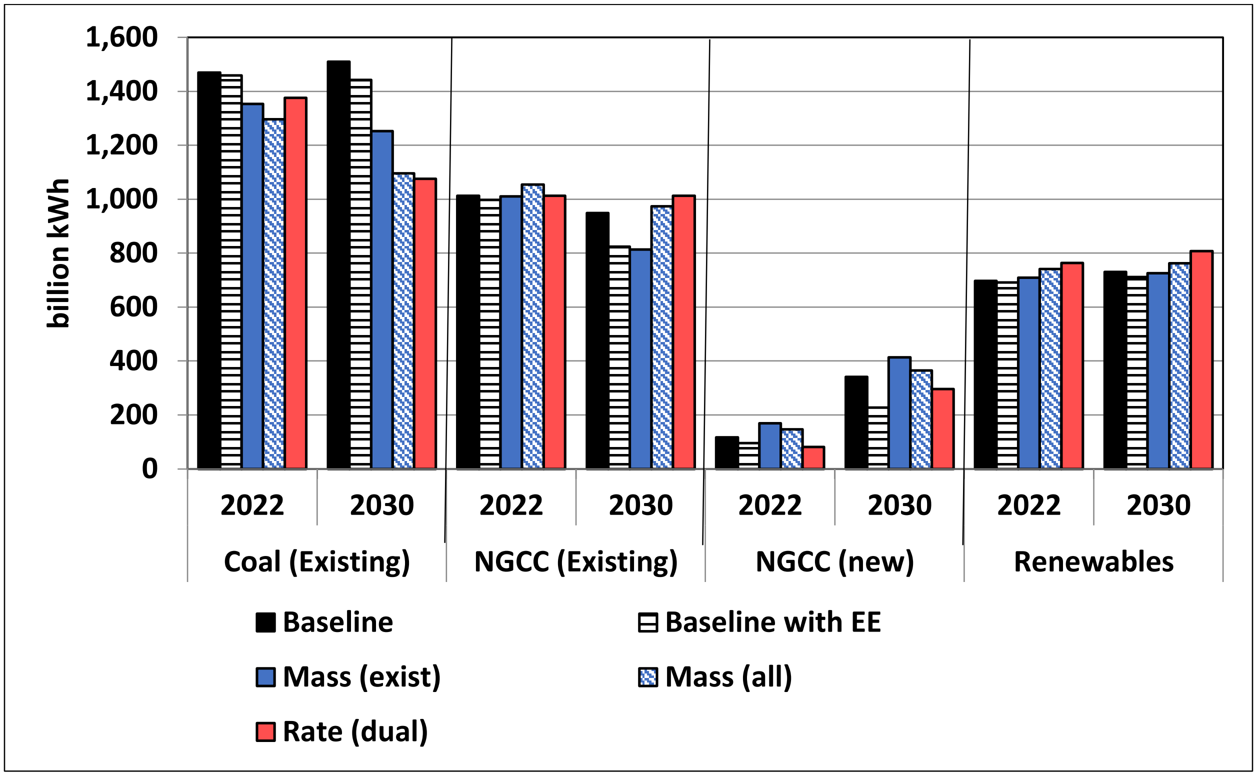
Under any of the three national policy options, coal generation drops slightly when the policy takes effect in 2022. More significant declines due to the policy are prevented because baseline coal capacity has already fallen to some 225 GW by 2022 as the result of low gas prices and environmental regulations such as MATS.[13] Coal continues to decline through 2030 under a mass cap over existing units approach, although the decrease is less than under a mass cap with NSC approach, which has higher allowance prices for CO_2 emissions.

The incentive structure implicit in the CPP emissions rate calculation is designed to encourage generation by existing NGCC units, which have lower emissions rates than coal units (and which provide gas-shift ERCs to coal units), and by zero-emitting renewables such as wind and solar. Although the model does not consider it economic to redispatch from coal units to existing gas units at the 75% rate used in the CPP calculation, there is an increase in generation from existing NGCC units in the dual-rate approach, compared to generation in a baseline including EE measures. A similar effect on existing gas units is seen under the mass cap with NSC policy, which discourages construction of new NGCC units by covering them in the policy's emissions cap. By contrast, a mass cap over existing units reduces generation by existing NGCC units and increases construction of new units (i.e., leakage).

A rate-based approach does encourage slightly more renewable generation than either of the two mass-based approaches, but the impact of its renewable incentive is relatively small for several reasons: (1) by 2020–2022, the extension of existing federal PTCs/ITCs has already increased renewable generation in the baseline (these units can provide ERCs in the CPP policy case), (2) comparatively low gas prices make it harder for renewables to compete, (3) EE measures that lower electricity demand tend to disproportionally and negatively affect renewables, and (4) fairly low ERC prices through 2030 limit the extent to which they can incentivize renewables (mass allowance prices are also low as discussed below).

[12] The model does not include biomass generation as an ERC-eligible renewable resource under dual rate compliance. Biomass generation emissions are assumed to be zero when total sector emissions are calculated.
[13] For comparison, total summertime coal capacity was 316.8 GW in 2010 (U.S. EIA 2015b).

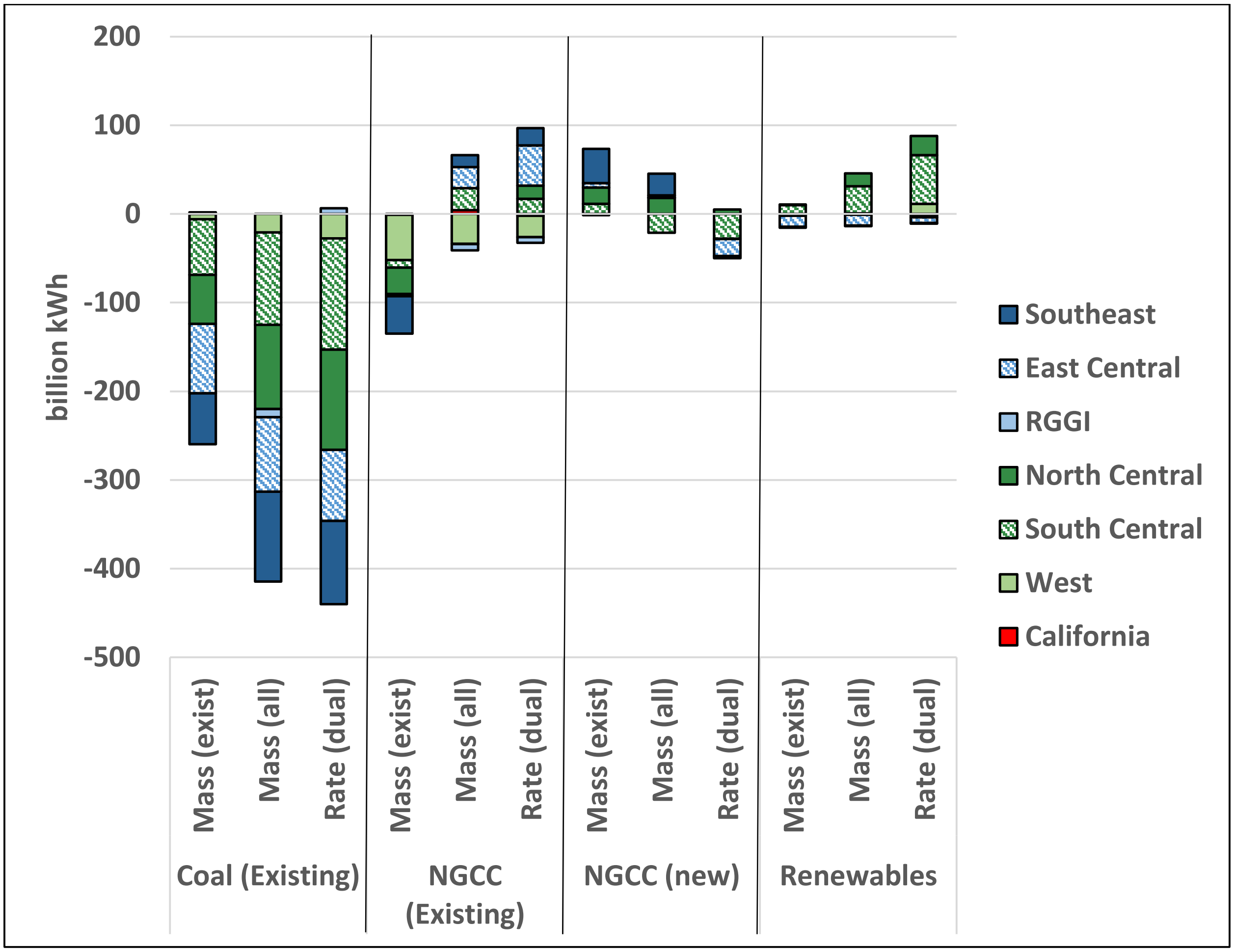
Figure 10. Generation in the baseline and under alternative CPP policy approaches



Note: Renewables excludes biomass sources.

Examination of regional details in the national policy results (Figure 11) reveals that although changes in U.S. coal generation are relatively similar in two of the three alternative policies, the location of generation changes can vary substantially. The South Central region, which shifts more heavily into wind generation in a rate-based approach, experiences larger declines in coal in this case. To a slightly lesser extent, a similar effect occurs in the North Central region. The Southeast and East Central regions, with fewer options for renewables, tend to rely on increased utilization of existing NGCC units, unless the policy is a mass cap over existing units and the Southeast and other regions move into new gas units.

Figure 11. Changes in regional generation, compared to a baseline without EE measures (2030)

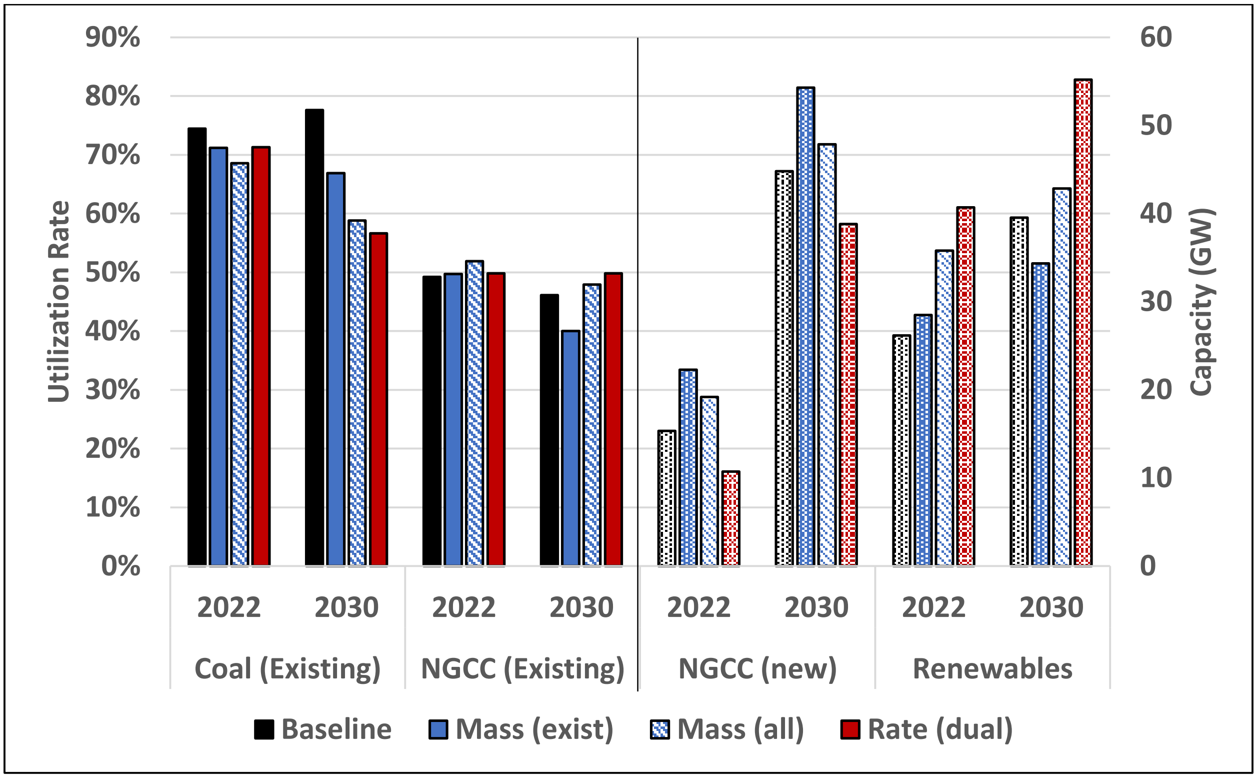


Capacity and Utilization

Although changes in generation cover many of the adjustments needed to respond to the Clean Power Plan, it is also useful to examine some additional information. The left-hand side of Figure 12 shows how utilization rates for existing coal and NGCC units changes; the right-hand side shows the total cumulative construction of new units. The redispatch of coal into existing gas units can be seen in the rate-based results; this effect disappears under a mass-based cap over existing units, which does not incentivize this shift. Coal utilization rates are affected more significantly in 2030 in the mass cap with NSC and rate-based options, which achieve the most overall emissions reductions.

Construction of new units, measured in GW, is significantly different in the rate-based option than in the mass-based options. The rate-based option favors additional renewables, whereas the mass cap over existing units emphasizes new NGCC units. Because renewables have utilization rates that average 30% to 35%, their level of construction is not directly comparable in generation terms to the new NGCC units, which tend to run as baseload units in the model at the maximum availability rate of 87%.

Figure 12. Existing-unit utilization rates and new capacity



Policy Costs of National Approaches

Policy costs encompass 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 (these are typically annualized for cost-reporting purposes); fixed operations and maintenance (O&M) costs that represent annual maintenance expenditures; variable O&M costs, which vary with the level of generation; and fuel costs. Other types of costs such as ERC purchases or 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, but they can affect regional policy costs. Like other electricity dispatch models, DIEM minimizes policy costs for the nation as a whole over its entire time horizon, which runs through the 30-year book life of new units installed in 2060. This long-term approach to cost minimization can lead to short-term policy cost results that move counter to long-term results.

From a state or regional perspective, additional costs and benefits are associated with importing or exporting electricity. The assumption underlying this analysis' reported policy costs is that 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 and ERCs to other states under national or 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 EE measures paid by both utilities and consumers are also factored into the cost reporting.

As a general rule, flexibility in any form will always lower costs as utilities seek out cost-effective policy responses. The CPP design provides several cost-lowering forms of flexibility: states can count EE measures and renewables toward compliance under the rate-based approaches and, importantly, act in concert with other states to take advantage of low-cost reduction options across regions (locational or "where" flexibility). During at least the first decade of the policy, states can also smooth adjustments over time (temporal or "when" flexibility) as they move toward final emissions goals in 2030.[14] Because DIEM operates with foresight, construction decisions will be optimal as utilities plan for future needs and take advantage of any available cost-saving flexibility, which will affect policy costs and investment patterns.

Before the policy costs of alternative scenarios can be compared, the elements considered part of the model's baseline forecast must be identified. As discussed above, the EE measures included in the model are typically a cost-effective alternative to electricity generation—whether or not the CPP policy is in place, leaving open the question of which baseline costs should be measured against policy costs. Allowing EE measures in the model's baseline means their apparent cost savings are not attributed to the policy, and thus any such savings are not factored into the incremental cost differences between the baseline and the CPP policy.[15] As a result, estimated policy costs will be higher than they would be under the alternative assumption that the EE cost savings are brought about only by the policy.

Figures 13–15 illustrate the described policy costs for national approaches to the Clean Power Plan (with RGGI and California separately pursuing a mass cap with NSC, regardless of other states' actions). In these figures, the cost metric is the change in the present value of costs through the year 2040 compared with baseline costs.[16] The types of costs (listed in the figure legends) are divided up into changes in capital, O&M, and fuel costs, along with regional expenditures on net electricity imports, EE measures, and regional trade in mass allowances or ERCs. Increases in costs are shown above the zero line, while "benefits" or negative costs are shown below the zero line (for example, RGGI exports more electricity into the East Central region than it imports and thus a negative net import value—or increased net export value—is shown).

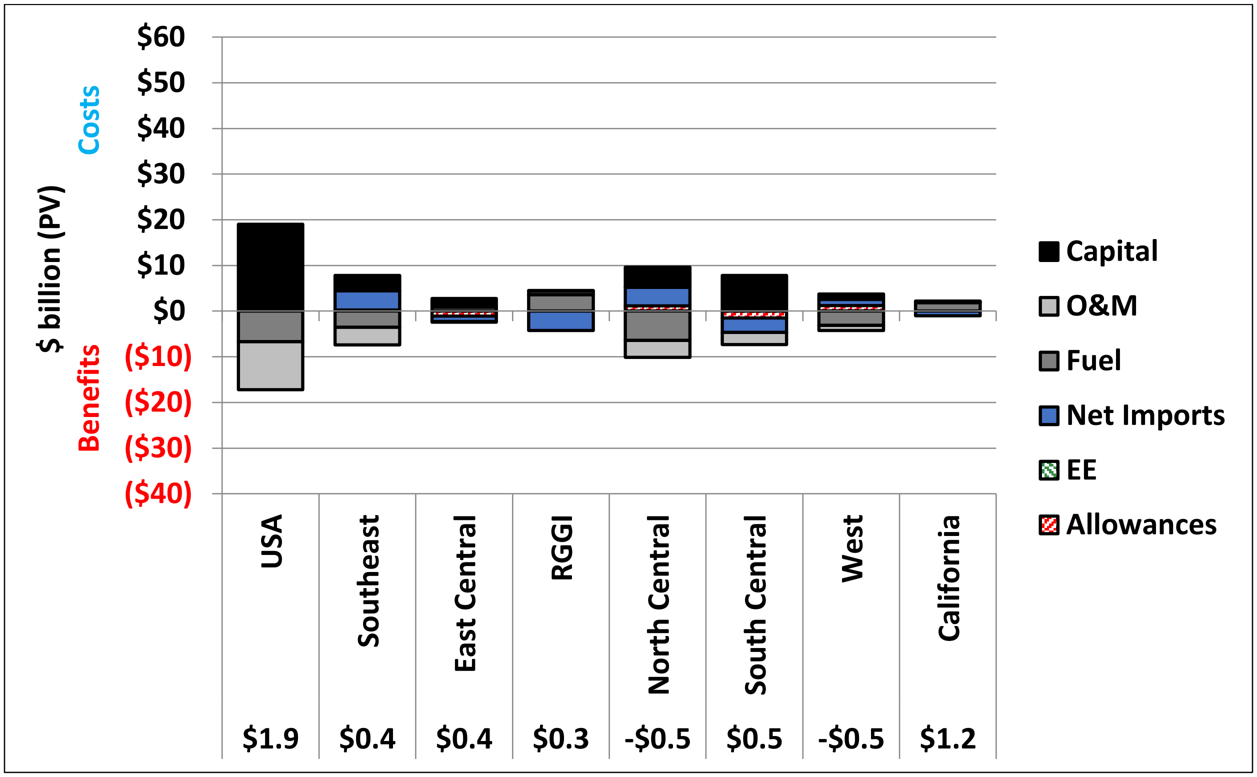
For the nation as a whole and given the standard set of assumptions in DIEM, costs for a policy focusing on a mass cap over existing units are extremely modest at $1.9 billion in present value terms (shown below the USA label on the left-hand side of Figure 13). These costs reflect increased capital investments in renewable and new NGCC generation and corresponding declines in operating and fuel expenses of existing units. At a national level and compared to the baseline, there are no net changes in electricity trade flows or trade in mass allowances and no additional expenditures on EE measures. The Southeast, and to a lesser extent the North Central region, rely on additional imports of electricity to meet their needs, while other regions such as the South Central area (with its access to wind resources) help supply these needs. Wind investments in the South Central region show up as a positive increase in capital costs. In other regions, for example, California, there may occur different types of interactions, such as a slight increase in natural gas prices as demand rises, leading to additional fuel expenditures.

Some regions (and states) may experience cost increases, whereas others may be slightly better off as the result of factors such as extra income from electricity exports, declines in costs of electricity imports, and profits from the sale of allowances in mass-based policies (or ERCs in rate-based policies). The model does not estimate how these benefits will be distributed among electric utilities, independent power

[14] It is assumed that temporal flexibility, i.e., the banking of ERCs and allowances, ends in 2030 and that policy goals are met on a five-year basis in subsequent years.
[15] The same is also true of allowing coal-unit efficiency retrofits in the baseline, although such retrofits occur less often in the baseline and have little effect on reported policy costs.
[16] Although the modeling optimizes costs over a longer time horizon, the results show changes in costs (in present value terms) either through the first couple of decades of the policy as a compromise between the time frame of interest to policy makers and electricity generators and the longer horiizon underlying the structure in the model.

producers, or electricity consumers. If a region builds a wind plant, its "costs" reflect the associated capital expenditures, and the region is then credited with any resulting sales of wind electricity to surrounding regions. In addition, if the wind unit allows a coal plant retirement, the region can sell any freed-up allowances to other areas. This benefit can be seen in the benefits side of the ledger for the South Central region.

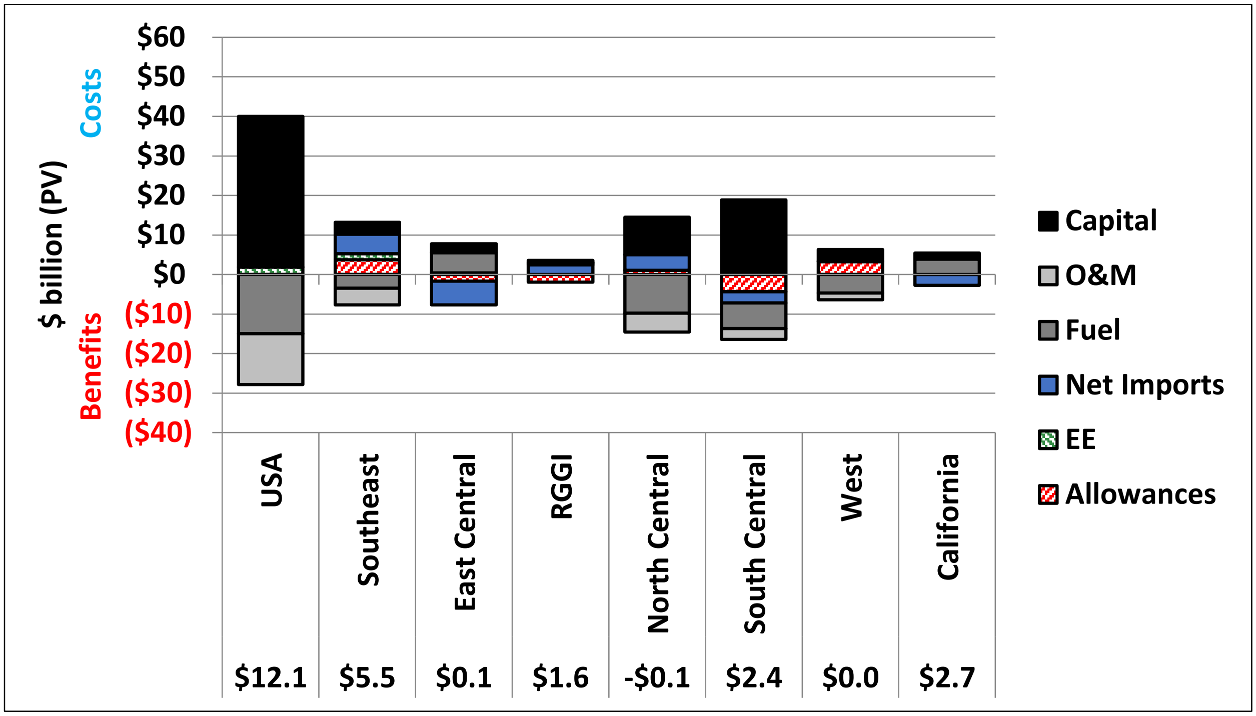
Figure 13. Policy costs for national mass cap over existing units (change in present value to 2040)



Compared with a mass-based policy covering only existing units, the NSC option (shown in Figure 14) is more expensive, although the difference is small in percentage terms (see Figure 16), and its emissions reductions are substantially greater. In addition, its allowances prices are higher (see Figure 17), and its incentive to trade allowances across regions to achieve the lowest possible costs is greater. Some additional shifts in electricity flows occur under a mass-based policy covering only existing units—for example, RGGI's electricity exports to the East Central region increase—but they would decrease if the East Central states also adopted the NSC.[17] The South Central region increases its investment in wind, leading to additional capital expenditures. California does the same at home and reduces the amount of its net electricity imports. The Southeast, which has a comparatively difficult time achieving low-cost emissions reductions, incurs the cost of importing allowances.

[17] RGGI adopts the NSC caps in both the mass cap covering only existing units and the mass cap covering all units. What changes are the actions taken by its neighbors.

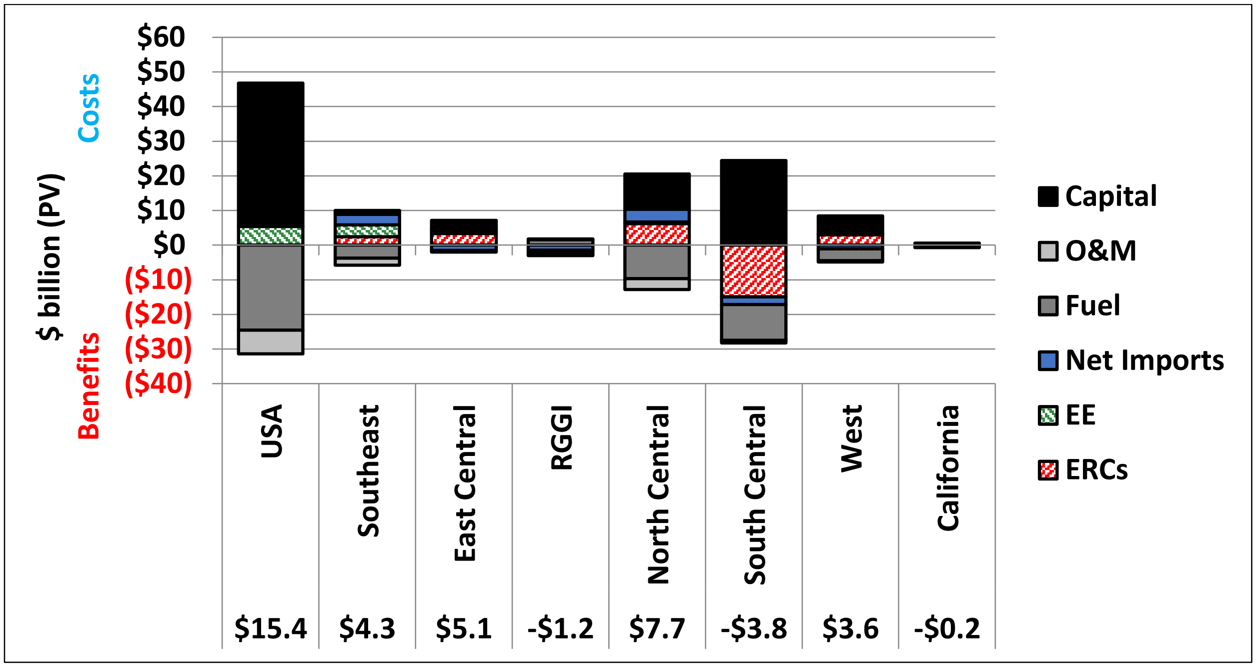
Figure 14. Policy costs for national mass cap over all units (change in present value to 2040)



A dual-rate approach to the Clean Power Plan (Figure 15) has costs roughly equal those of the mass-based approach covering all units (and achieves similar emissions reductions, at least through 2030). But compared with the mass-based options, the dual-rate approach has costs less evenly distributed across regions. The South Central region benefits from the sale of ERCs generated by its additional wind generation.[18]

[18] Given the capital costs in DIEM's standard set of assumptions, solar PV generation plays a relatively limited role in providing ERCs through 2030.

Figure 15. Policy costs for national rate with dual targets (change in present value to 2040)



Sensitivity Analysis of National CPP Policy Approaches

Sensitivity analysis of the standard set of assumptions about future market conditions is a useful way to evaluate how much confidence should be placed in any single point estimate of future costs. Figure 16 presents regional cost changes in percentage terms across the above-described range of alternative assumptions. Given the standard set of assumptions, the mass cap over existing units (left-hand column in the figure) has nearly zero costs for most regions. One exception is California, which incurs costs of some 1%, even though its mass cap with NSC policy is non-binding within the state in most years. Even though the mass limits under the NSC are tighter for California than for neighboring states, which are pursuing the looser mass cap over existing units, some of those states' costs are shifted to California—a phenomenon highlighting that any given state's costs can be in part a function of the choices made by a state's neighbors.

Low gas prices put policy costs at essentially zero, implying that the Clean Power Plan is non-binding and that its emissions goals can be met without significant adjustments if gas prices are sufficiently low. But high gas prices result in comparatively much higher policy costs, although they remain low as a percentage of total expenses in the industry. Across all three policy options, high gas prices also lead to a much wider dispersal of regional costs, particularly in California, because it tends to rely on gas generation, both within the state and through imports from neighboring states. Other regions such as RGGI also can rely on gas generation, which is disadvantaged by high prices.

High electricity demands are not a particular difficulty if the policy covers only existing units because the additional generation needs can be met through construction of new NGCC units that are outside the policy. In a somewhat similar fashion, the dual-rate approach provides room for additional demand growth. The mass cap with NSC that covers all fossil generation can be costlier than projected if electricity demands prove to be higher than anticipated. That possibility illustrates the relative ineffectiveness of the leakage provisions in the CPP Final Rule. In the context of the mass-based policy covering existing units, those provisions' output-based allocations for existing NGCC units and allowance set-asides for renewables are supposed to counteract the desire to shift to new NGCC generation.

Low capital costs for renewables have relatively little impact on the costs of the mass-based policy options. As might be expected, cheap wind and solar are most beneficial under a rate-based approach whereby they can contain the costs of ERC purchases in regions with relatively few renewable sources. ERC sales can be seen across all the rate sensitivities for the South Central region, which can produce wind ERCs for sale at prices that are lower than the costs of constructing the wind units. Low EE availability has relatively little impact on the mass policy over existing units, but it makes the mass policy over all units approximately twice as expensive for the United States as a whole because the additional demand it creates is largely met through new NGCC units that are covered under the NSC. Similarly, limited EE measures increase the difficulty of generating the ERCs needed to meet the requirements of a rate-based policy, raising costs. Policy scenarios with high EE availability (1.5% per year of baseline demand) could reduce policy costs across all three approaches to essentially zero given the assumed EE costs from the EPA data.

Figure 16. Policy cost sensitivity analysis (change in present value to 2040 versus the baseline)

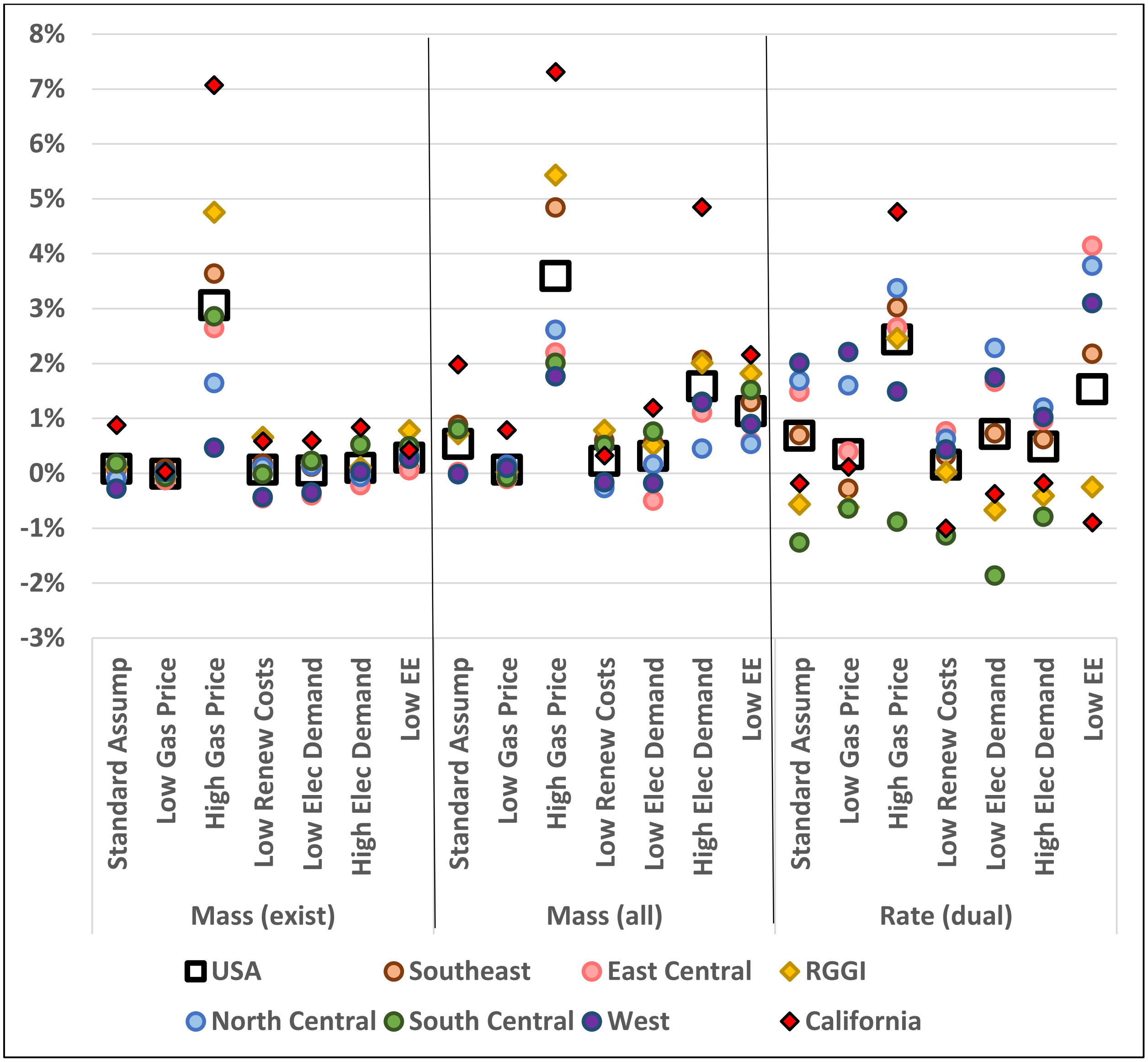
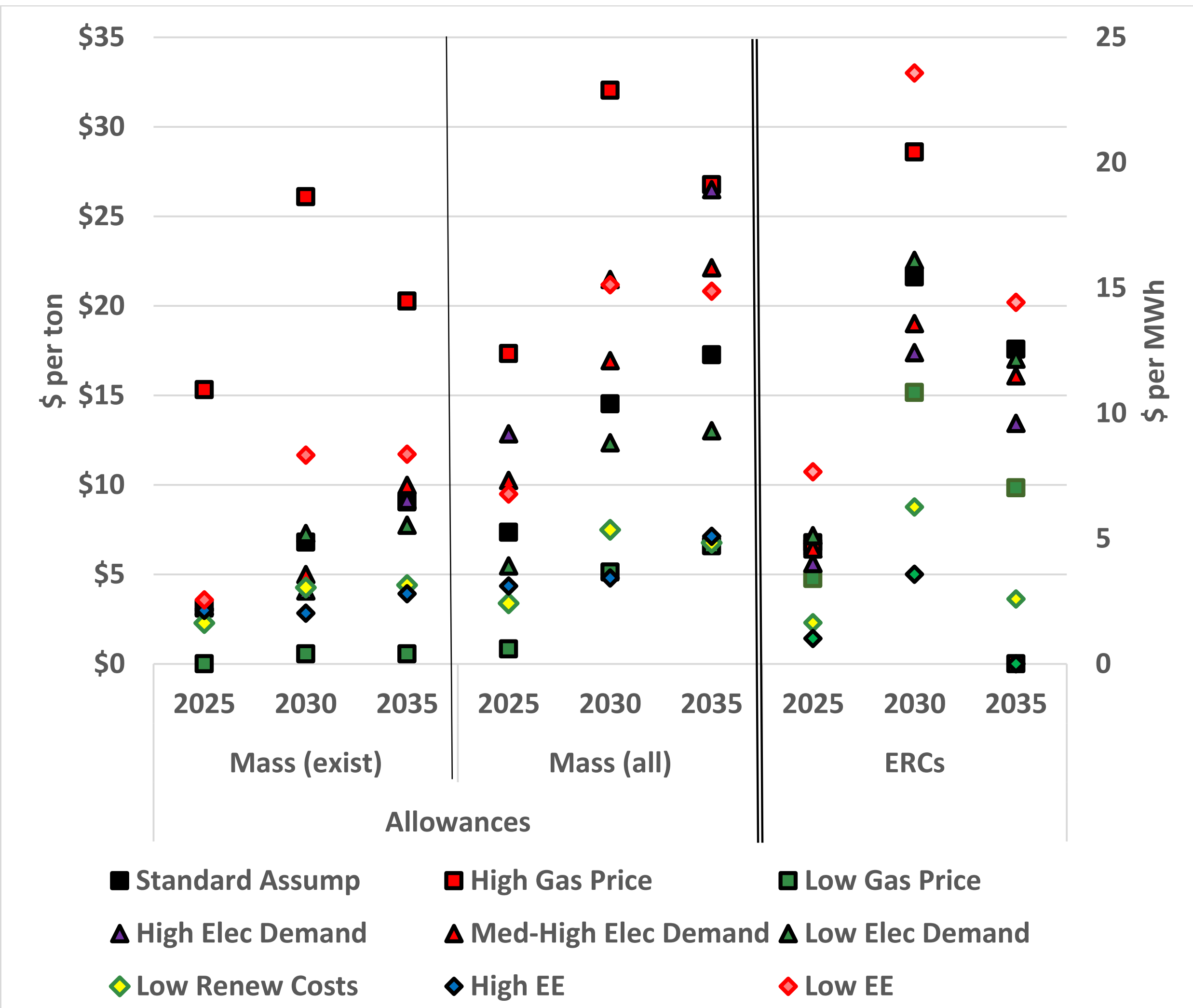


Figure 17 illustrates how mass allowance and rate ERC prices vary across the sensitivity cases and over time. Allowance and ERC prices reflect the cost associated with the highest-cost option taken in response to the policy, that is, the action on the margin that just allows a region to meet its emissions goals. The mass allowance prices on the left-hand side of the graph, shown in dollars per metric ton of CO_2, and the ERC prices on the right-hand side of the graph, shown in dollars per MWh, are not interchangeable because they are expressed in different units and created in different ways; allowances are allocated in some fashion as part of the policy, whereas ERCs are produced by running renewable plants, some nuclear plants, and existing NGCC units, along with any gas-shift ERCs associated with those units. In addition, within the two types of mass allowances, the price for the mass policy over existing units is incurred only for emissions of existing units, whereas the price for the mass policy over all units is incurred for emissions from (almost) all fossil plants.

In most cases, the mass allowance prices are fairly low relative to those shown by analyses for economy-wide climate policies. These prices are largely bounded by gas price sensitivities; low gas prices result in low (or zero) allowance prices, implying that the Clean Power Plan can be non-binding in some years, whereas high gas prices result in high allowance prices because those allowance prices are being set by the existing and new NGCC units that operate on the margin. In between these extremes, low EE availability results in comparatively high allowance prices, and the reverse is true for high EE availability. Although not fully demonstrated in Figure 17, allowance prices for the mass policy over existing units move toward zero by 2040 as retiring units are replaced by new generation. Prices for the mass policy over all units generally rise slightly as electricity demand grows.

ERC prices follow a pattern somewhat similar to that of mass allowance prices—with some exceptions. Low availability of EE measures can raise ERC prices by forcing ERCs to come mainly from new renewable generation, the costs of which are greater than the assumed costs of EE measures. Low gas prices have less effect on ERC prices than mass allowances. Because high EE availability can offset the need for renewables to produce ERCs, it can decrease prices. Like allowances for a mass policy over existing units, ERC prices move toward zero by 2035 in some cases and by 2040 in others.

Figure 17. Policy allowance and ERC price sensitivities



Generation across the Sensitivity Scenarios

The country's mix of coal and natural gas generation, along with overall levels of renewables available to offset the need for fossil generation, will control how successful the Clean Power Plan is at reducing emissions. The caveat is that the mass cap with NSC approach places an absolute upper bound on emissions from most fossil sources—an upper bound that the industry can use to choose the most cost-effective mix of coal, gas, and renewables. Figures 18–20 examine how generation in 2030 responds to changes in market conditions under the three policy alternatives: a mass cap over existing units, a mass cap with NSC, and the dual-rate.[19]

Several findings are broadly consistent across all three policy options. First, for the standard set of market assumptions, the Clean Power Plan essentially reduces coal generation without affecting gas generation. What varies is the amount to which coal generation drops.[20] Given the standard set of assumptions, a mass cap with NSC and the dual-rate result in a comparable coal-gas mix and hence a similar level of emissions reductions (see Figure 22 for alternative results). Low EE availability in the policy case increases gas generation by some 250 TWh, whereas high EE availability reduces it by approximately 500 TWh. Cheap renewables reduce gas generation and increase coal generation, although the magnitudes vary significantly. Finally, low or high gas prices move the generation mix in the expected directions.

Under the mass cap over existing units and across all sensitivities, the amount of coal generation changes little, but gas generation tends to respond to the alternative market conditions. The dispersion of the coal-gas mix is also more contained than under the other two policy approaches, which achieve significantly more emissions reductions in 2030. In most cases, the mass cap over all units reduces coal generation below the generation that would be realized by baseline trends, including low gas prices, in the industry. Although most sensitivities move in the same direction under the mass cap with NSC and rate approaches (and to a lesser degree also in the mass cap over existing units), one exception is changes in electricity demand. Lower electricity demand shifts the mass cap with NSC policy toward coal generation as the decline in demand lowers allowance prices (see Figure 17) and makes coal units more cost competitive. Conversely, high demand under a mass cap with NSC policy causes a dramatic increase in gas generation at the expense of coal as the higher electricity needs require more new generation and increase allowance prices, thus favoring natural gas. Because total emissions are not fixed in a dual-rate approach, high electricity requirements lead to an increase in both coal and generation, without favoring natural gas.

[19] Three baseline mixes related to different gas prices from Figure 7 are also shown for comparison. These mixes, which are baselines without EE measures, span much of the likely range of mixes in the absence of the CPP policy.
[20] The standard assumptions underlying this baseline point (the black square) include the medium gas price forecast and the absence of the EE investment option (see Figure 7).

Figure 18. Fossil generation for a mass cap over existing units: alternative future trends (2030)

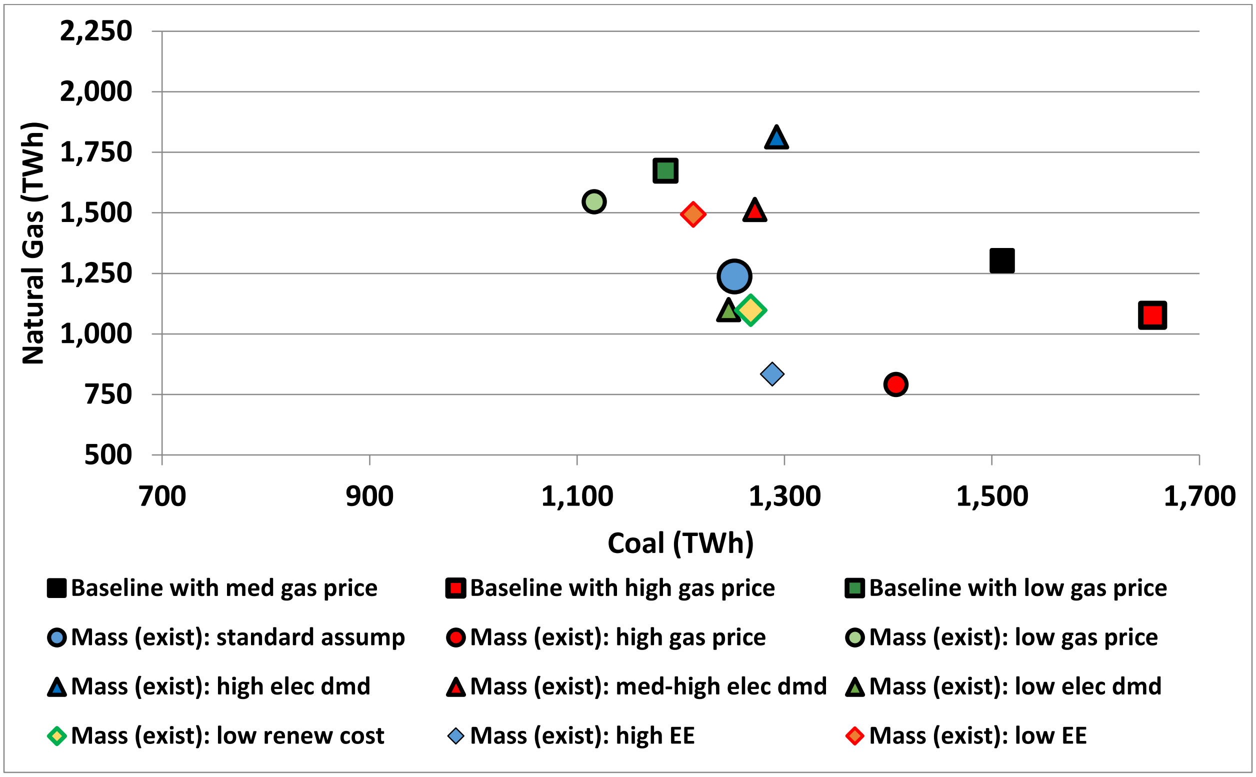


Figure 19. Fossil generation for a mass cap over all units: alternative future trends (2030)

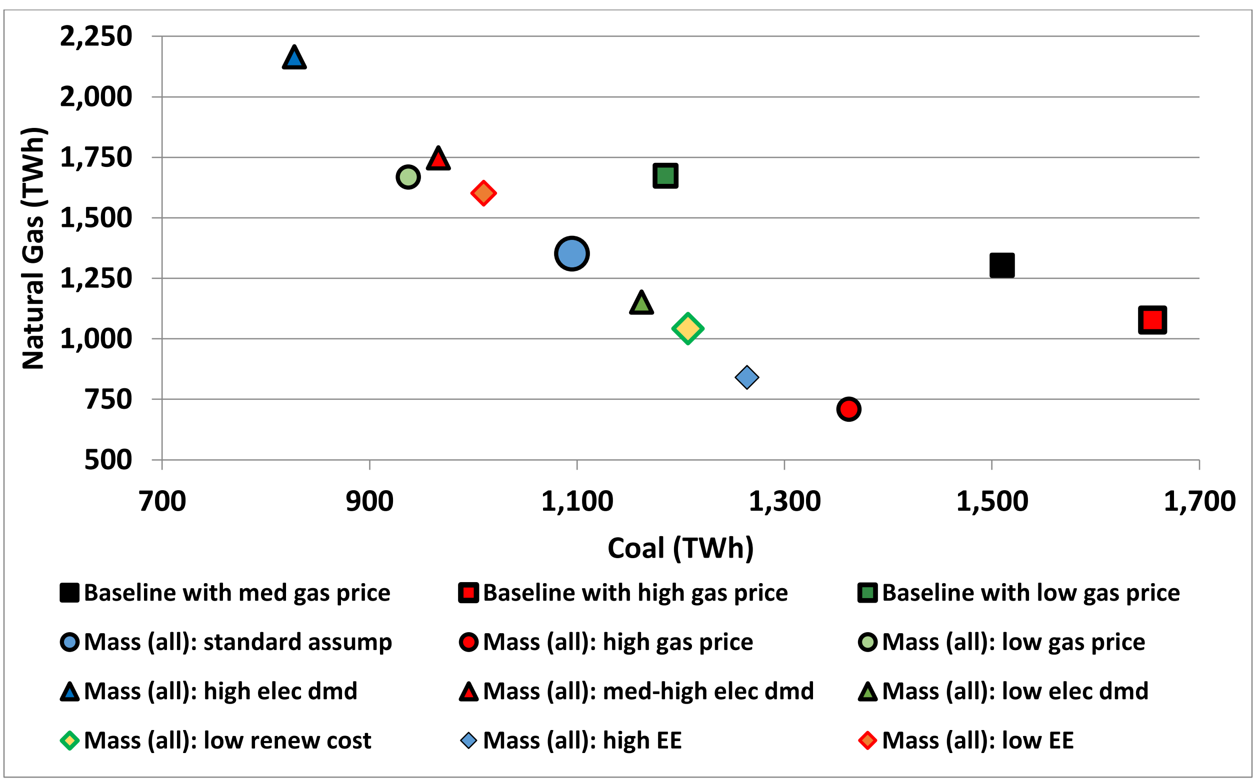
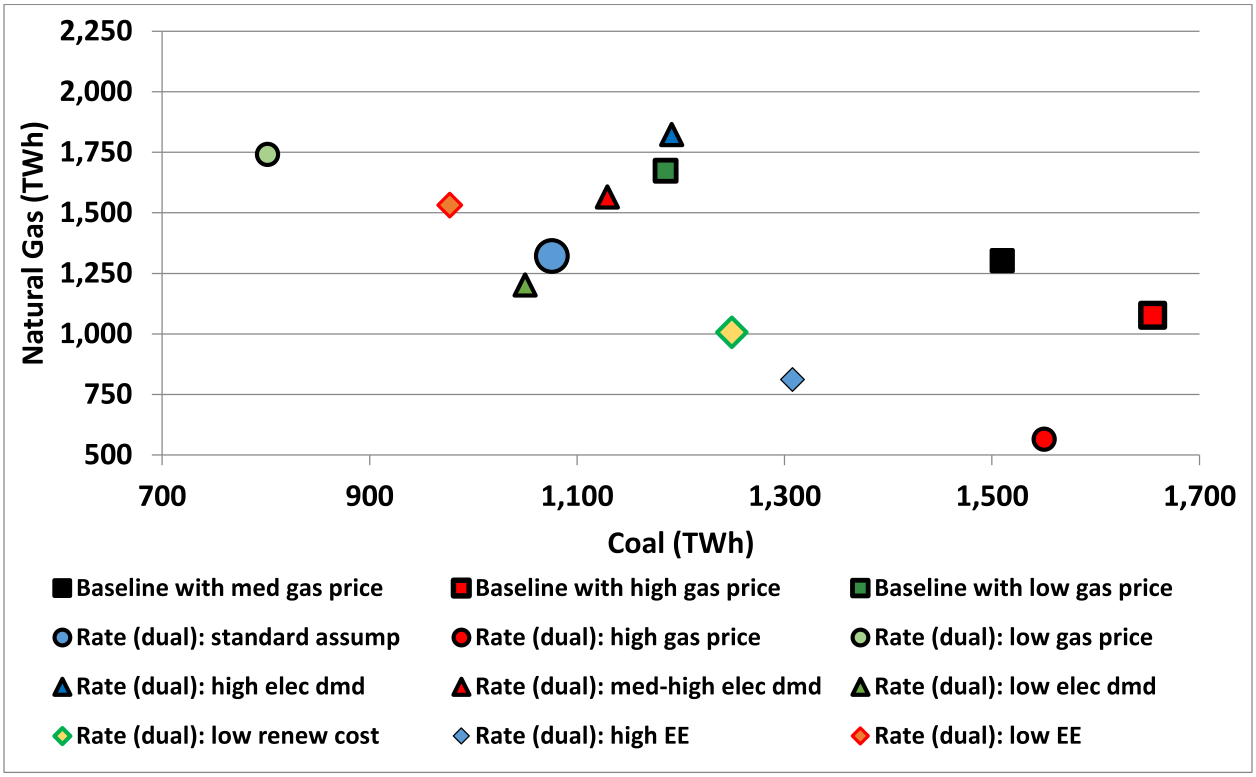


Figure 20. Fossil generation for dual-rate: alternative future trends (2030)



The importance of renewable generation in the future is a function of both policy choices and market conditions. Figure 21 shows regional changes in generation for alternative assumptions.[21] The mass policy over existing units, which has comparatively little impact overall and very low allowance prices, does little to encourage additional renewables with one exception, which also holds for the other two policy options. In the case of high gas prices, the policy's allowance prices increase, as do the costs of new gas generation. The majority of renewables that are built by 2030 are usually grouped in the South Central and North Central regions, which have access to relatively abundant wind resources. After 2030, or beforehand if solar PV costs decline more rapidly than expected, dispersion of renewables outside areas with wind generation can be expected to increase as solar resources gain importance as a policy response.

The mass policy over all units encourages more renewables than a more limited mass approach. Under this policy, several factors can substantially increase renewable generation: increased electricity demand, decreased renewables costs (i.e., solar PV at approximately $1/watt), or limited EE availability, which has the same effect as increased electricity demand. The dual-rate policy tends to incentivize the most renewables, which can create ERCs for fossil units. This phenomenon holds if gas prices are high, or especially if EE availability to provide ERCs is low. But unless solar PV generation becomes a more economic option, some areas of the country such as the RGGI states and the East Central region are unlikely to see significant renewables penetration.

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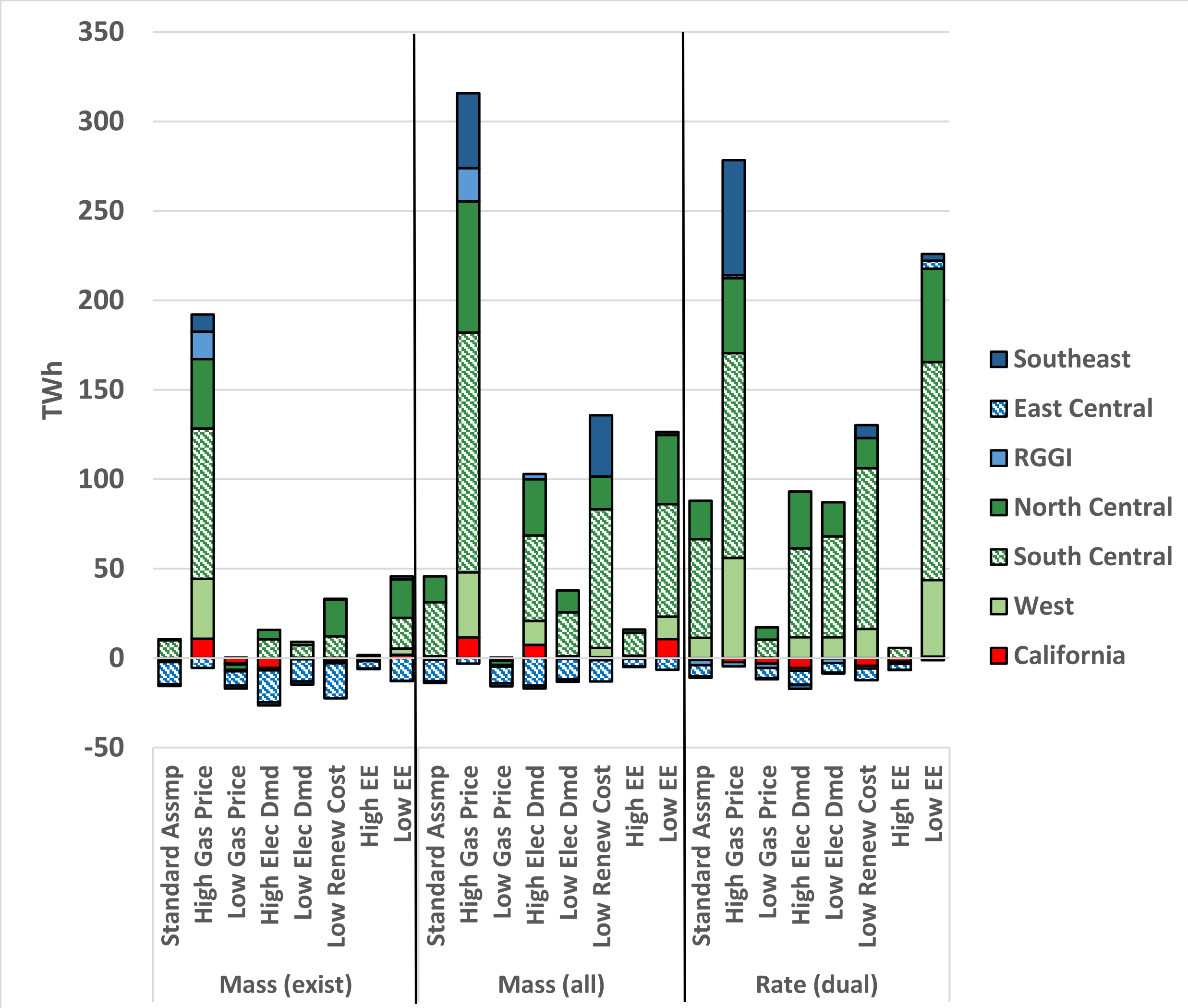
[21] The changes are in reference to a baseline that does not include EE measures. Thus, the need for renewables can decline in policy cases that include these measures, particularly in the East Central region.

Figure 21. Changes in regional renewable generation: alternative future trends (2030)

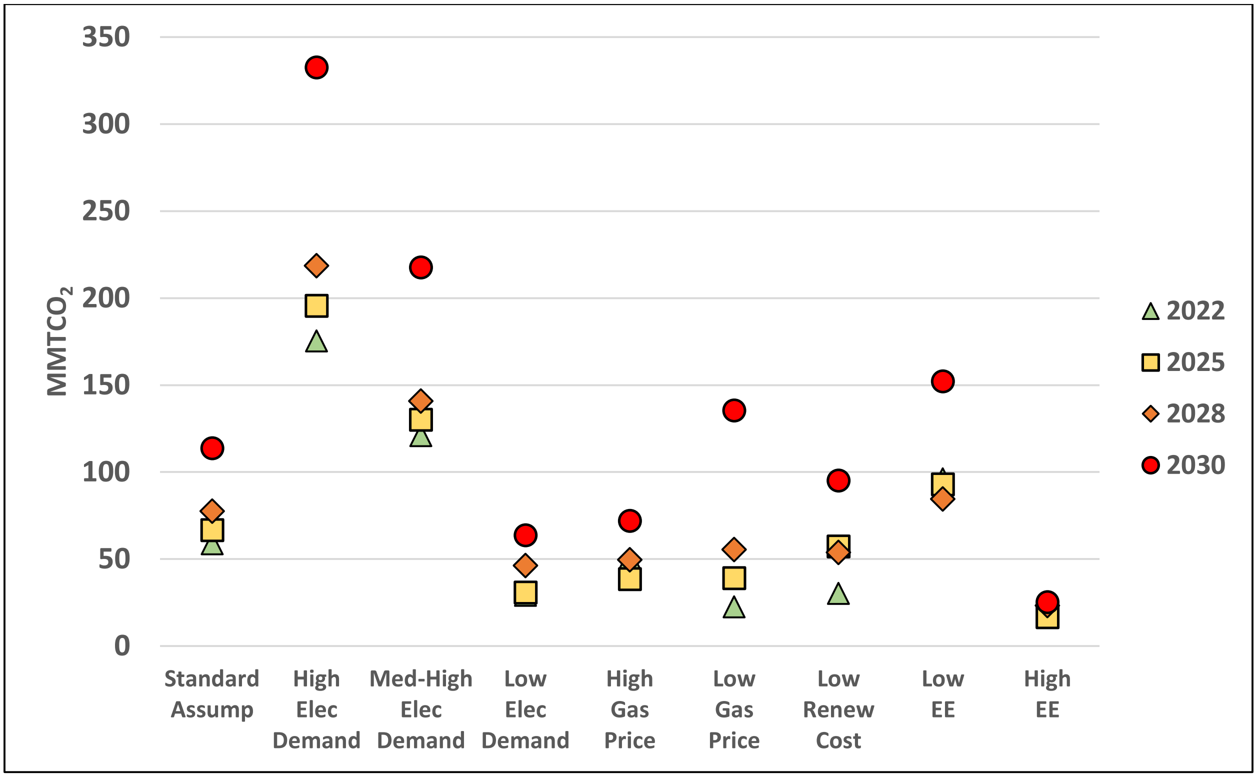


Leakage of Emissions to New Units

One concern regarding the Clean Power Plan is the possibility of emissions leakage, whereby fossil sources not covered by the policy increase their emissions, thus reducing the policy's effectiveness. The mass policy with NSC, which has a fixed emissions cap that covers (essentially) all sources, represents a known quantity of emissions, regardless of how future market trends may affect the evolution of the industry. Neither the mass cap over existing units nor the dual-rate approach represents a known quantity of emissions. The mass policy covering existing units contains provisions to help offset leakage to new sources by encouraging generation by existing NGCC units and renewables. However, these output-based allocations and renewables set-asides have little effect on generation choices because their value is determined by the comparatively low allowance prices shown in Figure 17. The dual-rate policy—given the standard set of assumptions about market conditions—results in little leakage to new units compared with the mass policy with NSC, although not in all circumstances.

In Figure 22, leakage is defined as the difference between emissions under a mass cap over existing units and the fixed emissions of the NSC. Figure 23 shows the calculation for the dual-rate approach. Given the standard assumptions, leakage by 2030 is some 115 $MMTCO_2$, or 7%, of the NSC cap. Under the dual-rate approach, trends in electricity demand growth are the most important determinant of leakage. Moderately or very high electricity demand growth can double or triple the amount of leakage as increased electricity needs are met through new NGCC units outside the approach's coverage. High natural gas prices can discourage new gas generation and limit leakage, whereas low gas prices can reverse these effects. High electricity demand as the result of low EE availability can increase leakage, and the reverse is true for high EE availability.

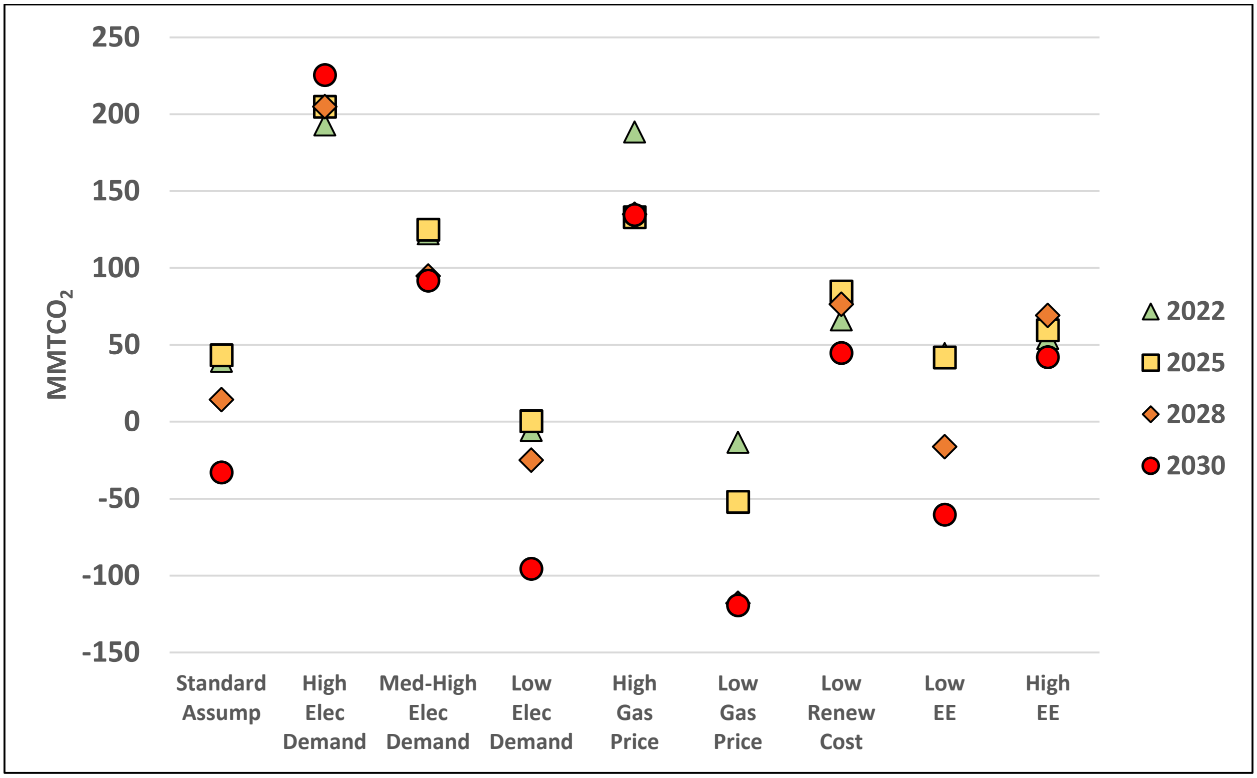
Figure 22. Leakage of a national mass cap over existing units



Given the standard assumptions in the analysis, leakage under the dual-rate policy, compared to leakage under the mass cap with NSC, is relatively limited, as shown on the left-hand side of Figure 23.[22] However, nothing in the policy parameters of a rate-based approach ensure this outcome because emissions can grow or shrink with the types and amount of chosen generation. Thus, high electricity demand growth can lead to additional leakage under the dual-rate policy. Conversely, low demand growth could potentially leave emissions below that of the NSC (as shown by the negative numbers in the graph). Interestingly, low renewables costs lead to creation of additional ERCs, which allows coal units to continue operating, thus raising emissions and leakage. Limited availability of EE measures would work in the opposite direction by restricting the supply of ERCs. Fortunately, increased EE availability does not necessarily cause significant additional leakage.

[22] After 2030, leakage under the dual-rate approach significantly increases, as can be seen in Figure 9.

Figure 23. Leakage under a national dual-rate policy



STATE-LEVEL IMPACTS AND PATCHWORK POLICIES

This section begins with an examination of the state-level policy costs and ERC/allowance trading patterns associated with the "national" CPP policy options. Given the significant impacts on a state of the actions of neighboring states—and of any more distant states that choose to participate in broad trading agreements, findings are used to specify a range of patchwork approaches to the Clean Power Plan. For simplicity, the analysis focuses on the eastern half of the country, covering largely the Eastern Interconnection and ERCOT, and it investigates how states may be inclined to adopt approaches to meet emissions goals that result in the least costs to themselves rather than to the national grid. Some states may be well positioned to generate, and perhaps sell, ERCs. Other states may have a difficult time meeting emissions rate goals and thus may lean toward a mass-based approach.

State Policy Costs of National Approaches

State-level CPP policy costs depend on a wide range of factors, including a state's emissions goals, existing generation fleet, and capacity to construct renewable generation—and, importantly, how the model used in the analysis goes about estimating state-level impacts. To determine localized policy effects, the model must have the capability to reflect data on existing and potential new units by state, to assign new generation to specific states rather than to a region, to forecast electricity demand at the state level, and to specify transmission constraints in a way that allows estimation of electricity trade among states. These data and capabilities affect the model's cost-minimization decisions in supplying electricity to the national grid. That said, electricity dispatch models are not attempting to find the lowest-cost alternative for a specific state or group of states or to evaluate the possible outcomes of any political processes accompanying interstate or intra-utility/inter-utility coordination.

To some extent, the patchwork scenarios in this investigation move closer to a situation in which it is possible to use model results to evaluate what may be in an individual state's best interests. Multiple caveats accompany these state cost estimates. First, the estimates assign the costs (and benefits) of constructing new generation to the state in which the unit is located, rather than attempting to disburse them across electric utilities' service areas. Any changes in the flows of electricity across states associated with these new units or retirements are valued (at wholesale electricity prices) when determining a state's benefit from, for example, new construction that is used to export electricity to surrounding states. Similarly, the costs of renewables built in a state and associated potential benefits of any ERC sales to other states is assigned to the original state, rather than disbursed across groups of states.

Exports of electricity and ERCs can lead to negative costs, that is, benefits from the CPP policy, in some states and regions. Again, the model is not estimating how these benefits will be distributed among electric utilities, independent power producers, or electricity consumers. Moreover, although intra-state factors largely drive broad trends and large impacts, but small variations can be affected by plant location decisions, obscuring real-world factors that might lead to different outcomes. In addition, neighboring states' costs that move in different directions or have different magnitudes may be smoothed out through the cost-assignment mechanisms of utilities or electricity service areas covering multiple states.[23]

Figure 24 shows estimated policy costs at the state level for the "national" mass cap over existing units using the standard assumptions in the model.[24] For the states in light green, the CO_2 allowance price is $6.8/ton in 2030 (see Figure 17). In the California market and in the RGGI market, the allowance price is $0/ton in 2030 given the comparatively low natural gas prices reflected in the model's standard assumptions. That price implies that California could meet its NSC emissions cap without taking additional action in response to the Clean Power Plan. The same is true for the RGGI states (although higher gas prices lead to positive allowance prices in the RGGI region).[25] However, overall CPP costs in these states are not guaranteed to be zero because the costs are affected by the actions of neighboring states. California relies on electricity imports to help meet its demand, and RGGI interacts with surrounding states. In addition, its member states are affected by some minor inter-RGGI cost shifting.

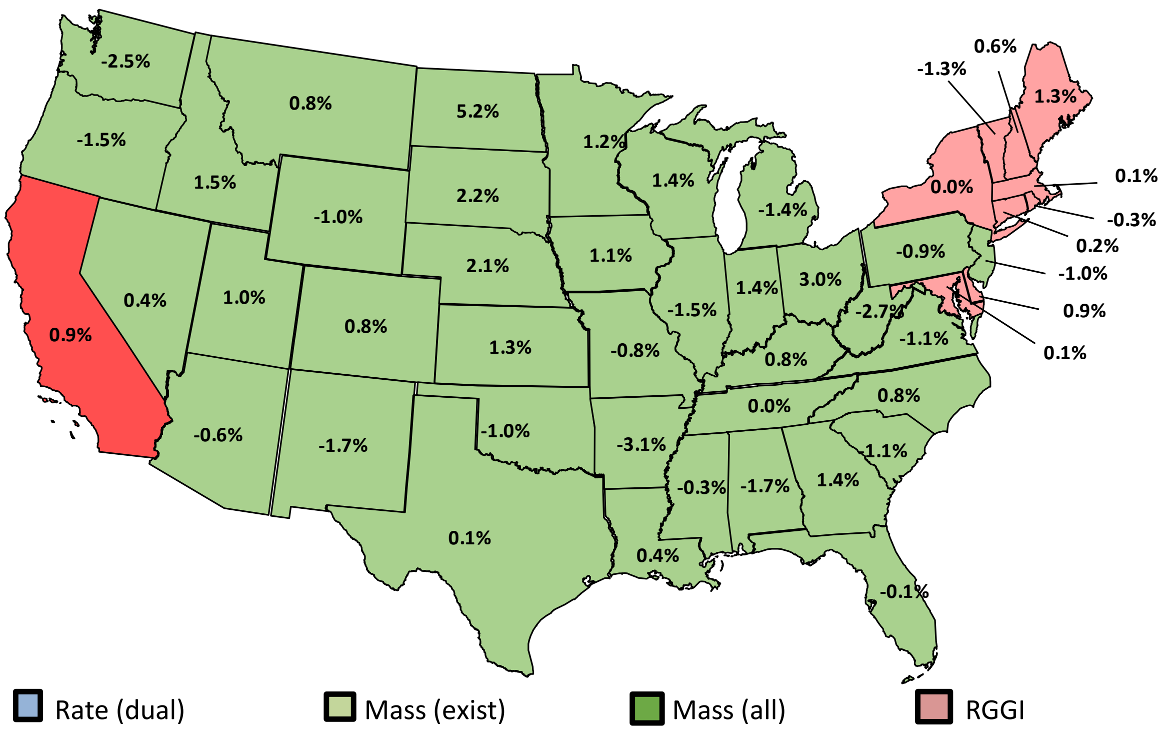
For states that have adopted the mass cap over existing units (the light green states in Figure 16), average U.S. policy costs increase by 0.1% in present value terms through 2040, when the policy has been fully in effect for a decade. However, behind this average cost change is a potential, though small, shifting of costs among states. In tightly interconnected electricity markets, some states bear costs and others, such as North Carolina, South Carolina, and PJM Interconnection states, enjoy benefits. It may be generally appropriate for states with positive costs to view these costs as the worst-case outcome for the interconnected market (given this particular set of assumptions about future trends) and for states with benefits to view such cost changes as the best-case outcome. Actions taken by states or utilities in these markets may even out the distribution of costs across the interconnected group.

[23] If, for example, Pennsylvania has benefits and Ohio has costs, these two policy changes may offset each other for the PJM Interconnection as a whole and not be realized by the individual states in the fashion that the model's cost estimates are determined.

[24] See Appendix A for state-level sensitivity analyses on the national policy results. Even if policy costs for a region or state are close to zero, individual states may be more or less sensitive than their neighbors to variations in gas prices, electricity demand, or renewables costs. Consequently, results will not always move in the "expected" direction.

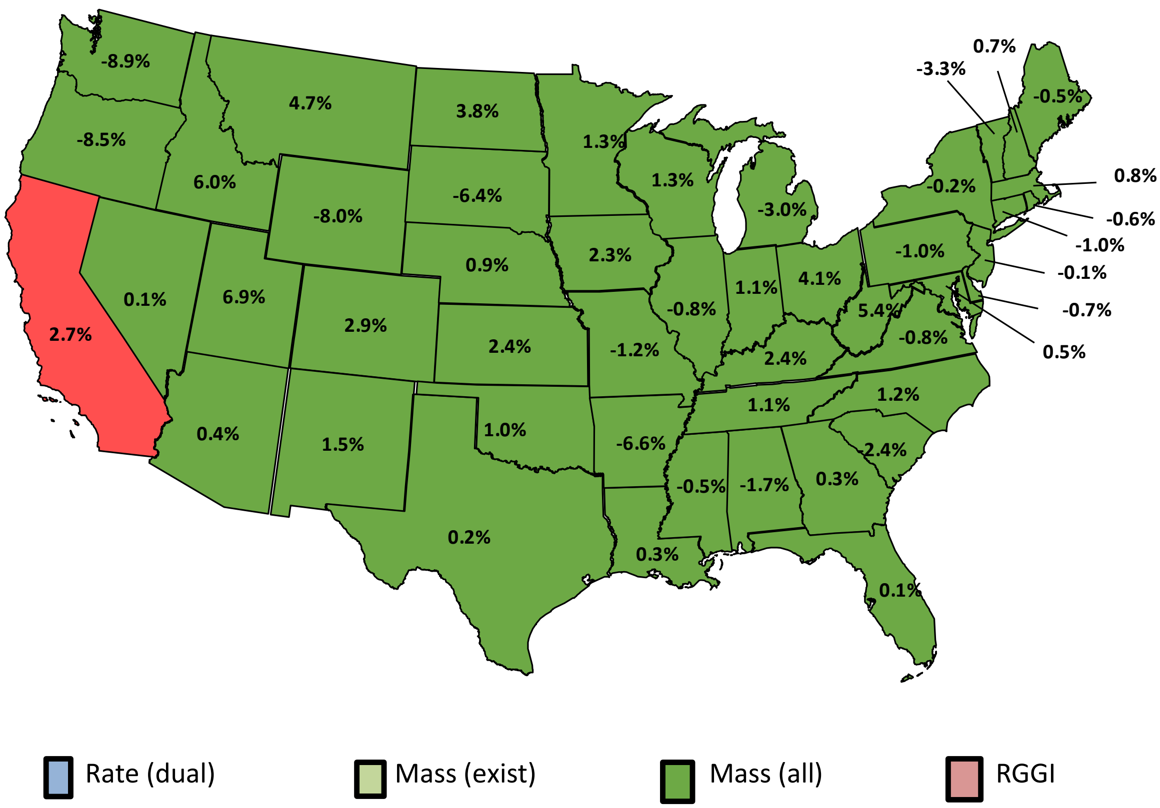
[25] A zero price for allowances in California or RGGI does not preclude states from setting lower bounds on allowance prices to meet AB 32 or RGGI emissions targets.

Figure 24. State policy costs of national mass cap over existing units (change in present value to 2040)



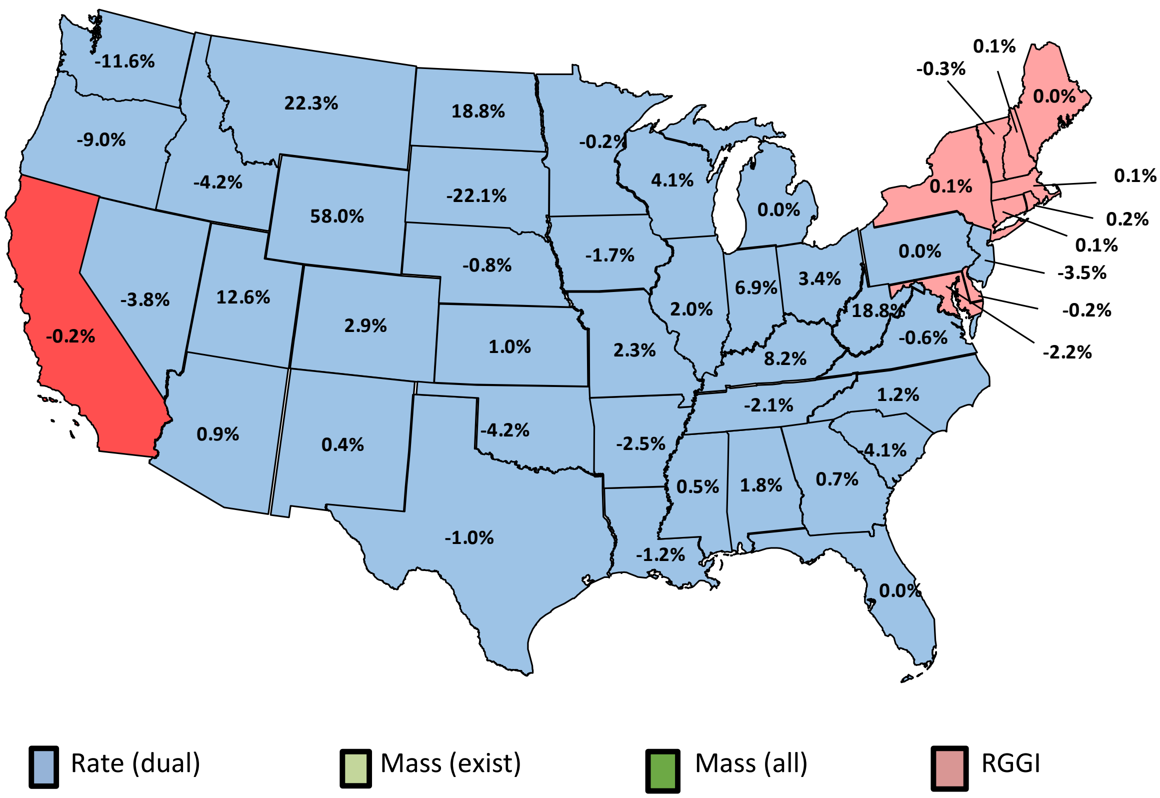
Overall policy costs are 0.5% for a national mass policy with the NSC that includes new NGCC units and in which RGGI joins the trading group with states other than California, which continues to pursue its own policy. Compared with the mass policy over existing units, this policy has higher costs and, through elimination of emissions leakage, significantly higher emissions reductions. In addition, as Figure 25 illustrates, fewer states are likely to reap benefits from the policy. Some states, such as West Virginia, that would have relied on a combination of electricity imports and new NGCC generation under a mass cap covering only existing units will face increased costs because both the imports and the new NGCC generation costs become more expensive. The allowance price in 2030 is now $14.5/ton, contributing to the additional costs associated with gas generation, which tends to be the source that sets wholesale electricity prices (and allowance prices) on the margin. Some states experiencing benefits under the mass cap over existing units may see those benefits grow as their neighbors face higher costs under the mass cap with NSC—a possibility highlighting how potential competition among states could make some states comparatively better off if neighboring states are worse off, depending on how political processes and utilities' actions work to smooth out policy cost differences.

Figure 25. State policy costs of a national mass cap over all units (change in present value to 2040)



Unlike the two mass options in which costs are relatively evenly distributed, a national dual-rate policy under which the ERC price is $15.4/MWh in 2030, is only slightly more expensive at a national level than the mass cap with NSC. However, a rate-based policy would pose significant difficulties for some states, including West Virginia, North Dakota, Wyoming, and Montana (Figure 26). An emissions rate target can be difficult to meet if a state is currently coal dependent, if it tends to export electricity provided by those coal units, or if it has limited access to renewable resources such as wind (declining solar PV costs would help reduce these renewable resource inequities). These types of significant policy-specific difficulties motivate the patchwork policy choices investigated below.

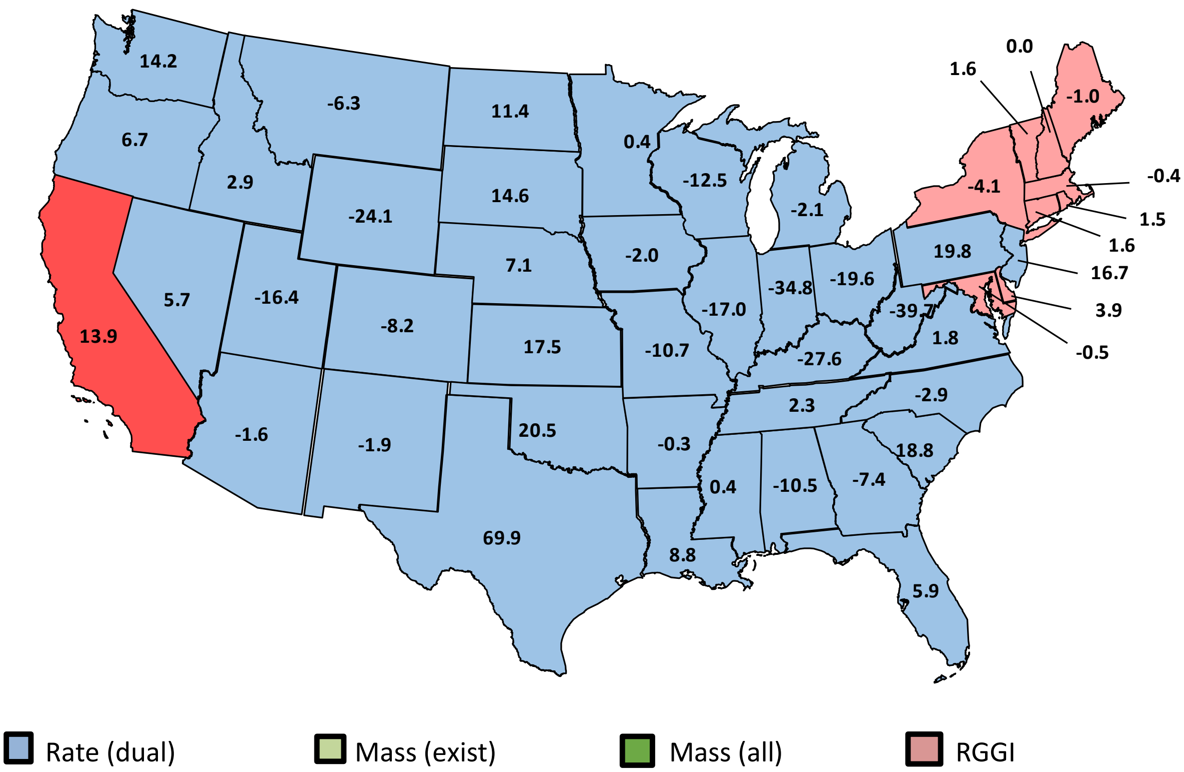
Figure 26. State policy costs of national dual-rate (change in present value to 2040)



Along with costs, an important factor likely to sway a state's choice to pursue or not pursue an emissions rate approach over a mass cap is the state's ability to generate ERCs from under-construction nuclear units or renewables or to generate gas-shift ERCs from existing NGCC units. Figure 27 shows the levels of ERC exports (positive numbers) and imports (negative numbers) for the national dual-rate policy.[26] The modeling shows exports from two of the three states with under-construction nuclear plants (South Carolina and Tennessee), along with significant ERC exports from Texas and middle-of-the-country states (which together are referred to in subsequent tables as the "Plains" states) with access to abundant wind. New Jersey also has excess ERCs and appears likely to choose an emissions rate approach to the Clean Power Plan. The modeling further indicates that those states dependent on ERC imports are also those that would face comparatively high policy costs under a national rate approach.

[26] California has excess allowances under its mass cap with NSC because its emissions cap is non-binding, but no buyers are assumed. In this policy approach, RGGI states trade mass allowances among themselves, leaving no net trade outside RGGI.

Figure 27. State net exports of ERCs (TWh) and mass allowances (MMTCO$_2$) in 2030



ERC Markets in Patchwork Policies

How ERC markets develop will depend not only on states that may find it beneficial to adopt a rate-based approach in order to export ERCs, but also on how many states that would need to purchase ERCs in order to meet emissions goals will choose to join in those ERC markets. A market dominated by selling states will lead to low ERC prices, limiting the value of ERCs to producing states. At the same time, these low prices will encourage states to adopt a rate-based approach to take advantage of the cheap ERCs. At some point in this process, if the market becomes driven by the states demanding ERCs, prices will be high enough to discourage additional states from pursuing rate-based options. The same can be said of potential markets for mass allowances.

Because the potential number of configurations of ERC markets is large, model scenarios examine a range of seller-dominated to buyer-dominated markets, focusing on the eastern half of the nation. Figure 28 shows ERC prices if the states with under-construction nuclear units choose to go with a rate-based approach while other states in the East adopt a mass cap over existing units.[27] Producing ERCs from nuclear plants is a low-cost option and, without a broad market, ERC prices are low at $2.6/MWh in 2030 (prices are zero in most other years). What keeps the price above zero is that Georgia, which imported some ERCs under a national rate scenario (Figure 27), elects to import even more ERCs because local supplies from its new nuclear unit are insufficient to meet its needs. Mass allowance prices over existing units are also quite low at $4.5/ton.[28]

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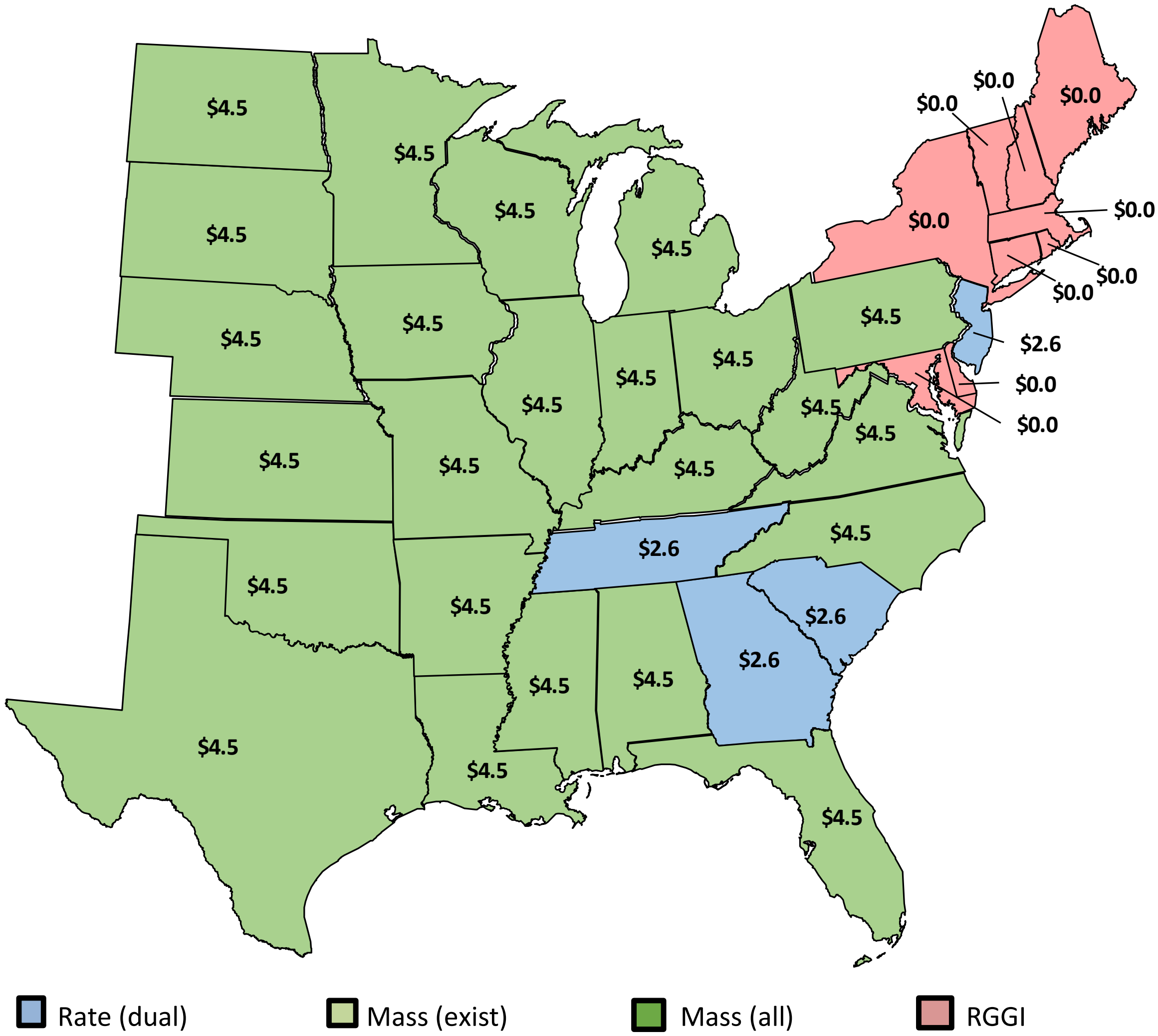
[27] Unless otherwise indicated in the figures, New Jersey is assumed to choose a rate-based approach in almost all patchwork scenarios.

[28] States in the West are assumed to pursue their own mass cap over existing units and to have a higher allowance price at approximately $14/ton, implying that states in the East are selling allowances under a national mass-based approach and that states in the West are buying them (Figure 24).

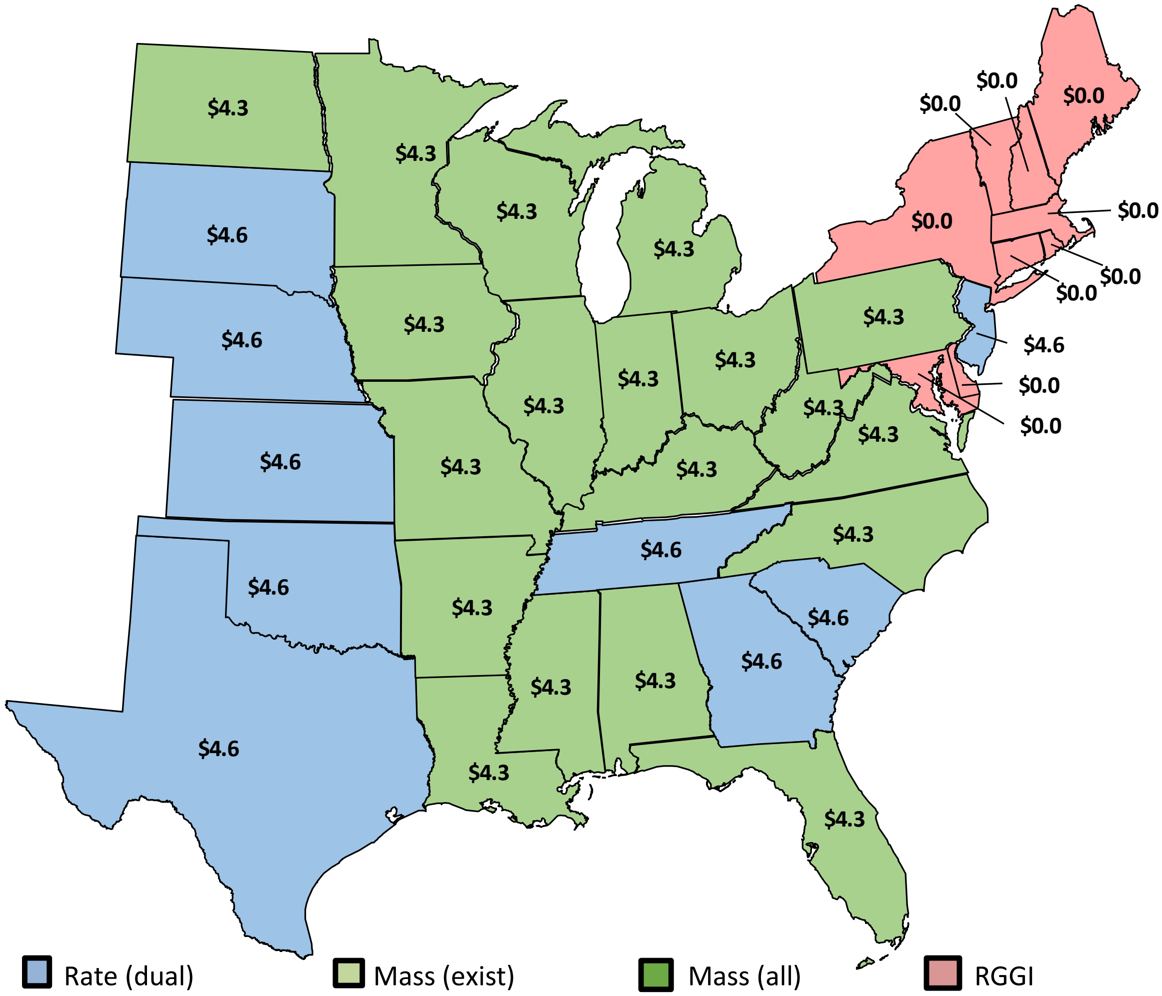
Figure 28. ERC price in nuclear states ($/MWh), mass allowance price in other states ($/ton): 2030



Note: If states in the East adopt a mass cap with NSC, the ERC price would be slightly higher at $3.5/MWh, and the mass allowance price would be $8.8/ton.

If additional states in the Plains, which appeared to be ERC suppliers in a national rate approach, choose to join the ERC market and to adopt a dual-rate policy, ERC prices would actually rise to $4.6/MWh. At this low level, both Texas and Kansas, which would have had excess ERCs at $15/MWh, would now find it more cost-effective to import ERCs instead of adding to their local wind generation. Mass allowance prices would decline slightly because fewer states would be competing for the remaining supply of excess allowances in other states.

Figure 29. ERC price in nuclear and Plains states ($/MWh), mass allowance price in other states ($/ton): 2030



If on the basis of these low ERC prices the rest of the states in the Southeast also chose a rate-based approach to the Clean Power Plan, ERC prices in 2030 would rise to $7.5/MWh (Figure 30), implying that these other states are importing a fair number of ERCs. A similar increase would occur if the East Central states, rather than the Southeast states, chose a rate-based approach on the basis of low ERC prices in plains states. If they are the only new states to enter (Figure 31), ERC prices rise to $6.9/MWh, or slightly less than occurred in the Southeast states. If both regions choose to join at once, the ERC price in 2030 is $10.8/MWh. Finally, if the entire rest of the east goes with dual-rate (while the west stays with mass over existing units), the ERC price rises to $14.9/MWh (see Figure 33) which is close the national average of $15.4/MWh from a coordinated national rate policy.

Figure 30. ERC price in nuclear, plains, and southeast states ($/MWh), mass allowance price in other states ($/ton): 2030

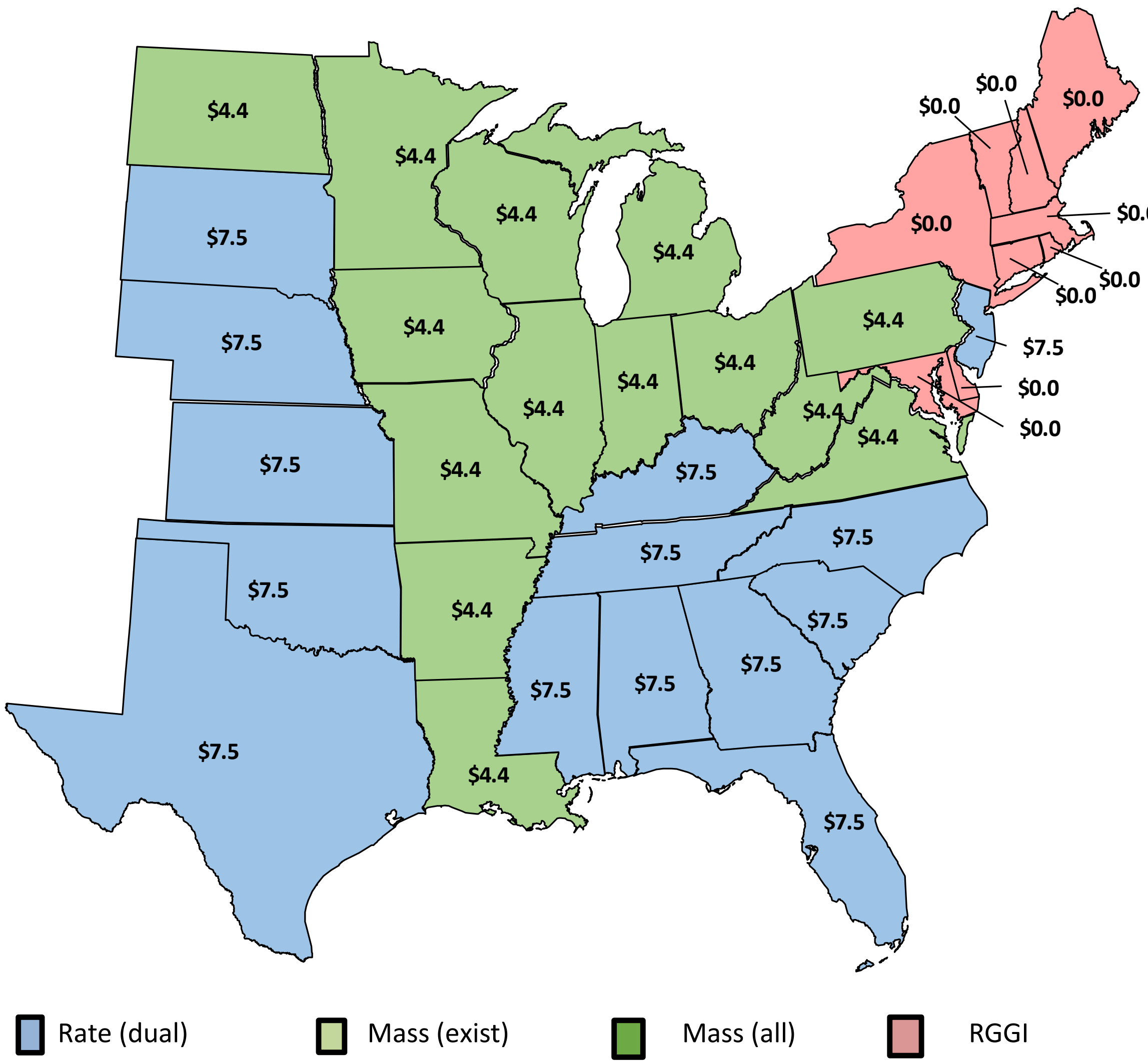


Figure 31. ERC price in nuclear, plains and East Central states ($/MWh), mass allowance price in other states ($/ton): 2030

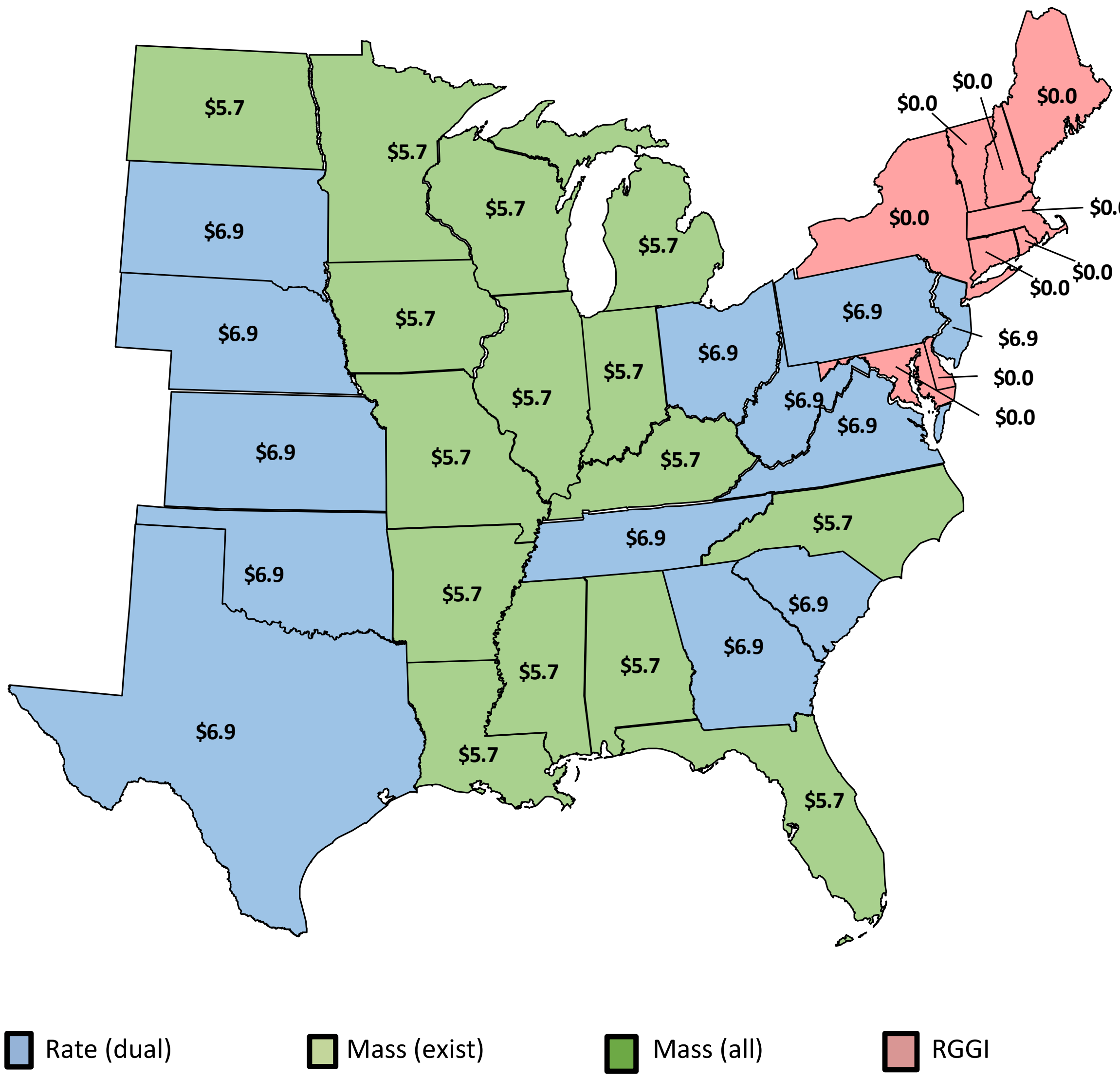


Figure 32. ERC price in nuclear, plains, Southeast and East Central states ($/MWh), mass allowance price in other states ($/ton): 2030

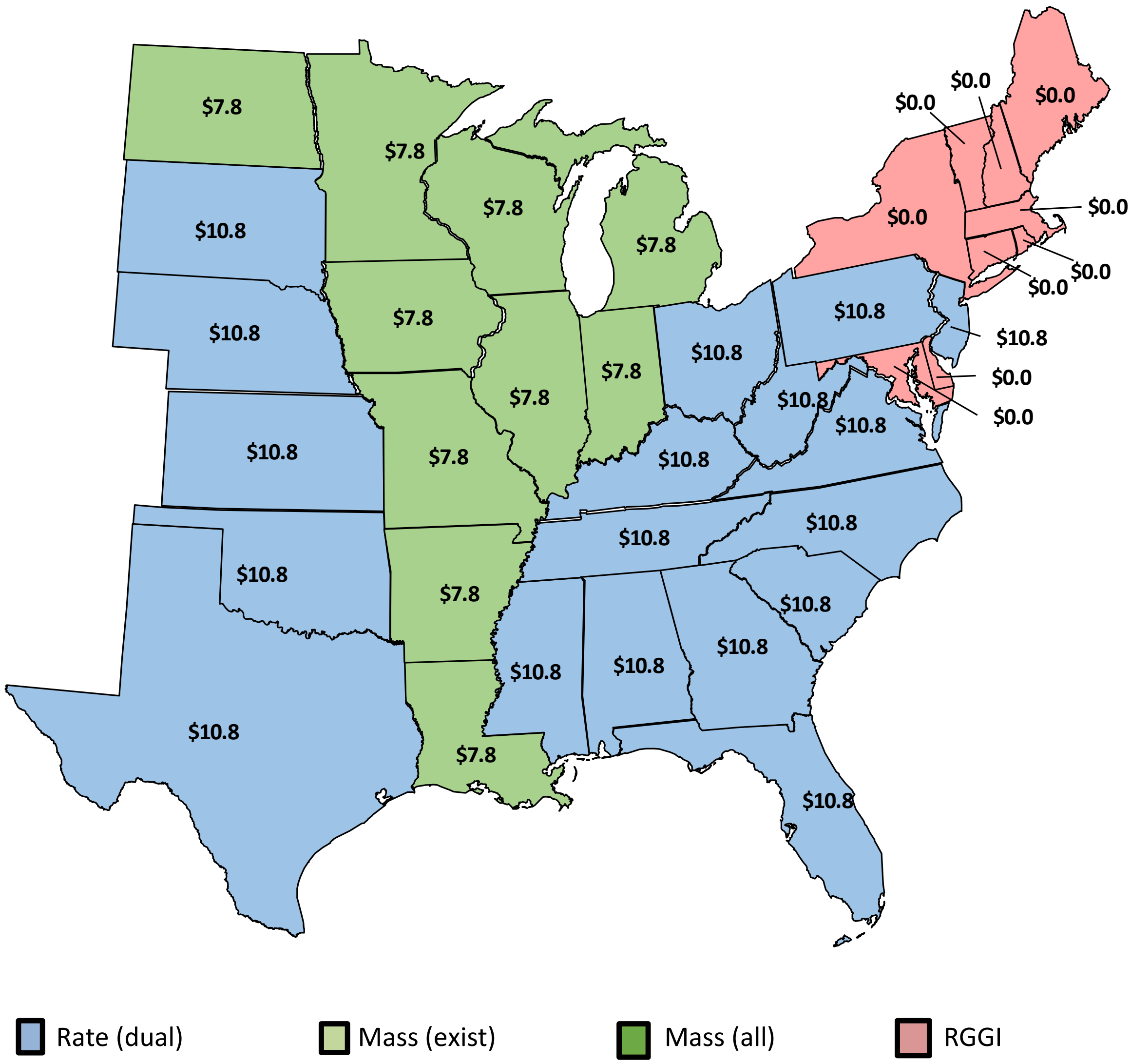
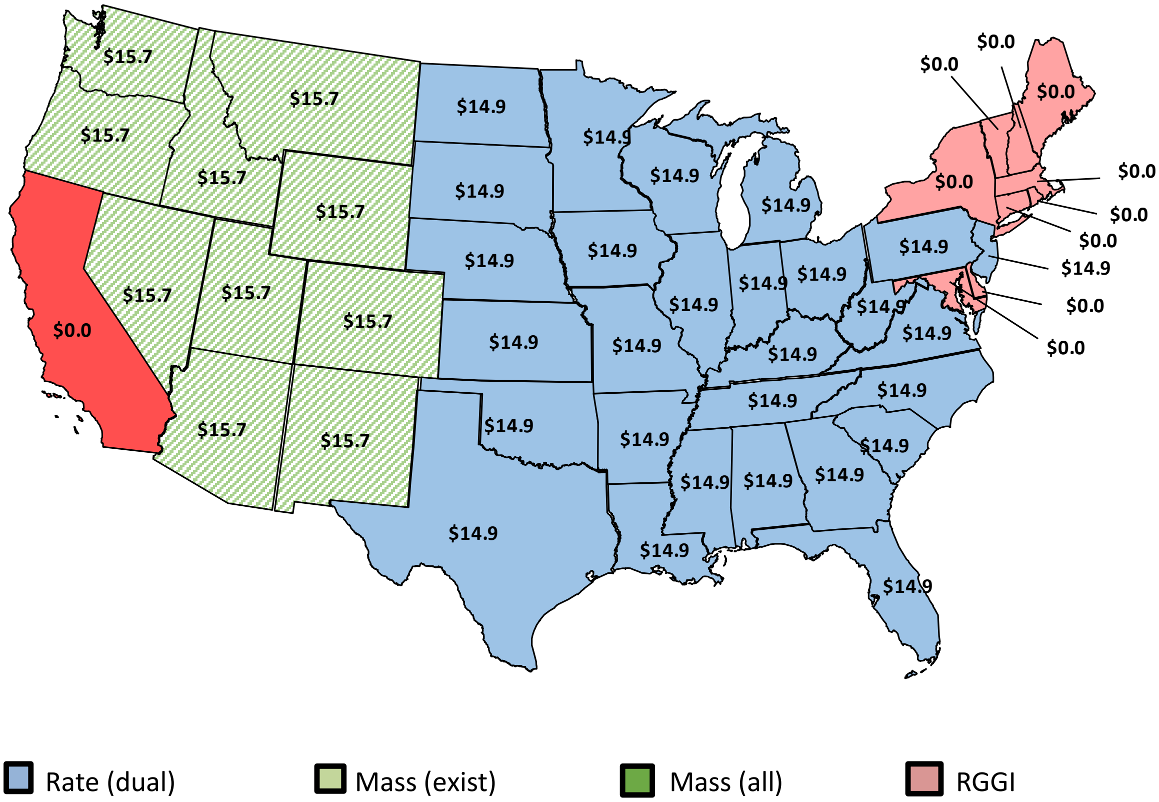
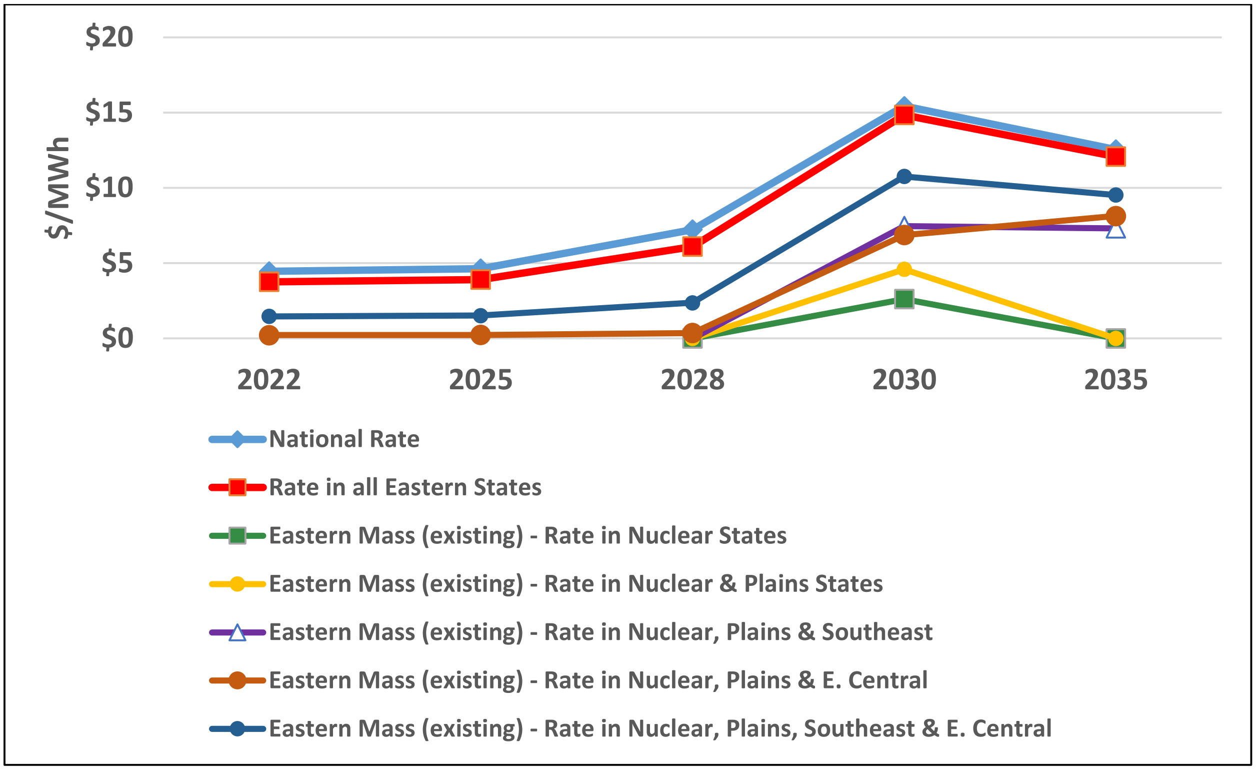


Figure 33. ERC price in the East ($/MWh), mass allowance price in the West ($/ton): 2030



Even though, for many potential groupings of ERC markets, the prices shown above are relatively low, these prices, which are for the year 2030, usually represent the high point of their values (Figure 34). One implication of this finding is that, depending on the breadth of ERC markets, a dual-rate approach may not provide much of a subsidy to renewables. ERC prices of $7–$8/MWh result in an additional 30 TWh of wind generation in the South Central region in 2030. ERC prices need to be in the $10–$15/MWh range for additional wind generation in that region to reach 55 TWh and for any additional wind (20 TWh by 2030) to be constructed in the North Central states.

Figure 34. ERC prices over market breadth and time ($/MWh)



State-Level Impacts of Patchwork Rate-Based Policies

Figures 35–40 examine the state-level policy costs of the patchwork options, moving from a scenario in which most states adopt a mass cap over existing units (Figure 35) to a scenario in which most states become part of a rate-based trading scheme (Figure 40). (Results for a similar set of runs using the mass cap over all units are shown in Table 5 below, and sensitivity results of the standard set of model assumptions are presented in Appendix B). It is assumed, but not shown in figures 35–39, that western states adopt a mass cap over existing units and form a regional trading group if some eastern states form their own regional trading group for a mass cap over existing units. Similarly, if the eastern states pursue a mass cap over all units, the western states also pursue a mass cap over all units for consistency.

Patchwork approaches raise the costs of the CPP policy to the nation as a whole, but they may provide some benefits to individual states.[29] A comparison of Figure 35 with Figure 24, in which all states but California and the RGGI states adopt a mass cap over existing units, shows that the nuclear states and New Jersey are better off going with a rate-based approach even though the market for their ERCs is limited to four states. The one exception is Tennessee, which is very slightly worse off. These results must be viewed with caution because the mass allowance price for the eastern United States is also lower in this patchwork scenario than under the national approach, the results of which are depicted in Figure 24.[30] Many other states are also mildly better off in this approach, although hard-and-fast conclusions should not be drawn for cost changes of these small magnitudes.

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[29] The policy cost for the national mass cap over existing units is +0.08% through 2040 for the country as a whole. Splitting the country into eastern and western trading groups raises the cost to +0.11%, which is a large increase in percentage terms but a low cost in absolute terms. The mass cap over all units has a cost of +0.54% for a national approach and +0.60% for an East/West approach.

[30] ,Figure 24 does not offer an exact comparison to this East/West approach.

Figure 35. Patchwork policy costs under a rate-based approach in nuclear states (ΔPV to 2040)

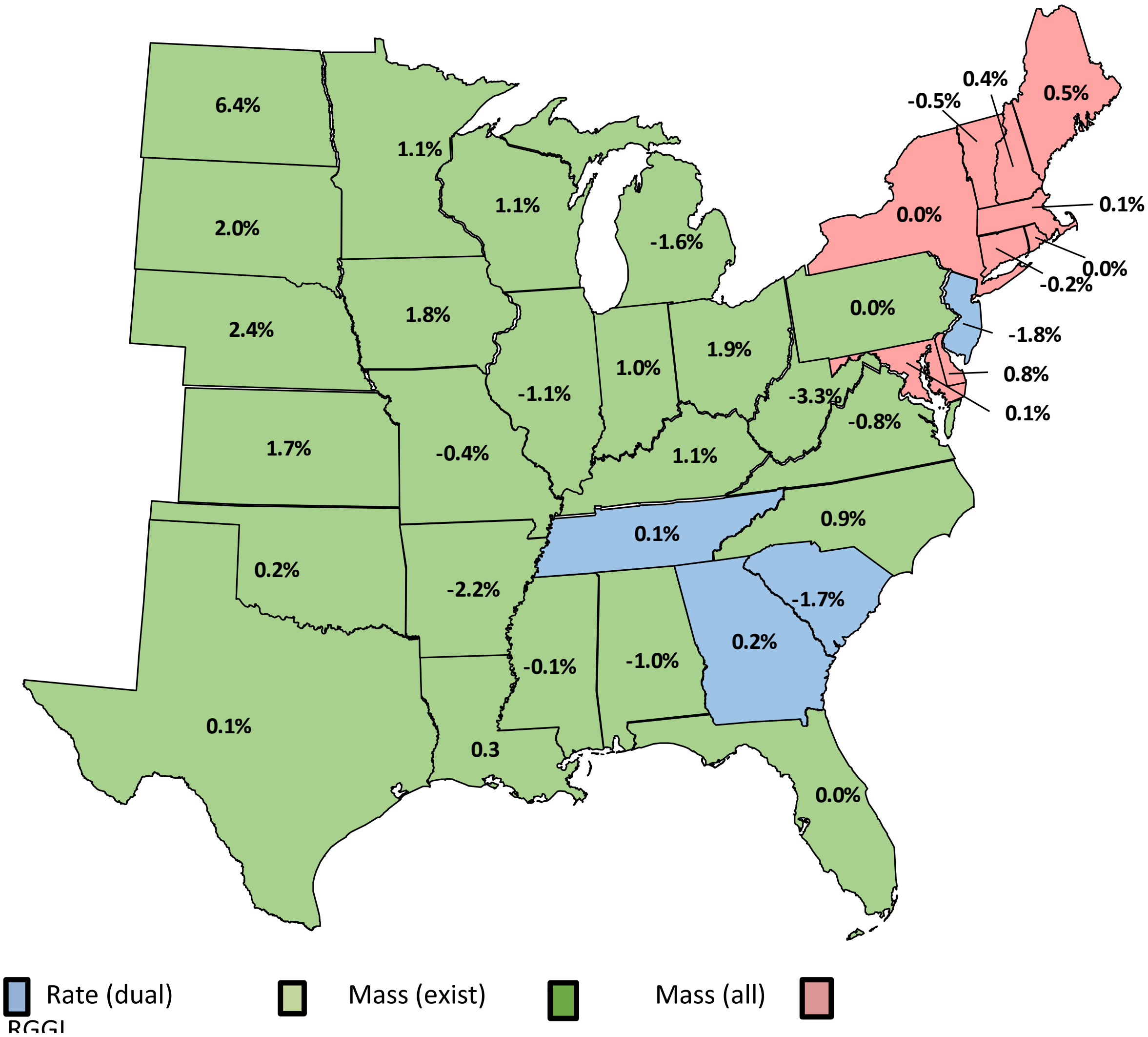


Table 3 facilitates interpretation of the estimated cost impacts of the various patchwork scenarios. It contains the same type of information as Figure 27, which depicts what occurs in 2030, when states in the East with a dual-rate policy (in blue) have data on net exports of ERCs (in TWh) and states with the mass cap over existing units (in light green) have data on net exports of mass allowances (in $MMTCO_2$). Net exports of ERCs, or allowances, balance across the rate-based trading regions (in blue) and mass-based trading regions (in green), unless the value of ERCs or allowances is zero, in which case the cumulative quantities may be positive, indicating an excess supply, as is the case for the RGGI states (in light red).

Figure 35 corresponds to the third column of numbers in Table 3 ("Mass (exist) – rate in nuclear states"). The data show that, for this patchwork approach, New Jersey and South Carolina have positive net exports of ERCs, whereas Georgia and Tennessee have negative net exports (or imports) of those same ERCs. It appears that one reason that Tennessee is slightly worse off under this patchwork rate policy than it was under the national mass policy over existing units is that it is importing ERCs from the other rate-scheme participants. The same effect does not hold for Georgia, which is better off importing most of the cheap ERCs available in this trading block than attempting to meet policy goals through local actions.

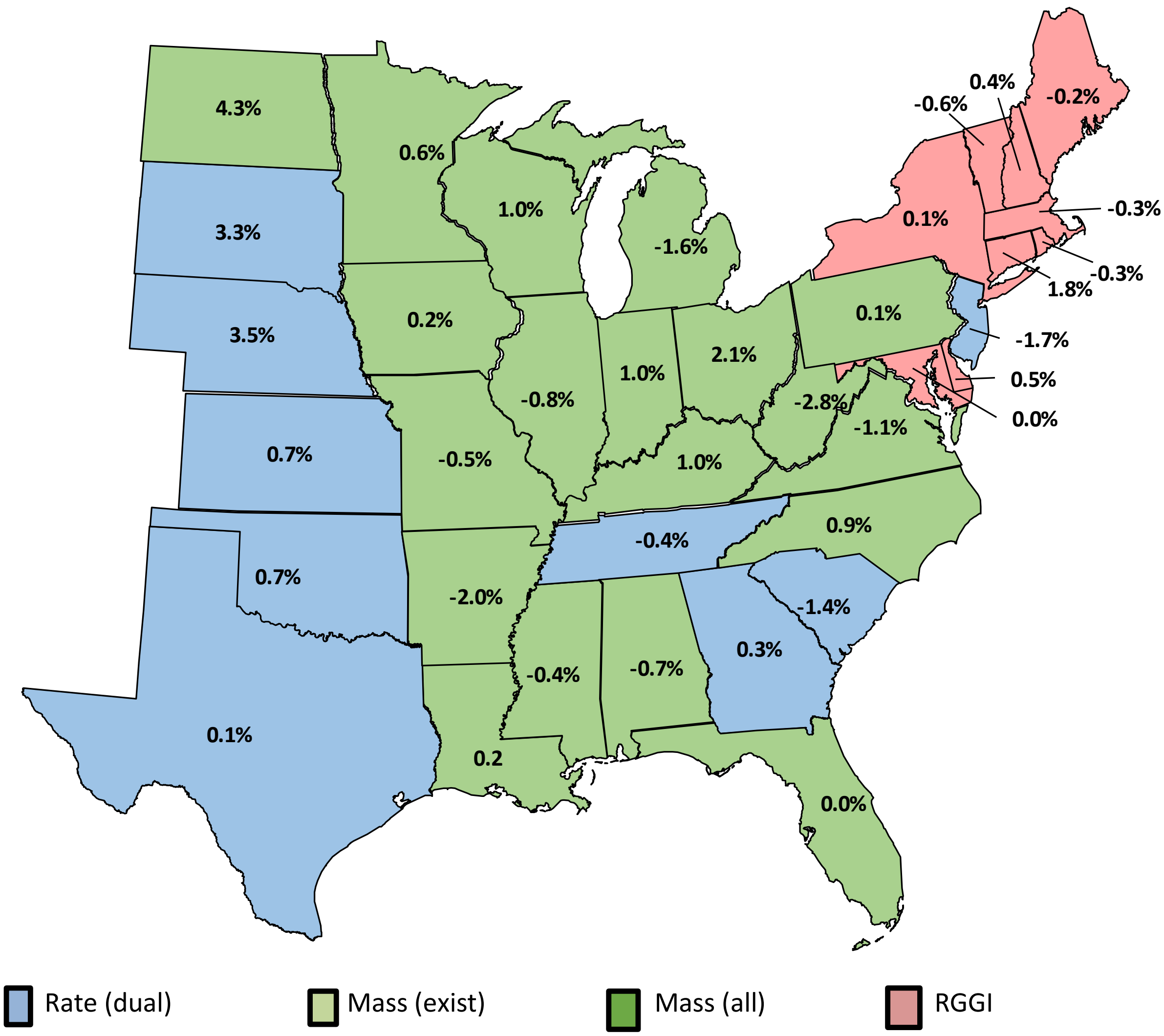
Table 3. Patchwork policies: state net exports of ERCs (TWh) and mass allowances ($MMTCO_2$) in 2030

Region/state	Rate (dual)	Mass (exist)	Mass (exist) -- rate in nuclear states	Mass (exist) -- rate in nuclear & plains	Mass (exist) -- rate in nuclear, plains & Southeast	Mass (exist) -- rate in nuclear, plains & East Central	Mass (exist) -- rate in nuclear, plains, Southeast & East Central	4-region mass (exist)	4-region mass (exist) -- rate in nuclear & plains
Southeast									
AL	-13.0	0.8	3.7	3.9	-13.9	4.1	-13.9	5.1	3.5
FL	6.1	18.1	16.3	19.9	-2.6	17.9	-1.1	20.8	12.8
GA	-7.6	-22.5	-15.6	-13.6	-11.1	-11.1	-11.1	-23.2	0.0
KY	-28.4	-18.4	-26.5	-20.1	-34.4	-19.0	-32.9	-14.8	-25.6
MS	0.4	9.2	8.3	9.5	-0.5	12.8	-0.5	8.5	5.3
NC	-3.1	1.5	5.9	5.5	-6.0	8.3	-4.1	3.8	4.0
SC	18.6	4.4	6.2	6.8	14.4	7.7	15.7	6.8	0.0
TN	2.3	-7.1	-1.7	-1.1	0.2	0.2	0.2	-7.1	0.0
E. Central									
NJ	16.2	6.5	11.1	11.9	12.7	13.1	14.4	5.8	-208.6
OH	-18.5	-22.8	-25.7	-24.0	-16.3	-22.9	-19.9	-34.6	-31.9
PA	19.9	74.4	72.5	71.1	70.1	16.6	17.6	63.3	64.5
VA	0.8	2.6	3.5	4.0	3.7	1.2	0.7	-0.1	2.3
WV	-39.8	-33.7	-34.0	-32.9	-32.2	-41.1	-40.8	-34.3	-34.9
RGGI									
CT	1.6	1.0	1.1	0.9	1.2	1.3	1.4	1.1	1.3
DE	3.9	4.1	4.0	4.0	4.0	4.0	4.0	4.1	4.1
ME	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0
MA	-0.4	-0.5	-0.3	0.2	-0.1	-0.3	-0.3	-0.3	-0.2
MD	-0.2	6.2	6.4	6.2	4.4	4.6	4.0	6.4	6.7
NH	1.6	1.4	1.5	1.5	1.6	1.6	1.6	1.4	1.5
NY	-4.2	-4.3	-4.2	-4.2	-4.2	-4.3	-4.2	-4.2	-4.2
RI	1.5	1.4	1.4	1.3	1.5	1.5	1.5	1.4	1.4
N. Central									
AR	-0.3	8.9	8.9	9.1	9.1	9.2	10.7	9.6	9.2
IL	-17.7	-12.2	-13.0	-12.3	-12.0	-12.2	-9.6	-6.3	-8.4
IN	-35.6	-19.1	-19.7	-17.5	-17.9	-14.5	-11.4	-7.2	-7.0
IA	-5.1	-11.2	-11.8	-11.5	-11.5	-10.6	-10.3	-10.0	-10.0
LA	8.7	3.2	3.0	3.9	11.4	6.4	16.3	12.4	15.4
MI	-2.1	7.5	6.2	6.0	7.8	9.5	11.1	11.2	11.4
MO	-11.6	14.9	14.3	14.6	15.3	15.0	16.3	16.3	15.9
MN	-1.7	-7.4	-7.5	-7.5	-7.4	-6.5	-5.3	-6.2	-6.5
ND	8.4	-12.3	-12.6	-12.6	-12.1	-10.8	-10.8	-11.6	-12.1
SD	14.6	-0.3	-0.3	7.6	8.5	8.0	11.1	0.0	0.0
WI	-12.6	-9.5	-9.5	-9.2	-8.0	-9.6	-7.0	-8.1	-7.9
S. Central									
KS	15.9	-14.5	-14.5	-10.3	7.3	7.1	9.5	-16.1	0.0
NE	6.5	-1.5	-1.6	1.3	4.6	4.6	5.1	-1.6	0.0
OK	18.9	16.1	16.1	7.0	7.7	7.3	11.5	14.8	0.0
TX	59.7	24.5	18.0	-9.7	13.0	9.1	38.3	3.0	0.0

Adding the plains states to the rate-based policy approach (Figure 36) has somewhat mixed impacts on costs for states joining the rate-based trading group, in part because ERC prices remain too low to incentivize additional wind generation in the plains, as was discussed above. Consequently, states such as Kansas that choose to import cheap ERCs at these valuations (see the fourth column in Table 3) are better off than when they were outside of the rate-based trading group (as depicted in Figure 35). South Dakota, Nebraska, and Oklahoma, which are the states exporting ERCs in this scheme, are, as the result of the low ERC values, worse off than when they were outside of the rate-based trading group.

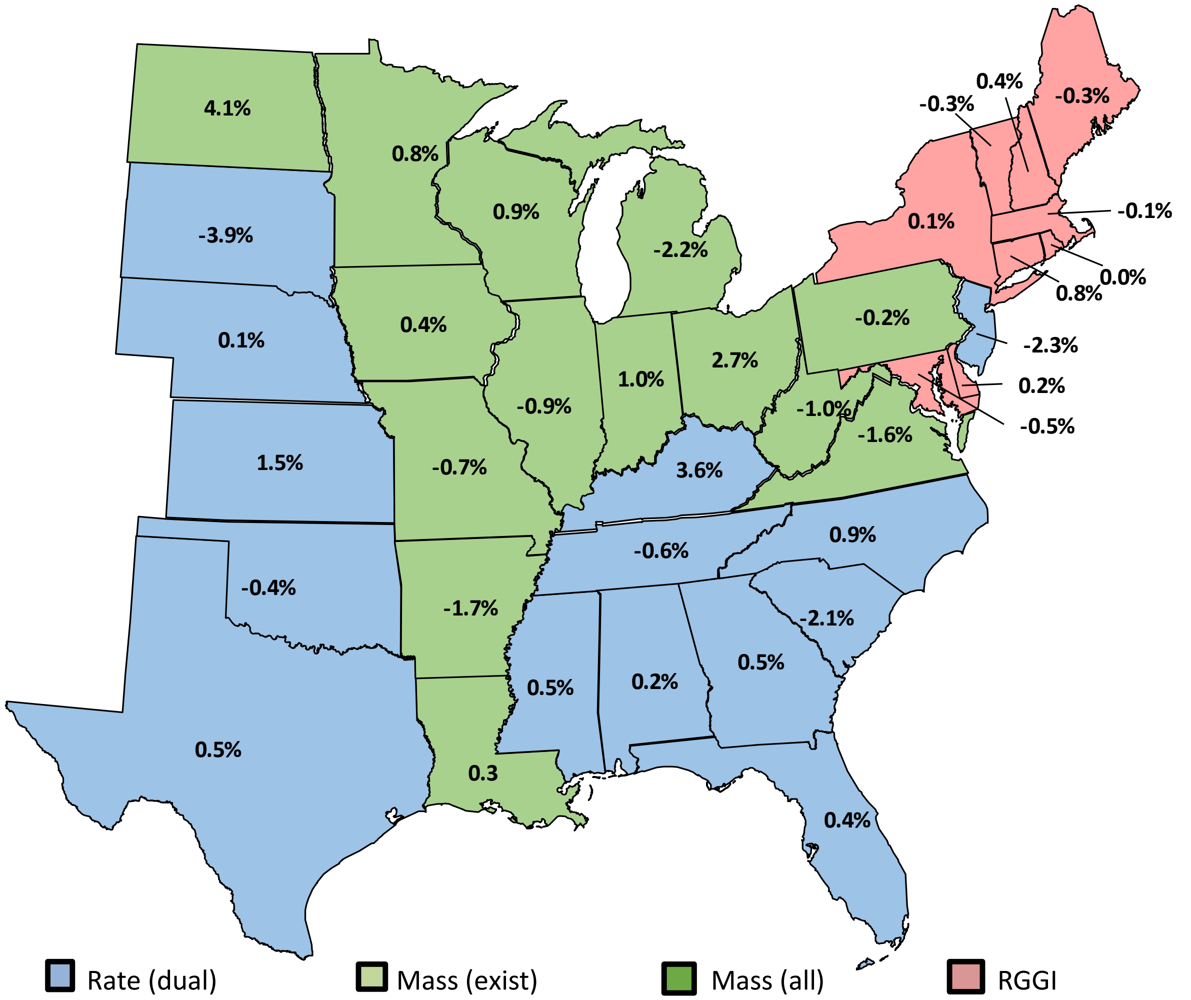
The comparison of figures 35 and 36 also begin to highlight a fairly general finding that states become better off when the policy choices of their neighbors make those neighbors worse off. Figure 36 shows that North Dakota, Minnesota, and Iowa are better off when the plains states of South Dakota and Nebraska experience additional costs from joining the rate-based trading group.

Figure 36. Patchwork policy costs with rate-based trading in nuclear and plains states (ΔPV to 2040)



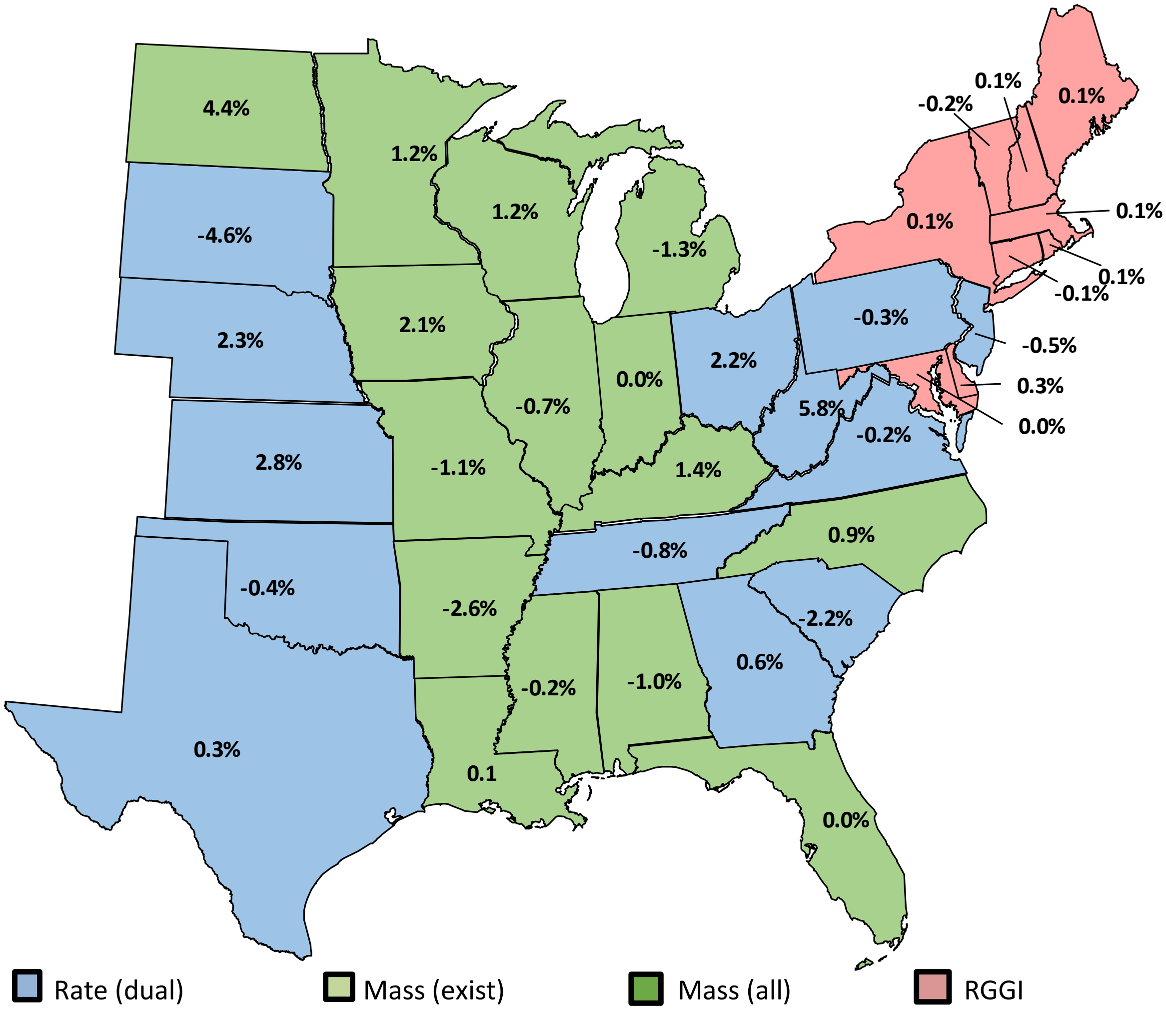
Bringing the Southeast states into the rate-based patchwork policy (Figure 37) increases demand for ERCs to the point that ERC prices rise to $7.5/MWh, which encourages the plains states to export ERCs to many of the Southeast states (fifth column in Table 3). ERC exporters outside of the plains are all better off with the higher ERC values (South Carolina, New Jersey, and Tennessee). The cost picture is somewhat more mixed for the plains states: some, such as South Dakota, Nebraska, and Oklahoma, have lower costs with the broader ERC markets. ERC values are not yet high enough to benefit some of the plains states such as Texas and Kansas. It is unclear, however, if many of the non-nuclear Southeast states would have an incentive to join this rate-based trading group. Due to its existing generation structure, Kentucky is particularly disadvantaged under a rate-based scheme compared to a mass-based policy.

Figure 37. Patchwork policy costs with rate-based trading in nuclear, plains, and Southeast states (ΔPV to 2040)



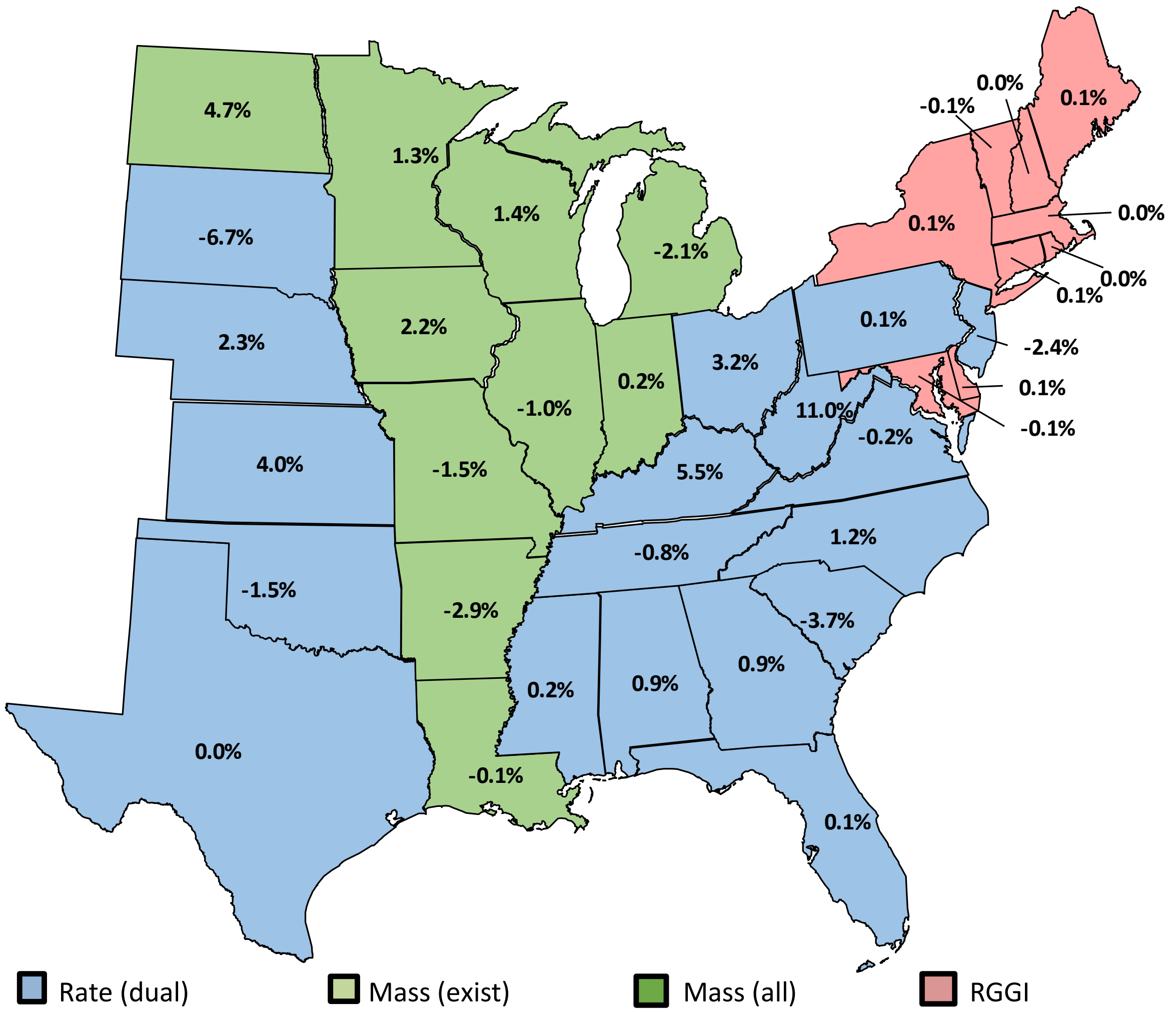
Similar conditions would occur if the East Central states were to join with the nuclear and plains states in a rate-based policy. Some states, and especially West Virginia, are particularly disadvantaged under a rate-based policy because of their existing generation mix. South Carolina and some of the plains states benefit from the expanded ERC markets and higher ERC valuations ($6.9/MWh) in this patchwork option, but some states in the East Central region see increases in costs under this option. Again, as a comparison of figures 38 and 36 shows, surrounding states such as Michigan and Indiana can be better off when costs in the East Central region rise.

Figure 38. Patchwork policy costs with rate-based trading in nuclear, plains, and East Central states (ΔPV to 2040)



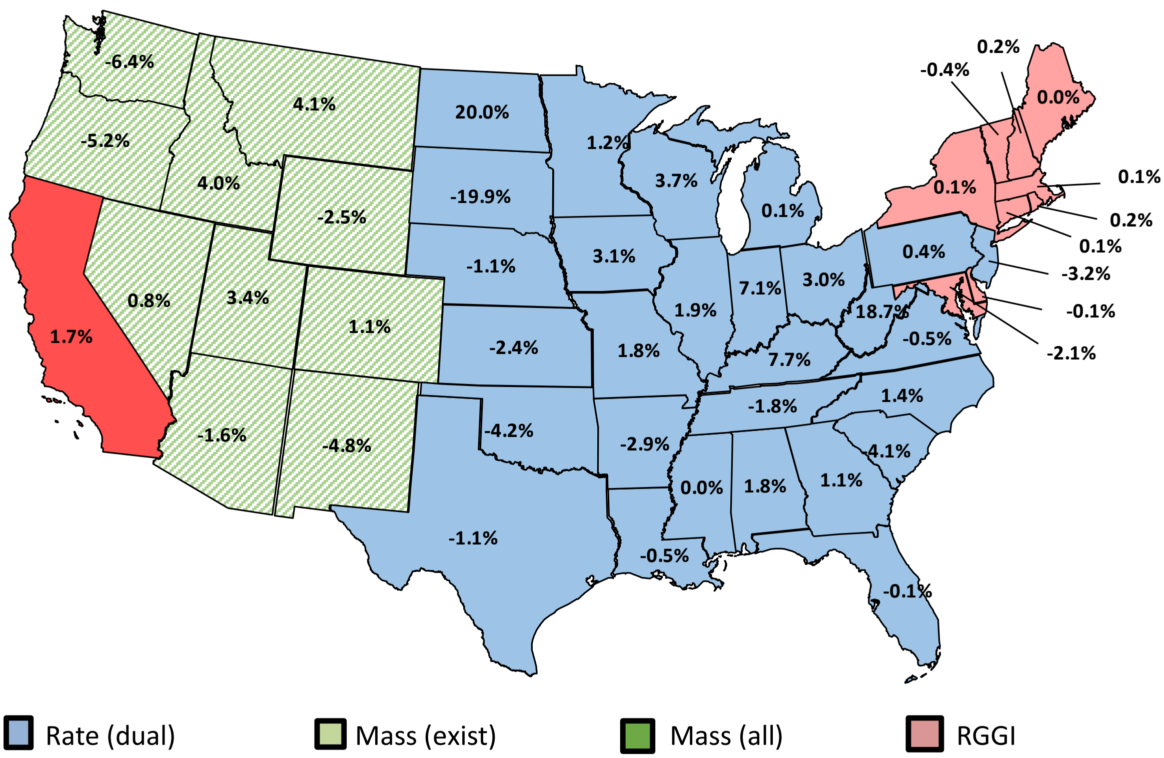
If both the Southeast and East Central regions join the rate-based trading group (Figure 39), demand for ERCs drives ERC prices to $10.8/MWh—still short of the valuation in a national rate-based policy but increased to the point that many ERC exporters experience additional benefits from the policy. In this patchwork approach, two states heavily reliant on their current fleet of coal units (Kentucky and West Virginia) drive much of the demand market for ERCs. Thus, neither one would be likely to join a rate-based trading group. The cost results also show how many of the North Central states benefit as generation costs rise in their neighboring states.

Figure 39. Patchwork policy costs with rate-based trading in nuclear, plains, Southeast, and East Central states (ΔPV to 2040)



Finally, if all of the non-RGGI eastern states were to choose a rate-based policy, large benefits could flow to states exporting ERCs at $14.9/MWh (in 2030), and large costs could accrue to ERC-importing states (Figure 40). Compared to a coordinated mass-based policy in which eastern states participate, this policy approach would lead to a highly uneven distribution of cost impacts across states (see tables 4 and 5).

Figure 40. Patchwork policy costs with rate-based trading in the East (ΔPV to 2040)



State-Level Impacts of Patchwork Mass-Based Policies

Figures 41 and 42 depict what might happen if states in the East adopt a mass-based cap over existing units, but choose to form local allowance trading groups similar to RGGI, rather than to pursue a more broadly coordinated system. Figure 41 shows that the East Central region has relatively little trouble meeting the mass cap on existing units with an allowance price in 2030 of $2.7/ton. Conversely, the Southeast has the hardest time of the regions at the margin with a price of $7.1/ton. These regional variations in allowance prices indicate that additional, untapped benefits from trade are available to the East as a whole, although the distribution of benefits may depend on a wide range of factors such as generation mix, fuel prices, electricity flows, and the method by which states and utilities choose to divide costs.

Figure 41. Allowance prices with a mass-based cap over existing units in the East ($/ton): 2030

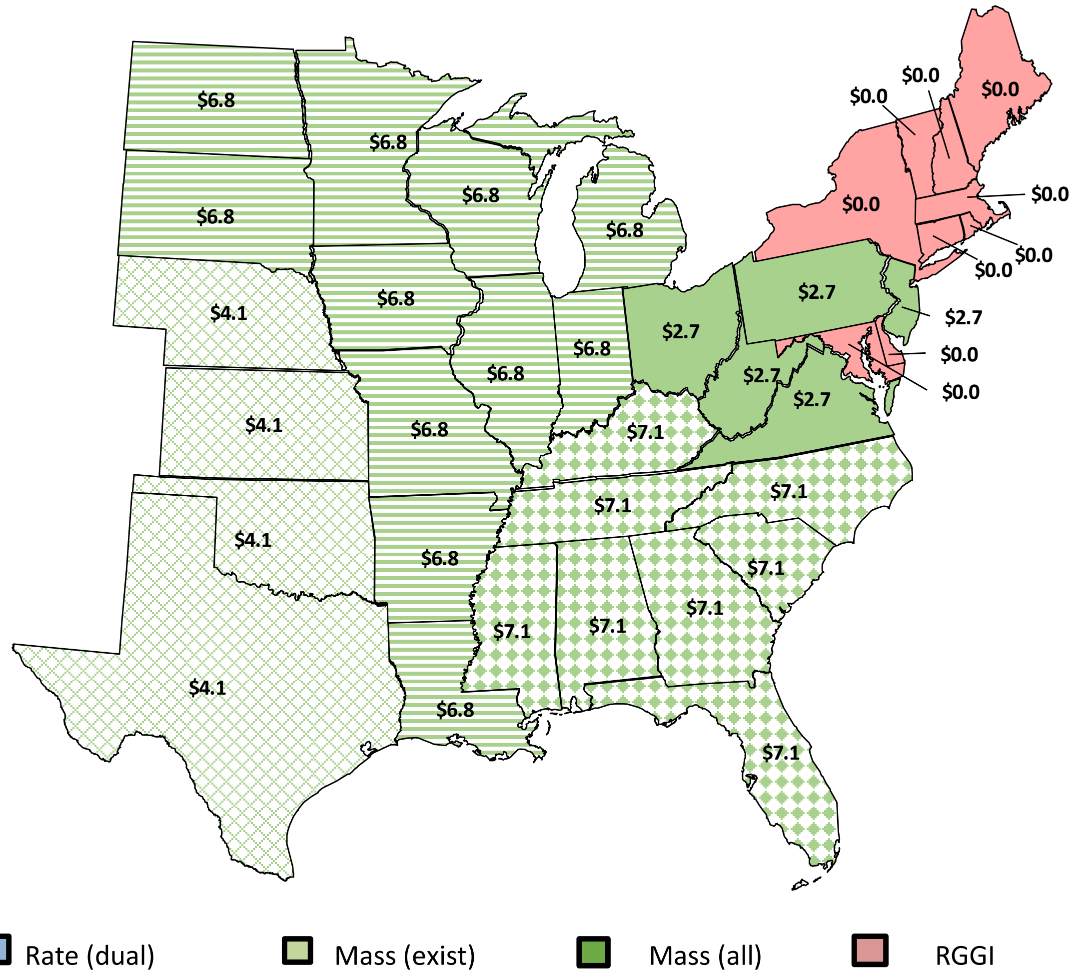


Figure 42 and Table 4 show that, on average, the East Central region may have slightly lower policy costs under a mass-based policy than a rate-based policy, given the region's relatively low allowance price. But this finding does not hold for New Jersey, which can experience benefits under a rate-based policy. In the Southeast, states such as Kentucky and Georgia that import allowances (the eighth column of Table 4) can face increased policy costs because allowance prices rise as the trading area shrinks. Given those two states' increased costs, the Southeast as a whole is slightly worse off under a mass-based policy than a rate-based policy, but some states do benefit if they export allowances.

Figure 42. Patchwork policy costs with a mass-based cap over existing units in the East (ΔPV to 2040)

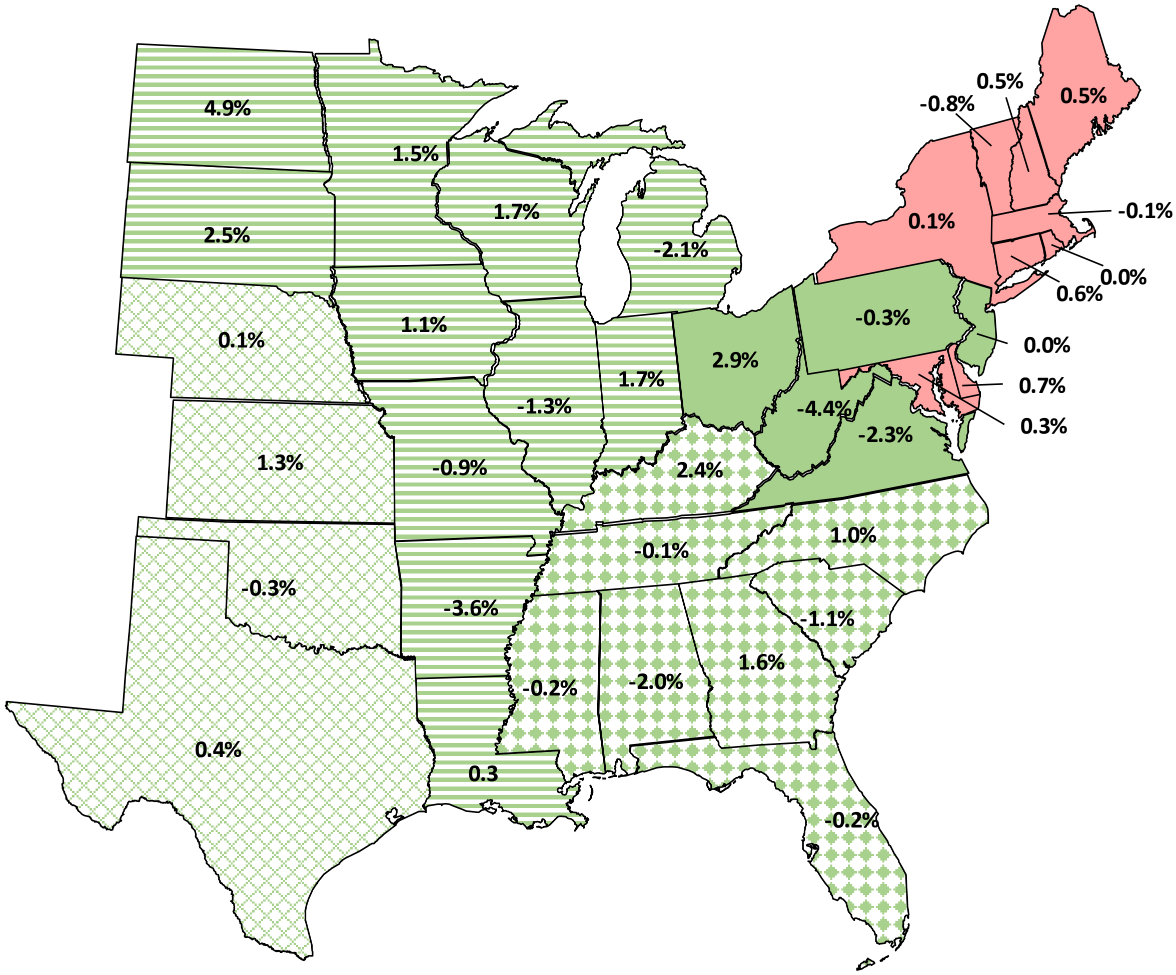
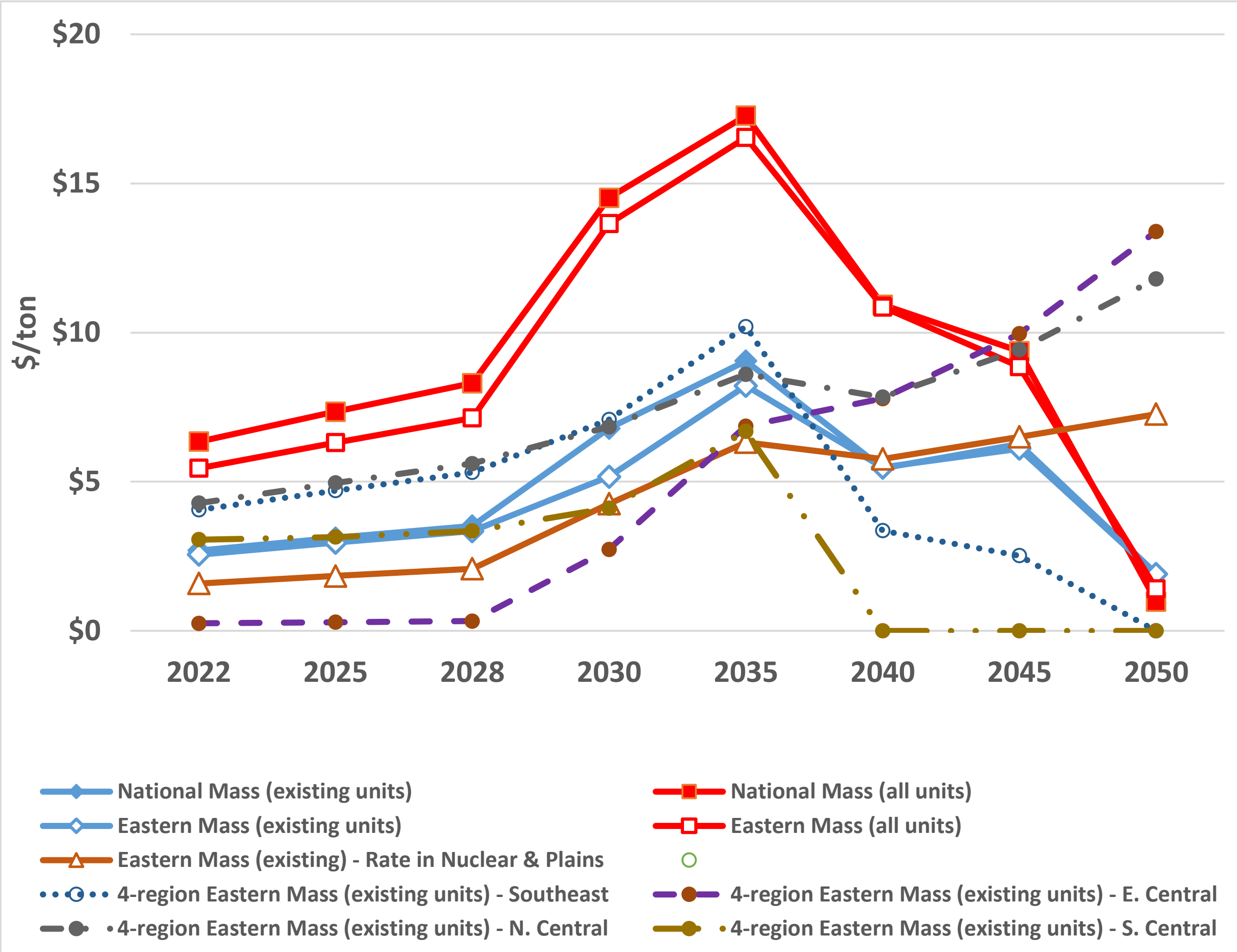


Figure 43 highlights how mass-based allowance prices evolve for the above-described range of patchwork scenarios. Like rate-based ERC prices (Figure 34), mass-based allowance prices tend to be very low in all years, aside from the full implementation year of the policy in 2030. As a group, eastern states face allowance prices that are slightly lower than those under a coordinated, national mass-based policy, whether it covers existing units or all units. As expected, the mass cap with NSC has allowance prices above those of the existing units option. Segmented mass-based trading among eastern states can move allowance prices up or down, depending on the characteristics of the region in question, whereas dropping some states such as the nuclear and plains states from the mass-based policy lowers allowance prices (at least initially).

Figure 43. Mass allowance prices over market breadth and time ($/ton)



The tables below use color coding to indicate the highest cost (in red) and lowest cost (in green) outcomes for each region or state in the eastern United States. Table 4 compares an eastern region (Eastern Interconnection + ERCOT) dual-rate policy to the range of patchwork scenarios related to the mass cap over existing units and rate-based options shown above. Table 5 extends these results, comparing the mass-based policy over all units to the range of possible patchwork rate options.

The results for an eastern region, dual-rate approach are included in tables 4 and 5. In Table 4, the color coding makes that approach appear a costlier option than the others, but the emissions outcomes for the rate-based approach and the mass cap over existing units are not comparable. A more appropriate emissions reduction comparison is shown in Table 5, which presents results for the rate-based approach and those for the patchwork scenarios for a mass cap over all units.

In general, costs for the CPP scenarios are the lowest when the eastern United States pursues a consistent mass-based approach, whether over existing units or all units. On average, costs then rise as more and more states join a rate-based approach, until the point at which all states in the East are covered by a dual-rate policy. But these findings do not necessarily hold true for individual states within the East.

Table 4. Patchwork policy costs across scenarios with a mass cap over existing units (ΔPV to 2040)

Region/state	Rate (dual)	Mass (exist)	Mass (exist) -- rate in nuclear states	Mass (exist) -- rate in nuclear & plains	Mass (exist) -- rate in nuclear, plains & Southeast	Mass (exist) -- rate in nuclear, plains & East Central	Mass (exist) -- rate in nuclear, plains, Southeast & East Central	4-region mass (exist)	4-region mass (exist) -- rate in nuclear & plains
Southeast	**0.7%**	**0.1%**	**0.0%**	**0.0%**	**0.5%**	**0.0%**	**0.5%**	**0.2%**	**0.0%**
AL	1.8%	-1.6%	-1.0%	-0.7%	0.2%	-1.0%	0.9%	-2.0%	-0.6%
FL	-0.1%	-0.1%	0.0%	0.0%	0.4%	0.0%	0.1%	-0.2%	0.0%
GA	1.1%	1.2%	0.2%	0.3%	0.5%	0.6%	0.9%	1.6%	0.0%
KY	7.7%	0.9%	1.1%	1.0%	3.6%	1.4%	5.5%	2.4%	1.0%
MS	0.0%	-0.4%	-0.1%	-0.4%	0.5%	-0.2%	0.2%	-0.2%	-0.1%
NC	1.4%	0.7%	0.9%	0.9%	0.9%	0.9%	1.2%	1.0%	0.6%
SC	-4.1%	-0.9%	-1.7%	-1.4%	-2.1%	-2.2%	-3.7%	-1.1%	-1.3%
TN	-1.8%	0.1%	0.1%	-0.4%	-0.6%	-0.8%	-0.8%	-0.1%	0.3%
E. Central	**1.6%**	**0.1%**	**-0.1%**	**0.0%**	**0.0%**	**0.8%**	**1.2%**	**0.0%**	**0.1%**
NJ	-3.2%	-1.1%	-1.8%	-1.7%	-2.3%	-0.5%	-2.4%	0.0%	-1.3%
OH	3.0%	2.7%	1.9%	2.1%	2.7%	2.2%	3.2%	2.9%	2.5%
PA	0.4%	-0.6%	0.0%	0.1%	-0.2%	-0.3%	0.1%	-0.3%	0.3%
VA	-0.5%	-0.9%	-0.8%	-1.1%	-1.6%	-0.2%	-0.2%	-2.3%	-1.8%
WV	18.7%	-3.6%	-3.3%	-2.8%	-1.0%	5.8%	11.0%	-4.4%	-3.2%
RGGI	**-0.5%**	**0.1%**	**0.1%**	**0.1%**	**-0.1%**	**0.1%**	**0.0%**	**0.2%**	**0.2%**
CT	0.1%	-0.1%	-0.2%	1.8%	0.8%	-0.1%	0.1%	0.6%	0.7%
DE	-0.1%	0.8%	0.8%	0.5%	0.2%	0.3%	0.1%	0.7%	0.5%
ME	0.0%	1.0%	0.5%	-0.2%	-0.3%	0.1%	0.1%	0.5%	-0.2%
MA	0.1%	0.1%	0.1%	-0.3%	-0.1%	0.1%	0.0%	-0.1%	-0.1%
MD	-2.1%	0.3%	0.1%	0.0%	-0.5%	0.0%	-0.1%	0.3%	0.4%
NH	-0.4%	-0.8%	-0.5%	-0.6%	-0.3%	-0.2%	-0.1%	-0.8%	-0.4%
NY	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%
RI	0.2%	-0.1%	0.0%	-0.3%	0.0%	0.1%	0.0%	0.0%	-0.1%
VT	0.2%	0.5%	0.4%	0.4%	0.4%	0.1%	0.0%	0.5%	0.4%
N. Central	**2.0%**	**-0.1%**	**0.0%**	**-0.1%**	**-0.3%**	**-0.3%**	**-0.5%**	**-0.1%**	**0.0%**
AR	-2.9%	-2.8%	-2.2%	-2.0%	-1.7%	-2.6%	-2.9%	-3.6%	-2.4%
IL	1.9%	-1.5%	-1.1%	-0.8%	-0.9%	-0.7%	-1.0%	-1.3%	-0.7%
IN	7.1%	1.2%	1.0%	1.0%	1.0%	0.0%	0.2%	1.7%	1.6%
IA	3.1%	1.0%	1.8%	0.2%	0.4%	2.1%	2.2%	1.1%	2.4%
LA	-0.5%	0.5%	0.3%	0.2%	0.3%	0.1%	-0.1%	0.3%	0.1%
MI	0.1%	-1.4%	-1.6%	-1.6%	-2.2%	-1.3%	-2.1%	-2.1%	-1.9%
MO	1.8%	-0.5%	-0.4%	-0.5%	-0.7%	-1.1%	-1.5%	-0.9%	-0.8%
MN	1.2%	1.2%	1.1%	0.6%	0.8%	1.2%	1.3%	1.5%	1.3%
ND	20.0%	6.5%	6.4%	4.3%	4.1%	4.4%	4.7%	4.9%	4.9%
SD	-19.9%	2.0%	2.0%	3.3%	-3.9%	-4.6%	-6.7%	2.5%	1.6%
WI	3.7%	1.3%	1.1%	1.0%	0.9%	1.2%	1.4%	1.7%	1.5%
S. Central	**-1.5%**	**0.2%**	**0.4%**	**0.4%**	**0.4%**	**0.5%**	**0.2%**	**0.4%**	**0.0%**
KS	-2.4%	1.1%	1.7%	0.7%	1.5%	2.8%	4.0%	1.3%	0.1%
NE	-1.1%	2.1%	2.4%	3.5%	0.1%	2.3%	2.3%	0.1%	-0.3%
OK	-4.2%	-0.9%	0.2%	0.7%	-0.4%	-0.4%	-1.5%	-0.3%	1.0%
TX	-1.1%	0.2%	0.1%	0.1%	0.5%	0.3%	0.0%	0.4%	-0.1%

Table 5. Patchwork policy costs across scenarios with a mass cap over all units (ΔPV to 2040)

Region/state	Rate (dual)	Mass (all)	Mass (all) -- rate in nuclear states	Mass (all) -- rate in nuclear & plains	Mass (all) -- rate in nuclear, plains & Southeast	Mass (all) -- rate in nuclear, plains & East Central	Mass (all) -- rate in nuclear, plains, Southeast & East Central	4-region mass (all)	4-region mass (all) -- rate in nuclear & plains
Southeast	**0.7%**	**0.8%**	**0.2%**	**0.3%**	**0.7%**	**0.2%**	**0.9%**	**1.0%**	**0.4%**
AL	1.8%	-2.4%	-1.7%	-1.6%	1.0%	-1.7%	1.7%	-2.7%	-1.2%
FL	-0.1%	0.5%	0.3%	0.3%	0.2%	0.1%	0.3%	0.4%	0.2%
GA	1.1%	3.0%	0.0%	0.1%	0.4%	0.3%	0.7%	3.7%	-0.1%
KY	7.7%	2.9%	2.7%	2.2%	3.2%	2.4%	5.4%	3.7%	3.1%
MS	0.0%	-0.3%	-0.7%	-1.1%	0.5%	-0.5%	0.7%	-0.8%	-0.7%
NC	1.4%	1.9%	1.5%	1.5%	0.7%	1.2%	1.1%	2.2%	1.7%
SC	-4.1%	-1.7%	-2.2%	-1.7%	-1.0%	-2.4%	-2.8%	-1.4%	-1.8%
TN	-1.8%	1.4%	1.0%	1.3%	0.9%	1.1%	0.4%	1.7%	1.5%
E. Central	**1.6%**	**0.0%**	**-0.3%**	**-0.6%**	**-0.7%**	**1.1%**	**1.2%**	**0.3%**	**-0.4%**
NJ	-3.2%	-1.1%	-3.1%	-3.0%	1.2%	-0.1%	-1.6%	0.8%	-1.5%
OH	3.0%	4.1%	2.0%	1.1%	0.3%	4.1%	3.9%	3.7%	0.5%
PA	0.4%	-3.9%	-1.5%	-0.9%	-2.2%	-1.0%	-0.7%	-2.5%	0.2%
VA	-0.5%	1.3%	0.9%	0.0%	-0.2%	-0.8%	-0.8%	0.3%	-0.7%
WV	18.7%	-4.1%	-4.8%	-3.5%	-4.0%	5.4%	10.6%	-5.0%	-3.4%
RGGI	**-0.5%**	**0.7%**	**0.6%**	**0.6%**	**-0.1%**	**0.0%**	**-0.1%**	**0.5%**	**0.3%**
CT	0.1%	-2.0%	-0.9%	-0.8%	-0.7%	-1.0%	-0.9%	-1.1%	0.2%
DE	-0.1%	1.0%	0.5%	0.5%	-1.1%	-0.7%	-0.8%	2.1%	1.4%
ME	0.0%	0.3%	-1.2%	-0.6%	-0.2%	-0.5%	-0.4%	4.2%	2.2%
MA	0.1%	1.5%	0.8%	0.7%	0.6%	0.8%	0.7%	0.5%	-0.1%
MD	-2.1%	3.2%	2.5%	2.4%	0.3%	0.5%	0.2%	2.0%	0.9%
NH	-0.4%	-7.4%	-4.3%	-3.6%	-2.4%	-3.3%	-2.8%	-3.1%	-0.9%
NY	0.1%	-0.4%	-0.2%	-0.1%	-0.3%	-0.2%	-0.3%	-0.3%	-0.2%
RI	0.2%	-1.3%	-0.8%	-0.6%	-0.5%	-0.6%	-0.5%	-0.7%	-0.2%
VT	0.2%	2.4%	1.4%	1.0%	0.4%	0.7%	0.7%	1.2%	0.4%
N. Central	**2.0%**	**0.0%**	**0.2%**	**0.0%**	**-0.4%**	**-0.6%**	**-1.0%**	**-0.2%**	**0.2%**
AR	-2.9%	-5.6%	-5.8%	-7.6%	-6.3%	-6.6%	-6.8%	-8.0%	-8.5%
IL	1.9%	-3.0%	-2.0%	-1.6%	-0.5%	-0.8%	-0.9%	-3.0%	-1.6%
IN	7.1%	2.5%	1.9%	1.6%	1.3%	1.1%	-0.6%	3.3%	2.1%
IA	3.1%	-0.6%	0.7%	1.6%	0.9%	2.3%	0.3%	-0.5%	1.5%
LA	-0.5%	1.1%	0.8%	0.4%	0.0%	0.3%	0.0%	0.9%	0.3%
MI	0.1%	-1.6%	-0.4%	0.6%	-1.8%	-3.0%	-2.6%	-2.9%	0.9%
MO	1.8%	-1.1%	-0.4%	-0.9%	-1.0%	-1.2%	-1.3%	-1.4%	-1.3%
MN	1.2%	2.6%	1.8%	1.5%	1.3%	1.3%	0.8%	3.0%	1.8%
ND	20.0%	12.7%	11.7%	4.0%	2.7%	3.8%	2.5%	9.4%	11.5%
SD	-19.9%	11.4%	4.3%	2.3%	-1.8%	-6.4%	-9.4%	15.9%	2.9%
WI	3.7%	2.6%	1.7%	1.4%	1.2%	1.3%	1.2%	2.8%	2.2%
S. Central	**-1.5%**	**0.9%**	**0.7%**	**0.6%**	**0.8%**	**0.5%**	**0.4%**	**1.2%**	**0.4%**
KS	-2.4%	9.5%	6.0%	2.2%	1.5%	2.4%	5.5%	8.6%	0.5%
NE	-1.1%	3.4%	2.6%	3.4%	3.1%	0.9%	1.6%	3.2%	2.5%
OK	-4.2%	-2.6%	-2.1%	2.0%	0.7%	1.0%	-1.3%	-0.7%	2.1%
TX	-1.1%	0.5%	0.5%	0.0%	0.5%	0.2%	0.1%	0.6%	0.0%

One outcome of interest is potential generation shifts between rate-based states and mass-based states in response to patchwork choices whereby neighboring states adopt different approaches. Figure 44 examines the aggregate shifts by looking at some of the possible outcomes for generation in the eastern half of the United States. If all states, aside from California and the RGGI states, pursue the mass cap over existing units ("National Mass (exist)"), allowance prices would be $6.8/ton in 2030, leading to coal generation of 1,080 TWh and gas generation of 1,020 TWh in the East. A national mass cap over all units would raise the allowance price to $14.5/ton, lowering coal generation by some 10% and raising gas generation by a similar amount. If the eastern states form a trading block to trade mass allowances over existing units ("E. Mass (exist)"), the allowance price in the East would decline from $6.8/ton under the national approach to $5.2/ton, leading to an increase in coal generation (the shift from the solid black square to the solid red square). Compared to a national NSC approach, a mass cap over all units would also lead to an allowance price decrease and coal generation increase in eastern states. If those states divided into four regional trading blocks for mass allowances, impacts on generation would not be significant.

Once some states in the East move away from a consistent mass-based policy, generation outcomes become less clear. Incentives in the dual-rate approaches can potentially shift coal generation into rate-based states, where fossil generation can be offset by available ERCs. This incentive structure is particularly evident in a rate-based policy that has low ERC prices such as a patchwork rate-based approach covering only nuclear and plains states. These incentives and generation shifts interact with mass allowance prices in the surrounding states and, if they lead to higher allowance prices, can increase the cost of fossil generation in mass-based states. In some cases, compared with coal generation under a mass cap over existing units, total regional coal generation under a mass cap with NSC can increase as that generation shifts to the rate-based states.

Figure 44. Fossil generation in the eastern United States across alternative state patchwork choices (2030)

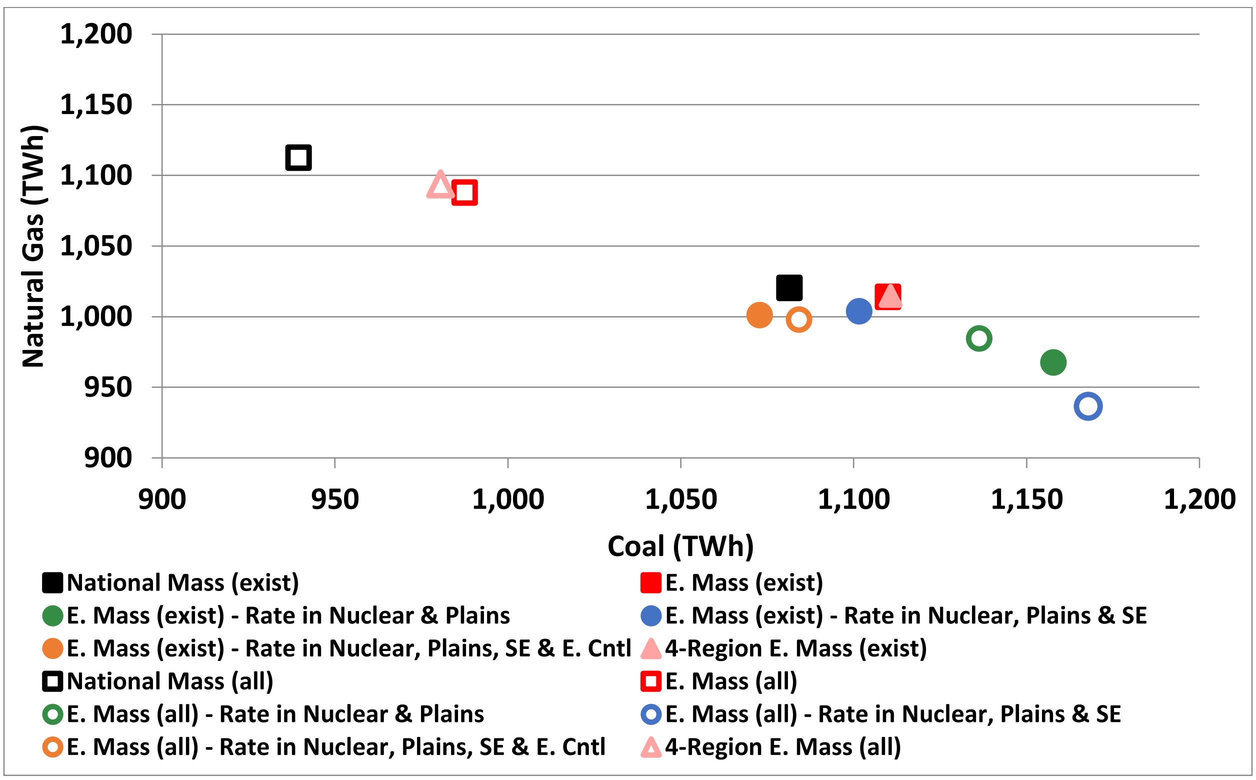
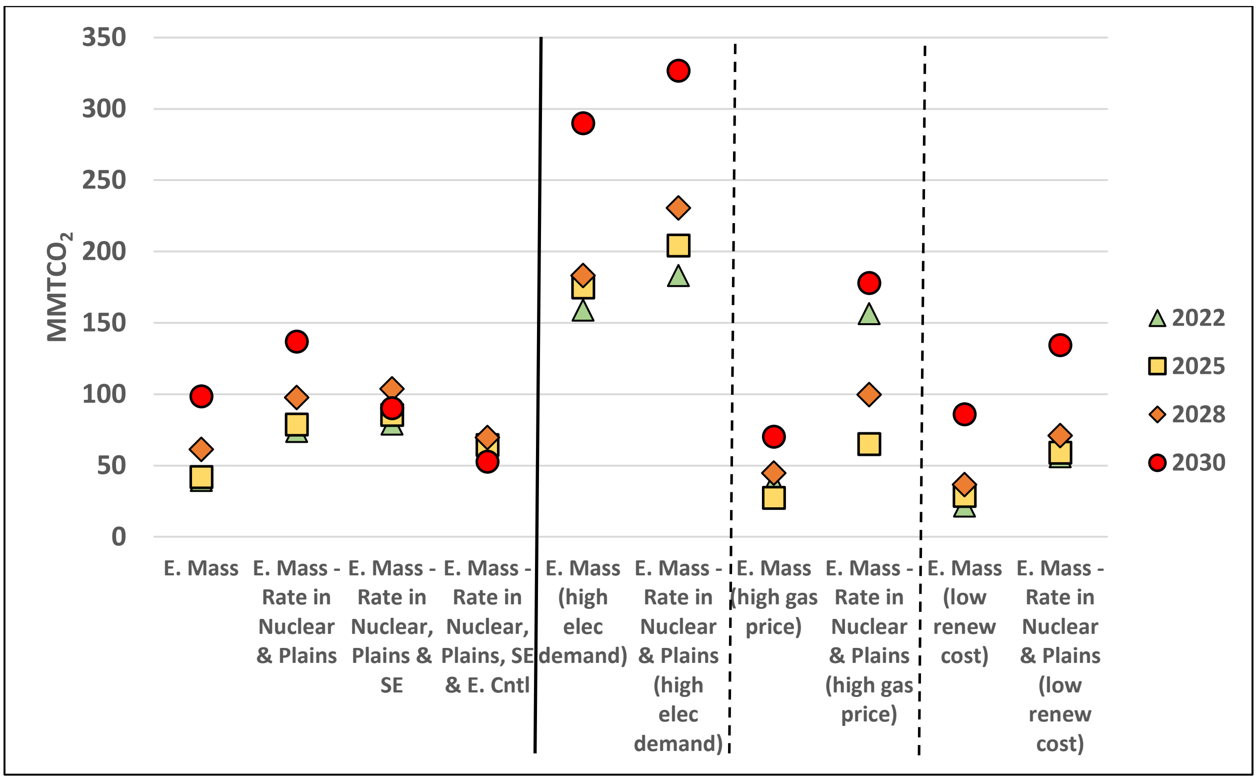


Figure 45 examines the emissions consequences in the eastern United States of any generation shifting among states that may occur as a result of non-coordinated policy choices. The four columns on the left-hand side of the figure show how emissions leakage, relative to leakage under a mass cap over all units, may increase as states choose to leave the mass cap over existing units and enter into rate-based trading. If nuclear states as well as plains states with abundant ERCs adopt a rate-based approach, rather than participate in mass-based trading, leakage in the East would increase from 100 $MMTCO_2$ to almost 150 $MMTCO_2$.

Then, as additional states (Southeast and East Central states) participate in the rate-based trading, leakage declines to a level lower than that when all states used a consistent mass cap over existing units. This result is similar to that shown in the national leakage figures, reflecting that a national rate policy results in the same level of emissions as a national mass policy over all units (defined as zero leakage). However, this leakage result is predicated on the model's set of standard assumptions about future market conditions. Thus, the final six columns in the graph compare how leakage in the East changes across several sensitivities, depending on whether all states participate in the mass cap over existing units or if the nuclear and plains states choose a rate-based approach. The difference in leakage between the two sets of states' choices can depend fairly significantly on the expected market conditions for electricity demand and gas prices.

Figure 45. Leakage from eastern states' mass cap over existing units with patchwork rate-based choices



CONCLUSIONS

Since 2000, the electricity generation mix has evolved from a mostly coal-based mix to a much more diversified mix. Natural gas and renewables have been growing at a rapid rate due to changes in fuel prices, environmental regulations, technologies, and non-fossil-generation costs. The diversification trend will continue under the Clean Power Plan, which will build on trends within the electricity industry that are already reducing CO_2 emissions.

This paper suggests how the industry may respond to ongoing trends, both without and with the CPP policy. Using the electricity dispatch component of the DIEM model, it examines several potential pathways to achieve the CPP emissions goals: (1) the dual-rate option with separate emissions rate targets for existing fossil steam units and for NGCC units, (2) a mass-based cap over existing units only, and (3) a mass-based cap covering new fossil units (the NSC).

In the absence of the CPP policy, it appears that the largest driver of CO_2 emissions from the electricity industry will be natural gas prices. Low gas prices could lead to significant declines in emissions, compared with today's levels, over the next decade and could even reduce emissions below the CPP mass goals for a number of years. The extension of federal PTC/ITC credits for renewable generation is likely to increase total capacity of wind and solar by 15–40 GW in the near future. If its costs continue to decline, solar PV generation will become increasingly cost competitive based on its economics, even without subsidies or emissions limits in the sector. But given the most probable future trends, additional measures such as the Clean Power Plan would likely be needed to decrease electricity generation emissions.

In the presence of the CPP policy, policy costs depend in part on whether states take a coordinated, national approach to the policy or a less coordinated, patchwork approach. This analysis's modeling finds that national costs for the policy are very low, on the order of 0.1%–1.0% above baseline levels across most assumptions about future industry trends. The mass-based policy including the NSC has costs comparable to those of the dual-rate approach: both entail industry cost increases of 0.5%–0.7% in present value terms over the next couple of decades. A mass cap over only existing units has the lowest costs, but it also achieves the smallest emissions reductions of the three analyzed options. Policy costs can vary with future market conditions for gas prices, energy efficiency availability, and renewables costs. However, the mass-based options have the least variable costs in the face of future uncertainties.

Policy costs can vary significantly across individual states and regions. Actions of neighboring states can potentially affect a state's costs as much as any actions taken within a state. A patchwork approach to the Clean Power Plan could materialize as states choose policy options that appear to be in their best interests. But identifying "best" options is difficult because impacts depend on the actions of other states. Moreover, state-level results of electricity dispatch modeling must be interpreted with caution. Some states are clearly better off under one approach than another, and the results presented here clearly show where that is the case. But for many states, net impacts are relatively small and variable across policy scenarios and thus clear-cut implications of policy choices for those states can be difficult to identify.

One concern about the CPP policy is the potential for leakage of emissions from the existing units covered by most CPP options to new units that would be covered only under a NSC policy. Because generation could shift from mass-based states to rate-based states under a patchwork approach, additional emissions leakage could occur. Compared with the mass policy with the NSC, a dual-rate approach may not lead to additional emissions but this possibility may arise only as a matter of coincidence and appears to depend on a specific set of future market conditions for natural gas prices and on other factors that may not occur.

APPENDIX A

The tables below indicate highest-cost (in red) and lowest-cost (in green) outcomes for each region or state. They reflect the results of sensitivity analyses of state-level policy costs for national approaches to the CPP policy.

Table A-1. State policy costs of a national mass cap over existing units (change in present value to 2040)

Region/state	Standard assumptions	High gas price	Low gas price	High elec demand	Low elec demand	Low renew cost	Low EE
USA	**0.1%**	**3.1%**	**0.0%**	**0.1%**	**0.1%**	**0.1%**	**0.3%**
Southeast	**0.1%**	**3.6%**	**0.1%**	**0.0%**	**0.1%**	**0.2%**	**0.1%**
AL	-1.7%	-3.4%	0.4%	-1.8%	-1.1%	1.3%	-3.8%
FL	-0.1%	4.8%	-0.1%	-0.5%	0.0%	-0.2%	0.2%
GA	1.4%	6.6%	0.2%	1.2%	1.4%	1.1%	2.4%
KY	0.8%	5.9%	0.1%	1.4%	1.7%	0.9%	1.4%
MS	-0.3%	5.4%	-0.1%	-0.4%	-0.4%	-0.3%	-0.7%
NC	0.8%	3.1%	0.0%	0.6%	0.5%	0.2%	0.5%
SC	-1.1%	-2.2%	0.2%	0.2%	-1.6%	-1.8%	-1.0%
TN	0.0%	5.2%	0.0%	-0.1%	-0.1%	0.2%	0.2%
East Central	**0.1%**	**2.6%**	**-0.1%**	**-0.2%**	**-0.4%**	**-0.5%**	**0.1%**
NJ	-1.0%	0.8%	0.1%	-1.7%	-0.9%	-1.5%	-1.2%
OH	3.0%	7.5%	0.5%	0.4%	1.0%	0.0%	2.9%
PA	-0.9%	-3.2%	-0.2%	1.6%	-1.1%	0.3%	-1.1%
VA	-1.1%	5.1%	-1.3%	-0.3%	-0.2%	0.4%	-0.7%
WV	-2.7%	-3.0%	1.1%	-6.4%	-3.4%	-6.0%	-3.3%
RGGI	**0.1%**	**4.8%**	**-0.1%**	**0.1%**	**0.1%**	**0.7%**	**0.8%**
CT	0.2%	1.3%	0.0%	-0.6%	-0.2%	1.1%	-1.1%
DE	0.9%	5.4%	-0.2%	0.4%	1.1%	1.8%	2.0%
ME	1.3%	4.7%	0.6%	0.8%	1.6%	0.1%	3.7%
MA	0.1%	6.4%	-0.1%	-0.2%	0.2%	0.0%	0.9%
MD	0.1%	4.2%	-0.2%	-0.2%	0.4%	1.1%	1.9%
NH	-1.3%	-10.3%	0.1%	-1.3%	-1.4%	-0.1%	-4.0%
NY	0.0%	6.2%	0.0%	0.7%	-0.1%	0.5%	0.3%
RI	-0.3%	5.9%	-0.1%	-0.5%	-0.5%	0.0%	-0.7%
VT	0.6%	5.2%	0.1%	0.4%	1.5%	0.6%	2.2%

Table A-2. State policy costs of a national mass cap over existing units (change in present value to 2040)

Region/state	Standard assumptions	High gas price	Low gas price	High elec demand	Low elec demand	Low renew cost	Low EE
North Central	**-0.1%**	**1.6%**	**0.0%**	**-0.1%**	**0.1%**	**0.1%**	**0.3%**
AR	-3.1%	-7.0%	0.0%	-2.4%	-2.4%	-1.6%	-4.6%
IL	-1.5%	-4.5%	0.1%	-3.5%	-1.8%	-1.5%	-1.8%
IN	1.4%	7.4%	0.1%	4.0%	1.7%	2.7%	4.9%
IA	1.1%	-1.1%	0.2%	-0.1%	0.1%	0.9%	0.4%
LA	0.4%	5.1%	-0.1%	-0.2%	0.4%	0.3%	0.9%
MI	-1.4%	0.2%	0.0%	-1.7%	0.8%	-1.7%	-3.1%
MO	-0.8%	1.4%	-0.2%	-1.4%	-0.6%	-0.4%	-0.2%
MN	1.2%	5.2%	0.1%	0.7%	1.6%	1.0%	1.8%
ND	5.2%	-9.1%	-0.7%	14.2%	0.9%	2.0%	8.8%
SD	2.2%	-5.9%	0.0%	7.9%	-1.0%	9.1%	0.5%
WI	1.4%	7.0%	-0.1%	2.1%	1.2%	0.9%	2.4%
South Central	**0.2%**	**2.9%**	**-0.1%**	**0.5%**	**0.2%**	**0.0%**	**0.5%**
KS	1.3%	-1.8%	0.1%	4.7%	0.8%	1.1%	4.0%
NE	2.1%	-1.4%	-0.5%	2.1%	0.2%	-0.2%	2.5%
OK	-1.0%	-1.0%	0.3%	-0.8%	-1.3%	-0.1%	-2.5%
TX	0.1%	4.2%	-0.1%	0.2%	0.4%	-0.1%	0.5%
West	**-0.3%**	**0.5%**	**0.0%**	**0.0%**	**-0.3%**	**-0.4%**	**0.3%**
AZ	-0.6%	-0.8%	0.0%	1.1%	-0.6%	-0.5%	0.2%
CO	0.8%	4.5%	0.1%	0.5%	1.0%	0.2%	0.8%
ID	1.5%	6.3%	-0.1%	0.0%	1.3%	0.7%	3.4%
MT	0.8%	12.1%	0.5%	3.4%	1.4%	0.8%	2.2%
NM	-1.7%	-2.5%	0.0%	-6.0%	-1.7%	-1.1%	-2.0%
NV	0.4%	4.8%	0.1%	1.1%	0.6%	0.1%	1.9%
OR	-1.5%	-7.1%	-0.1%	-1.1%	-2.7%	-1.6%	-2.2%
UT	1.0%	5.5%	0.0%	-0.7%	0.9%	-0.6%	2.2%
WA	-2.5%	-12.1%	-0.2%	-1.1%	-3.2%	-1.9%	-2.4%
WY	-1.0%	-2.1%	-0.1%	4.7%	-1.0%	0.6%	-3.3%
California	**0.9%**	**7.1%**	**0.0%**	**0.8%**	**0.6%**	**0.6%**	**0.4%**

Table A-3. State policy costs of national mass over all units (change in present value to 2040)

Region/state	Standard assumptions	High gas price	Low gas price	High elec demand	Low elec demand	Low renew cost	Low EE
USA	**0.5%**	**3.6%**	**0.1%**	**1.6%**	**0.3%**	**0.2%**	**1.1%**
Southeast	**0.9%**	**4.8%**	**0.0%**	**2.1%**	**0.6%**	**0.6%**	**1.3%**
AL	-2.5%	-2.0%	0.4%	-2.6%	-1.6%	-0.3%	-4.9%
FL	0.5%	5.8%	-0.2%	0.6%	0.2%	0.5%	1.0%
GA	3.2%	8.3%	0.8%	6.4%	2.4%	1.5%	4.8%
KY	2.9%	7.8%	0.9%	4.2%	2.6%	0.8%	4.2%
MS	-0.4%	6.4%	-0.6%	0.4%	-0.2%	0.0%	-0.4%
NC	2.0%	4.0%	-0.8%	3.3%	1.1%	1.5%	2.5%
SC	-1.5%	-2.3%	-1.0%	-0.1%	-1.8%	-1.2%	-2.1%
TN	1.6%	7.3%	0.7%	4.2%	0.9%	1.0%	3.1%
East Central	**0.0%**	**2.2%**	**-0.1%**	**1.1%**	**-0.5%**	**-0.2%**	**0.6%**
NJ	-1.1%	0.8%	0.3%	-1.8%	-0.8%	-1.7%	-1.3%
OH	4.4%	7.1%	2.6%	5.0%	1.7%	0.8%	6.2%
PA	-4.4%	-6.3%	-2.2%	-2.6%	-3.8%	-1.0%	-5.2%
VA	1.4%	8.2%	-2.3%	3.7%	2.1%	2.5%	2.4%
WV	-4.1%	-7.1%	3.0%	-4.8%	-5.5%	-7.8%	-4.4%
RGGI	**0.7%**	**5.4%**	**0.0%**	**2.0%**	**0.5%**	**0.8%**	**1.8%**
CT	-2.1%	0.5%	0.0%	-1.7%	-1.6%	0.5%	-2.1%
DE	1.1%	7.3%	-0.2%	2.8%	1.0%	1.4%	2.8%
ME	0.4%	5.6%	-1.6%	-4.3%	-0.3%	-0.7%	-0.1%
MA	1.6%	7.8%	0.5%	1.9%	1.1%	0.8%	2.8%
MD	3.4%	8.0%	0.0%	4.7%	2.8%	2.2%	5.8%
NH	-8.0%	-18.1%	-1.2%	-10.5%	-6.8%	-2.9%	-12.5%
NY	-0.4%	4.9%	0.1%	2.4%	-0.5%	0.2%	0.3%
RI	-1.4%	4.4%	-0.2%	-1.2%	-1.4%	-0.6%	-1.9%
VT	2.7%	8.0%	0.5%	4.1%	3.1%	1.1%	5.4%

Table A-4. State policy costs of a national mass cap over all units (change in present value to 2040)

Region/state	Standard assumptions	High gas price	Low gas price	High elec demand	Low elec demand	Low renew cost	Low EE
North Central	**0.0%**	**2.6%**	**0.2%**	**0.4%**	**0.2%**	**-0.3%**	**0.5%**
AR	-6.1%	-9.0%	-0.4%	-7.8%	-5.0%	-3.9%	-7.8%
IL	-3.3%	-6.3%	-0.4%	-5.1%	-3.2%	-2.3%	-3.7%
IN	2.8%	13.9%	1.1%	8.2%	2.7%	2.5%	6.2%
IA	-0.8%	-4.4%	1.3%	1.9%	-0.5%	0.1%	-1.2%
LA	1.2%	7.7%	0.3%	2.2%	1.0%	0.7%	2.5%
MI	-1.8%	1.1%	0.0%	-3.7%	0.1%	-2.0%	-3.1%
MO	-1.4%	1.8%	-1.1%	-3.7%	-1.3%	-1.0%	-0.4%
MN	2.7%	5.9%	1.1%	4.2%	2.4%	1.7%	4.1%
ND	11.9%	-16.3%	-1.6%	11.9%	9.5%	-0.5%	5.8%
SD	12.1%	-12.0%	0.4%	12.0%	9.7%	7.8%	9.7%
WI	2.8%	8.0%	0.8%	6.1%	2.0%	1.0%	4.6%
South Central	**0.8%**	**2.0%**	**-0.1%**	**1.3%**	**0.8%**	**0.5%**	**1.5%**
KS	9.4%	-3.3%	1.3%	8.8%	7.2%	3.8%	6.5%
NE	2.9%	-3.3%	-0.7%	-2.4%	3.7%	2.3%	1.4%
OK	-2.9%	-2.1%	-0.9%	-2.6%	-2.3%	-0.8%	-3.5%
TX	0.5%	3.5%	0.0%	1.6%	0.4%	0.3%	1.9%
West	**0.0%**	**1.8%**	**0.1%**	**1.3%**	**-0.2%**	**-0.2%**	**0.9%**
AZ	0.4%	2.4%	-0.1%	3.3%	0.0%	0.5%	1.2%
CO	1.5%	4.0%	0.3%	2.9%	1.3%	0.6%	2.2%
ID	4.5%	9.1%	0.8%	6.4%	2.7%	1.7%	8.0%
MT	0.4%	7.6%	1.9%	5.3%	-0.1%	-0.3%	-0.1%
NM	5.0%	12.2%	0.6%	3.4%	4.2%	2.5%	7.3%
NV	-0.1%	3.9%	0.6%	-1.0%	0.3%	-0.7%	1.3%
OR	-5.9%	-9.4%	-1.7%	-3.7%	-5.6%	-2.9%	-6.3%
UT	3.0%	8.7%	0.5%	2.8%	2.5%	0.4%	4.5%
WA	-6.3%	-14.9%	-1.1%	-3.3%	-6.3%	-3.3%	-5.5%
WY	-9.4%	-17.8%	0.6%	-9.9%	-6.7%	-4.0%	-14.1%
California	**2.0%**	**7.3%**	**0.8%**	**4.8%**	**1.2%**	**0.3%**	**2.2%**

Table A-5. State policy costs of national dual-rate (change in present value to 2040)

Region/state	Standard assumptions	High gas price	Low gas price	High elec demand	Low elec demand	Low renew cost	Low EE
USA	**0.7%**	**2.4%**	**0.4%**	**0.5%**	**0.7%**	**0.2%**	**1.5%**
Southeast	**0.7%**	**3.0%**	**-0.3%**	**0.6%**	**0.7%**	**0.3%**	**2.2%**
AL	1.8%	3.5%	1.8%	1.3%	2.6%	0.7%	3.1%
FL	0.0%	4.3%	-0.8%	0.1%	-0.1%	-0.2%	1.2%
GA	0.7%	2.1%	0.2%	0.7%	1.2%	0.6%	3.2%
KY	8.2%	8.5%	3.6%	5.8%	8.9%	3.5%	12.5%
MS	0.5%	5.9%	-0.7%	0.5%	0.4%	0.2%	1.2%
NC	1.2%	0.5%	-0.7%	0.8%	1.0%	0.1%	2.2%
SC	-4.1%	-3.6%	-4.8%	-2.8%	-5.1%	-1.5%	-5.1%
TN	-2.1%	1.7%	-0.7%	-0.9%	-2.6%	0.0%	-0.7%
East Central	**1.5%**	**2.7%**	**0.4%**	**1.0%**	**1.7%**	**0.8%**	**4.1%**
NJ	-3.5%	-1.1%	-0.9%	-4.0%	-3.0%	-2.7%	-4.4%
OH	3.4%	3.9%	2.0%	2.2%	3.3%	1.4%	8.2%
PA	0.0%	0.9%	-1.4%	1.5%	-0.3%	0.9%	1.9%
VA	-0.6%	2.8%	-2.6%	-0.7%	-0.6%	0.9%	-0.4%
WV	18.8%	13.9%	13.3%	9.7%	22.4%	4.7%	31.4%
RGGI	**-0.6%**	**2.5%**	**-0.6%**	**-0.4%**	**-0.7%**	**0.0%**	**-0.2%**
CT	0.1%	2.1%	0.2%	-0.1%	0.2%	1.0%	-0.4%
DE	-0.2%	1.1%	-0.4%	-0.8%	-0.2%	0.0%	-0.1%
ME	0.0%	4.6%	-1.1%	0.7%	0.1%	-0.1%	-0.3%
MA	0.1%	6.0%	0.0%	-0.1%	0.1%	-0.2%	0.8%
MD	-2.2%	0.2%	-2.4%	-1.6%	-2.5%	0.0%	-1.6%
NH	-0.3%	-4.9%	0.4%	0.1%	-0.1%	-0.5%	-2.3%
NY	0.1%	2.9%	0.2%	0.2%	0.1%	0.0%	0.5%
RI	0.2%	6.2%	0.1%	-0.1%	0.1%	-0.1%	-0.3%
VT	0.1%	3.1%	0.0%	-0.2%	-1.1%	0.5%	1.6%

Table A-6. State policy costs of national dual-rate (change in present value to 2040)

Region/state	Standard assumptions	High gas price	Low gas price	High elec demand	Low elec demand	Low renew cost	Low EE
North Central	**1.7%**	**3.4%**	**1.6%**	**1.2%**	**2.3%**	**0.6%**	**3.8%**
AR	-2.5%	-2.3%	-0.4%	-1.3%	-2.7%	-2.0%	-1.7%
IL	2.0%	1.7%	2.0%	1.5%	2.5%	0.8%	5.4%
IN	6.9%	8.5%	4.4%	5.1%	8.9%	3.5%	13.5%
IA	-1.7%	-1.5%	0.1%	-5.4%	-1.5%	2.1%	-5.9%
LA	-1.2%	4.6%	-0.7%	-0.9%	-0.9%	-0.3%	0.6%
MI	0.0%	1.8%	-0.7%	-0.3%	1.4%	-0.9%	1.0%
MO	2.3%	6.0%	0.7%	2.2%	2.8%	0.6%	6.0%
MN	-0.2%	1.2%	2.1%	-1.2%	0.3%	0.6%	2.6%
ND	18.8%	5.8%	14.4%	20.0%	11.5%	0.3%	-5.9%
SD	-22.1%	-24.5%	2.1%	-12.0%	-22.3%	-7.2%	-50.4%
WI	4.1%	5.3%	3.1%	3.7%	3.8%	1.3%	6.8%
South Central	**-1.3%**	**-0.9%**	**-0.6%**	**-0.8%**	**-1.9%**	**-1.1%**	**-4.7%**
KS	1.0%	-8.2%	6.7%	2.5%	-1.9%	-2.1%	-16.0%
NE	-0.8%	-5.3%	1.0%	-4.3%	-2.5%	-2.9%	-13.9%
OK	-4.2%	-3.9%	-2.8%	-3.4%	-4.5%	-1.8%	-7.1%
TX	-1.0%	0.6%	-1.1%	-0.4%	-1.4%	-0.8%	-2.6%
West	**2.0%**	**1.5%**	**2.2%**	**1.0%**	**1.7%**	**0.4%**	**3.1%**
AZ	0.9%	1.1%	1.4%	0.1%	-0.3%	0.8%	2.0%
CO	2.9%	3.4%	2.1%	1.3%	1.4%	-0.6%	3.3%
ID	-4.2%	-5.6%	-3.6%	-5.4%	-4.5%	-4.0%	-2.3%
MT	22.3%	29.1%	23.7%	16.9%	32.9%	10.2%	21.9%
NM	0.4%	-3.5%	1.4%	0.3%	1.0%	1.1%	-1.8%
NV	-3.8%	-0.4%	-1.6%	-1.7%	-3.5%	-2.1%	-6.1%
OR	-9.0%	-7.2%	-5.0%	-4.9%	-10.2%	-3.4%	-7.3%
UT	12.6%	9.5%	5.9%	7.0%	13.4%	3.0%	20.3%
WA	-11.6%	-13.4%	-5.9%	-7.4%	-13.4%	-4.3%	-9.1%
WY	58.0%	61.1%	38.8%	45.5%	60.9%	23.5%	60.1%
California	**-0.2%**	**4.8%**	**0.1%**	**-0.2%**	**-0.4%**	**-1.0%**	**-0.9%**

APPENDIX B

Tables indicate highest-cost (in red) and lowest-cost (in green) outcomes of patchwork policy approaches.

Table B-1. Costs of mass cap (existing) in eastern states, rate in nuclear and plains states (ΔPV to 2040)

Region/state	Standard assumptions	High gas price	Low gas price	High elec demand	Low elec demand	Low renewable cost	Low EE
Southeast	**0.0%**	**0.1%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
AL	-0.7%	-2.0%	0.1%	-0.9%	0.1%	1.4%	-2.3%
FL	0.0%	-0.1%	0.0%	-0.5%	0.0%	-0.2%	0.4%
GA	0.3%	0.4%	0.3%	0.2%	0.3%	0.0%	1.0%
KY	1.0%	2.8%	0.2%	0.7%	1.5%	0.8%	1.2%
MS	-0.4%	-0.9%	-0.2%	-0.1%	-0.3%	-0.3%	-0.5%
NC	0.9%	0.8%	-0.1%	0.6%	0.3%	0.0%	0.4%
SC	-1.4%	-2.0%	-0.6%	-0.2%	-2.2%	-1.5%	-2.3%
TN	-0.4%	0.6%	0.0%	0.4%	-0.4%	0.0%	0.4%
E. Central	**0.0%**	**1.4%**	**-0.1%**	**-0.4%**	**-0.3%**	**-0.2%**	**0.3%**
NJ	-1.7%	-5.5%	0.0%	-3.4%	-1.3%	-1.9%	-2.6%
OH	2.1%	3.3%	0.1%	-0.5%	0.5%	-0.1%	3.4%
PA	0.1%	3.1%	0.0%	2.5%	-0.3%	0.9%	0.4%
VA	-1.1%	0.8%	-0.8%	-0.4%	0.1%	1.0%	-1.4%
WV	-2.8%	5.3%	0.5%	-4.6%	-3.3%	-5.4%	-3.1%
RGGI	**0.1%**	**0.1%**	**-0.1%**	**0.0%**	**0.1%**	**0.4%**	**0.3%**
CT	1.8%	-0.2%	0.0%	-0.4%	0.2%	1.0%	-0.6%
DE	0.5%	0.9%	-0.2%	0.1%	0.7%	1.2%	1.0%
ME	-0.2%	1.1%	0.2%	0.6%	-0.3%	0.1%	3.1%
MA	-0.3%	0.4%	-0.1%	-0.1%	0.1%	-0.1%	0.3%
MD	0.0%	0.2%	-0.3%	-0.4%	0.2%	0.8%	0.5%
NH	-0.6%	-1.6%	0.1%	-0.8%	-0.6%	-0.1%	-1.2%
NY	0.1%	0.0%	0.1%	0.5%	0.0%	0.2%	0.3%
RI	-0.3%	0.2%	-0.1%	-0.3%	0.0%	0.0%	-0.3%
VT	0.4%	0.8%	0.1%	0.1%	1.1%	0.9%	0.9%
N. Central	**-0.1%**	**-0.3%**	**0.0%**	**0.0%**	**0.1%**	**0.2%**	**0.1%**
AR	-2.0%	-3.3%	-0.2%	-1.6%	-1.6%	-1.2%	-2.7%
IL	-0.8%	-2.6%	-0.1%	-2.4%	-0.9%	-0.7%	-1.1%
IN	1.0%	3.5%	-0.1%	3.4%	1.6%	2.8%	3.2%
IA	0.2%	1.5%	0.0%	1.6%	-0.3%	1.9%	-0.6%
LA	0.2%	-0.5%	0.0%	-0.2%	0.3%	0.1%	0.7%
MI	-1.6%	-1.5%	0.0%	-0.7%	0.2%	-1.9%	-2.6%
MO	-0.5%	-3.7%	0.1%	-3.7%	-0.5%	-0.5%	-0.1%
MN	0.6%	2.0%	0.6%	0.7%	1.0%	0.9%	1.4%
ND	4.3%	-0.3%	-1.5%	14.4%	0.4%	1.9%	2.8%
SD	3.3%	3.1%	0.3%	7.3%	-2.2%	2.0%	-5.6%
WI	1.0%	3.0%	-0.3%	1.7%	0.9%	0.6%	1.5%
S. Central	**0.4%**	**-0.2%**	**0.3%**	**0.4%**	**0.6%**	**-0.2%**	**1.1%**
KS	0.7%	-1.5%	1.7%	4.2%	1.1%	-0.1%	1.9%
NE	3.5%	-0.5%	0.9%	3.6%	3.1%	0.0%	3.2%
OK	0.7%	0.7%	-0.4%	0.2%	0.5%	-0.3%	-0.4%
TX	0.1%	-0.2%	0.2%	-0.1%	0.3%	-0.2%	1.1%

Table B-2. Costs of mass cap (all) in eastern states, rate in nuclear and plains states (ΔPV to 2040)

Region/state	Standard assumptions	High gas price	Low gas price	High elec demand	Low elec demand	Low renewable cost	Low EE
Southeast	**0.3%**	**0.6%**	**-0.2%**	**0.5%**	**0.3%**	**0.1%**	**0.5%**
AL	-1.6%	-2.3%	0.3%	-0.5%	-0.9%	-0.5%	-3.0%
FL	0.3%	0.5%	-0.2%	0.3%	0.1%	0.2%	1.0%
GA	0.1%	0.2%	0.4%	0.3%	0.3%	0.0%	0.8%
KY	2.2%	4.8%	0.3%	2.6%	2.5%	1.6%	2.5%
MS	-1.1%	-0.5%	-0.4%	-0.1%	-0.5%	-0.1%	-0.9%
NC	1.5%	1.9%	0.0%	3.5%	0.8%	0.8%	2.5%
SC	-1.7%	-1.5%	-2.7%	-5.6%	-1.2%	-3.0%	-3.9%
TN	1.3%	1.3%	0.2%	1.7%	0.4%	0.7%	1.3%
E. Central	**-0.6%**	**0.8%**	**0.2%**	**0.5%**	**-0.4%**	**0.1%**	**0.2%**
NJ	-3.0%	-6.2%	-0.1%	-7.8%	-1.7%	-1.7%	-3.1%
OH	1.1%	2.7%	1.3%	3.1%	0.6%	0.5%	3.6%
PA	-0.9%	0.2%	-0.7%	1.5%	-1.0%	0.0%	-1.5%
VA	0.0%	3.6%	-0.5%	2.2%	0.8%	2.6%	1.0%
WV	-3.5%	1.1%	2.0%	-2.7%	-5.0%	-6.3%	-4.5%
RGGI	**0.6%**	**0.9%**	**-0.1%**	**1.3%**	**0.3%**	**0.5%**	**1.1%**
CT	-0.8%	-0.8%	0.1%	-1.0%	-0.7%	0.8%	-1.2%
DE	0.5%	1.5%	-0.2%	-0.2%	0.3%	0.6%	0.7%
ME	-0.6%	-0.5%	-1.0%	-1.7%	-0.6%	-0.1%	0.0%
MA	0.7%	2.3%	0.1%	1.6%	0.5%	0.7%	1.6%
MD	2.4%	3.8%	-0.4%	3.7%	1.5%	1.6%	3.4%
NH	-3.6%	-8.3%	-0.1%	-5.6%	-2.8%	-2.5%	-6.0%
NY	-0.1%	-1.0%	0.1%	1.0%	-0.3%	-0.2%	0.3%
RI	-0.6%	-0.6%	0.0%	-0.6%	-0.5%	-0.6%	-0.8%
VT	1.0%	2.5%	0.0%	1.8%	1.7%	1.6%	2.7%
N. Central	**0.0%**	**-0.2%**	**0.0%**	**0.1%**	**-0.1%**	**-0.3%**	**0.2%**
AR	-7.6%	-8.7%	-0.6%	-9.6%	-5.8%	-5.7%	-8.5%
IL	-1.6%	-4.5%	-0.4%	-3.5%	-1.3%	-1.4%	-2.0%
IN	1.6%	4.4%	0.3%	4.9%	1.8%	2.3%	3.2%
IA	1.6%	0.5%	0.4%	0.7%	-0.6%	1.4%	-0.2%
LA	0.4%	0.2%	0.2%	0.8%	0.5%	0.5%	1.3%
MI	0.6%	1.2%	0.3%	-0.1%	-0.3%	-2.1%	-0.3%
MO	-0.9%	-4.3%	-0.4%	-4.6%	-0.5%	-0.8%	-0.8%
MN	1.5%	3.3%	0.8%	3.6%	1.1%	1.6%	2.8%
ND	4.0%	-2.7%	-1.8%	13.6%	1.5%	-0.1%	9.5%
SD	2.3%	6.5%	0.0%	10.3%	-2.7%	1.0%	-9.6%
WI	1.4%	4.1%	0.1%	3.7%	1.0%	0.8%	2.7%
S. Central	**0.6%**	**-0.3%**	**0.3%**	**0.5%**	**0.5%**	**0.2%**	**1.2%**
KS	2.2%	-2.8%	1.6%	6.4%	1.0%	1.1%	3.9%
NE	3.4%	-2.6%	1.0%	-1.8%	2.7%	1.3%	1.8%
OK	2.0%	1.7%	0.0%	0.7%	0.8%	1.1%	0.0%
TX	0.0%	-0.2%	0.2%	0.2%	0.3%	-0.1%	1.1%

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