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Assessing the Final Clean Power Plan
Energy Market Impacts

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Introduction

The U.S. electricity sector is undergoing a period of rapid change. The U.S. Environmental Protection Agency's Clean Power Plan (CPP), regulating carbon dioxide (CO_2) from existing power plants, is a significant—but by no means the only—catalyst for the transitions underway in the sector. In the third and final note in our series on the CPP, we explore the energy market outcomes of the rule under two scenarios and discuss what factors could change the magnitude of these impacts.[1] As we have previously noted and explain in more detail below, projecting actual energy market outcomes is made challenging by the flexibility states have in implementing the rule, by the uncertainty facing the CPP as a result of the legal process now underway, and by the nonregulatory factors also influencing energy markets.[2]

Key messages of this paper include:

- The CPP, enhanced by the tax extenders passed in December 2015, will drive a shift in the U.S. generation mix away from coal and toward renewables.[3] The magnitude of the shift depends on a variety of factors, but the decisions state regulators take will exert significant influence on the future energy mix.

- The two most consequential decisions state regulators take in this regard are 1) the choice of a rate- or mass-based implementation plan; and 2) additional decisions under a mass-based plan, including how to distribute allowance value and whether (and how) to cover new power plants. These decisions will impact the incentives generators face and will

[1] Our other notes explore the differences between the draft and final rule and the emissions outcomes of the final rule. See John Larsen et al., "Assessing the Final Clean Power Plan: Key Changes Relative to the Draft Rule and Their Implications for Stringency," Center for Strategic and International Studies and Rhodium Group, October 2015, http://csis.org/files/publication/151001_Larsen_AssessingCleanPowerPlan_Web.pdf; and John Larsen et al., "Assessing the Final Clean Power Plan: Emissions Outcomes," Center for Strategic and International Studies and Rhodium Group, January 2016, http://csis.org/files/publication/160106_Larsen_AssessingCleanPowerPlan2_Web.pdf.
[2] For more on the legal process and what it means for energy markets, see John Larsen et al., "Implications of the Supreme Court Decision to Stay the Clean Power Plan," Center for Strategic and International Studies, February 2016, http://csis.org/publication/implications-supreme-court-decision-stay-clean-power-plan.
[3] John Larsen and Whitney Herndon, "Renewable Tax Extenders: The Bridge to the Clean Power Plan," Rhodium Group, January 2016, http://rhg.com/notes/renewable-tax-extenders-the-bridge-to-the-clean-power-plan.

influence new capacity additions, dispatch shifts, and ratepayer impacts. Regardless of plan type, however, emissions outcomes would be roughly the same.

- Natural gas prices and production are largely unmoved by the CPP, although high renewables deployment could put slight downward pressure on prices. More aggressive assumptions about cost declines for natural gas or renewables could result in higher deployment of these fuels.

- Electricity bills rise in both scenarios we modeled, but rise higher under a mass-based scenario. Under a mass-based plan, the impact of electricity bill increases could be mitigated or offset by directing allowance value to consumer rate relief.

While both rate- and mass-based plans have a roughly equivalent impact on overall CO_2 emissions, as we explored in our second note, they differ markedly when it comes to their impact on energy markets.[4] The difference in energy market outcomes is the product of different incentives for generators under rate- and mass-based plans, which in turn results in different abatement costs under the two scenarios. As a consequence, in selecting a plan type, states will have a considerable influence on ratepayer impacts, generation mix, and many other energy market dynamics. Of course, the choice to pursue a mass- or rate-based plan will be informed by a variety of factors, only one of which is the impact on a state's energy sector.[5]

Rate vs Mass: Design Choices Impact the Electricity Market

The purpose of the CPP is to reduce greenhouse gas emissions by shifting the power sector toward lower-emitting sources of generation. Currently, generators across most of the country are dispatched on the basis of their cost. Regardless of plan type, the CPP shifts dispatch by changing the cost of generation for different types of power plants. Under both rate- and mass-based options, zero and low-emissions generators will have an incentive to run more than they would without the CPP. The difference is how those incentives are structured and conveyed in electricity markets. All of the energy market impacts we discuss below follow from this basic fact.

In a rate-based plan, each generator must meet an emission standard expressed in pounds of CO_2 emitted per megawatt hour of electricity produced (lbs/MWh). Any covered generator with an emission rate higher than the standard set by EPA (such as a coal plant) faces a new cost in the form of "Emission Rate Credits" or ERCs (denominated in MWhs) that they must hold in sufficient quantities to bring their compliance emissions rate down to the standard. They obtain these ERCs from eligible sources, which are the only entities that can create ERCs. Any generator with an emissions rate below the standard receives new revenue by producing and selling ERCs to plants with emissions rates over the allowable limit. Eligible sources therefore create and sell ERCs, either to generators who need them or to third parties that will resell them. The vast majority of

[4] For an analysis of how plan choice impacts emissions, see our second note: Larsen et al., "Assessing the Final Clean Power Plan: Emissions Outcomes."

[5] Other factors state regulators may consider in whether to select a rate- or mass-based option include the administrative burden of selecting a particular plan type and how their choice of plan may impact their ability to buy or sell credits beyond their state, as rate states may only trade with other rate states, and likewise mass states may only trade with other mass states.

ERCs are going to be generated by new zero-emitting sources, such as wind, solar, and nuclear.[6] The value of the ERC—which can be sold to units that are above the rate standard and must hold ERCs to be in compliance—therefore is realized primarily by the owners of zero-emitting generation. This gives an economic boost to these sources, while imposing a cost to generators who must hold ERCs. In that way, value is transferred from generators that don't meet the standard to generators that exceed the standard. Under a rate-based plan, regulators have no control over how credit value is used because the specifics are built into the standard itself. Choosing the rate-based path means regulators are foregoing the opportunity to use compliance credit value for more targeted policy purposes.

Under a mass-based plan, by contrast, each state has a total allowable amount of tons of CO_2 it can emit from the power sector. All covered fossil generators—not just a subset who fail to meet a certain rate—must hold allowances to cover all of their emissions. All fossil generators therefore see a new cost as they must hold allowances for every short ton of CO_2 they emit; the higher a generator's emissions, the higher the cost they must pay. The state creates "allowances" to represent each ton allowed (for example, if the target is 1,000 tons of CO_2, there would be 1,000 allowances). Zero-emitting generators do not have to hold allowances, but they also do not create allowances. Low- and zero-emission generators have a competitive advantage since they do not have any new cost to achieve CPP compliance, in the case of zero-emitting generation, and do not see the full cost, or have relatively lower costs compared to coal plants, in the case of lower-emitting generation.

Because the state creates these allowances in a mass-based plan, it is state regulators that decide how to distribute them—and therefore the regulators have more control over what happens to the value of the allowance, and a limited but important ability to influence energy market outcomes.[7] Regulators can auction some or all of the allowances and direct the revenues to compensate ratepayers or generators (assuming that they have authority from the legislature in their state to do so), can give allowances to specific generators based on a variety of criteria, or can distribute allowances based on a combination of auction and free distribution.

Modeling Results

To assess the emissions outcome of the CPP on energy markets, we considered two CPP policy scenarios (as well as a reference scenario for comparison) using the same approach as in our previous note.[8] We model these scenarios in RHG-NEMS, a version of the National Energy Modeling System used by the U.S. Energy Information Administration (EIA). The reference case is keyed to EIA's Annual Energy Outlook 2015 and includes all major energy and environmental policies except for the CPP. Since our last note, we have updated all three of our scenarios to account for Congress's December 2015 extension of key renewable energy tax credits. Our two

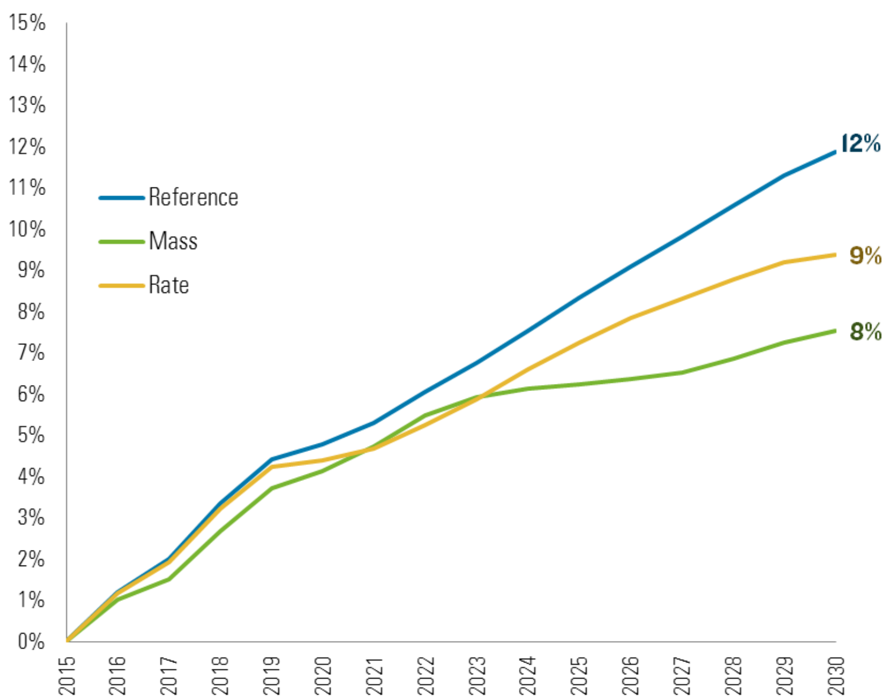
[6] Under the CPP, EPA only allows ERCs to be generated from eligible zero-emitting resources built after 2012 and existing fossil generators that beat the applicable emission rate standard.
[7] If state regulators decide to cover existing sources only, they may be required to adopt a prescribed allowance distribution approach to mitigate potential leakage as required by EPA. Covering both new and existing sources frees states to choose whatever allowance distribution approach they prefer.
[8] See Larsen et al., "Assessing the Final Clean Power Plan: Emissions Outcomes.".

CPP scenarios represent uniform, nationwide implementation of 1) a rate-based tradable performance standard covering existing fossil generators (Rate); and 2) a mass-based emissions standard covering both existing and new fossil generators (Mass). The technical appendix contains more information on our modeling approach as well as detailed descriptions of each scenario.

Consumer Impacts

Our analysis demonstrates how the differences in incentives for generators under rate- or mass-based plans impact the power sector. With or without the CPP, electricity demand rises in all scenarios compared to current levels; however, both CPP scenarios result in lower demand growth compared with the reference case (see Figure 1).

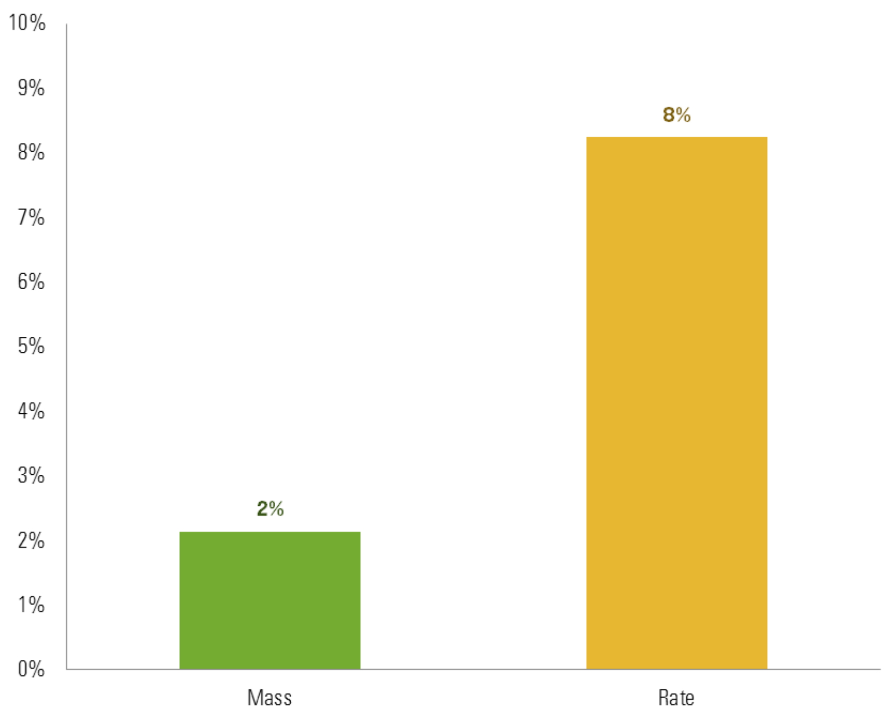
Figure 1. National electricity sales (% change from 2015)



This reduces the need for new generating capacity (see below). The reason demand is lower in both Rate and Mass scenarios is that the CPP increases electricity rates, causing consumers to reduce consumption. However, this price impact varies by scenario. In the Mass scenario, which assumes that all allowances are auctioned, fossil generator costs go up, reflecting the cost of allowances, but the costs for all other generators stay the same. The net effect is to put upward pressure on wholesale power prices and in turn electricity bills unless allowance value is redistributed in some way to assist ratepayers. In the Rate scenario the value of ERCs is simply transferred from one set of generators to another. While fossil generator costs go up, ERC eligible generator costs go down due to their new ERC revenue stream dampening rate impacts. Because consumers do not see as much of a price impact in the Rate scenario, we do not see demand impacted as much as in the Mass scenario. This explains the substantial difference in consumer bills under the two options. National electricity expenditures in the Mass scenario are about 11 percent higher in 2030 compared with the reference case, and 1.1 percent higher in the Rate scenario.[9] We would expect there to be regional variation that is not reflected by these national averages.

In spite of the difference in consumer bills between Rate and Mass, the overall system costs (costs of fuel, capacity, maintenance, transmission, etc.) are actually higher in the Rate scenario. Relative to the reference scenario, the Mass scenario total system costs rise by 2 percent annually, on average, throughout the CPP compliance period (Figure 2). In the Rate scenario, though, costs rise by 8 percent. As we explain in detail below, the incentives to generators in the Mass scenario allow existing capacity (especially natural gas combined cycle generation units, or NGCCs) to contribute more toward compliance with the CPP. This is in contrast to the Rate scenario, where a large wave of new renewables and to a lesser extent nuclear is built to comply with the CPP. The costs associated with the huge increase in new capacity in the Rate scenario outweigh the increase in costs for fuel associated with more gas generation in the Mass scenario.

Figure 2. Cumulative change in electric power total system costs, 2022–2030 (% difference from reference case)



[9] Expenditure values for the Mass scenario assume that no allowance value is returned to consumers to mitigate rate impacts.

Electricity Market Impacts

In our previous note, we found that the choice of a rate- or mass-based plan makes little difference for emissions outcomes under optimal implementation; when it comes to energy markets, by contrast, our Rate and Mass scenarios lead to considerably divergent outcomes. This is largely due to differences in how EPA designed the rate- and mass-based plan options. Under a rate-based plan, only generation built after 2012 can generate ERCs. Because existing nuclear and renewables do not receive ERCs, there is a difference in relative incentives for zero-carbon generators. As a result, we would expect to see a large build-out of new renewables relative to a mass-based plan. Under a mass-based plan, however, there is no automatic revenue stream for generators of any kind, and therefore this eligibility distinction does not come into play.[10] We find that the different incentives provided to generators under rate- and mass-based plans and associated consumer demand responses have a major impact on the future U.S. generation mix.

First, the Rate and Mass-based scenarios differ in terms of the amount of capacity additions. A key factor driving capacity additions is consumer demand. Lower demand in the Mass scenarios leads to fewer capacity additions compared to the Rate scenario relative to 2015 capacity (see Figure 3). Regardless, both CPP scenarios lead to greater capacity additions than under the reference case because new capacity is required to fill in behind coal plants that retire due to increased costs of compliance that come with implementation of the CPP.

Second, in both the Mass and Rate scenarios, utility-scale wind and solar make up the lion's share of new additions as a result of the incentives for zero-emitting generation described above. In the Rate scenario, nearly all of the capacity additions (195 GW by 2030) are wind and solar, accompanied by 19 GW of new nuclear and almost no NGCC additions. By contrast, in the Mass scenario, renewables account for 109 GW of new capacity by 2030, 31 GW of NGCC is also added—roughly the same amount of natural gas as is built in our reference case. This is a result of the fact that, even with the cost of allowances, new gas remains competitive with renewables. Meanwhile, we see 70 GW of coal retirements in the Mass scenario by 2030. That's nearly double the 37 GWs in our reference case and slightly more than the 62 GW that retire in our Rate scenario. The difference is again a reflection of the different incentives between the two plan types. The cost of allowances in the Mass-based scenario makes coal slightly less competitive to all other capacity types than the cost of ERCs does in the Rate-based scenario.

[10] An important caveat is that if states choose a mass-based plan but opt to cover just existing sources, new NGCCs will receive a greater incentive to run relative to other fossil generators. This could result in emissions leakage as discussed in our previous note. It could also influence shifts in generation under the CPP away from zero-emitting sources. Both outcomes are also influenced by the design and effectiveness of any leakage mitigation requirements EPA includes in the final CPP model rule and Federal Plan.

Figure 3. Cumulative capacity additions change from 2015 (GWs)

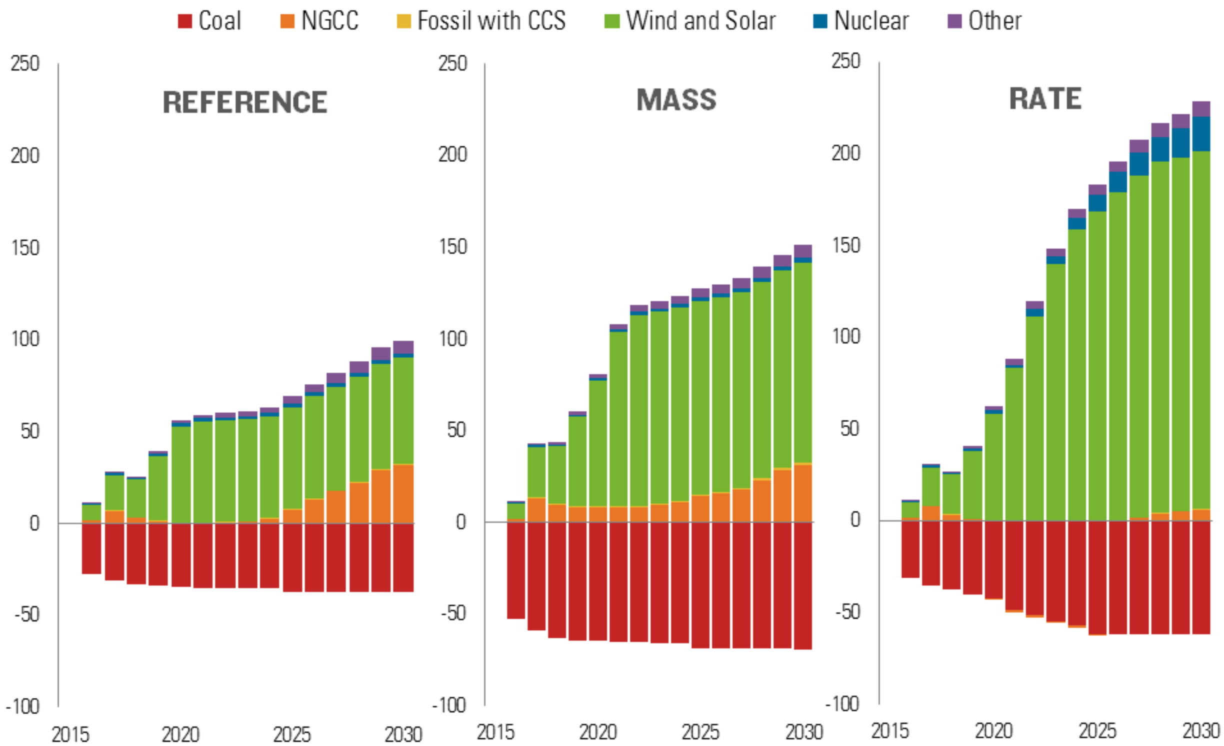
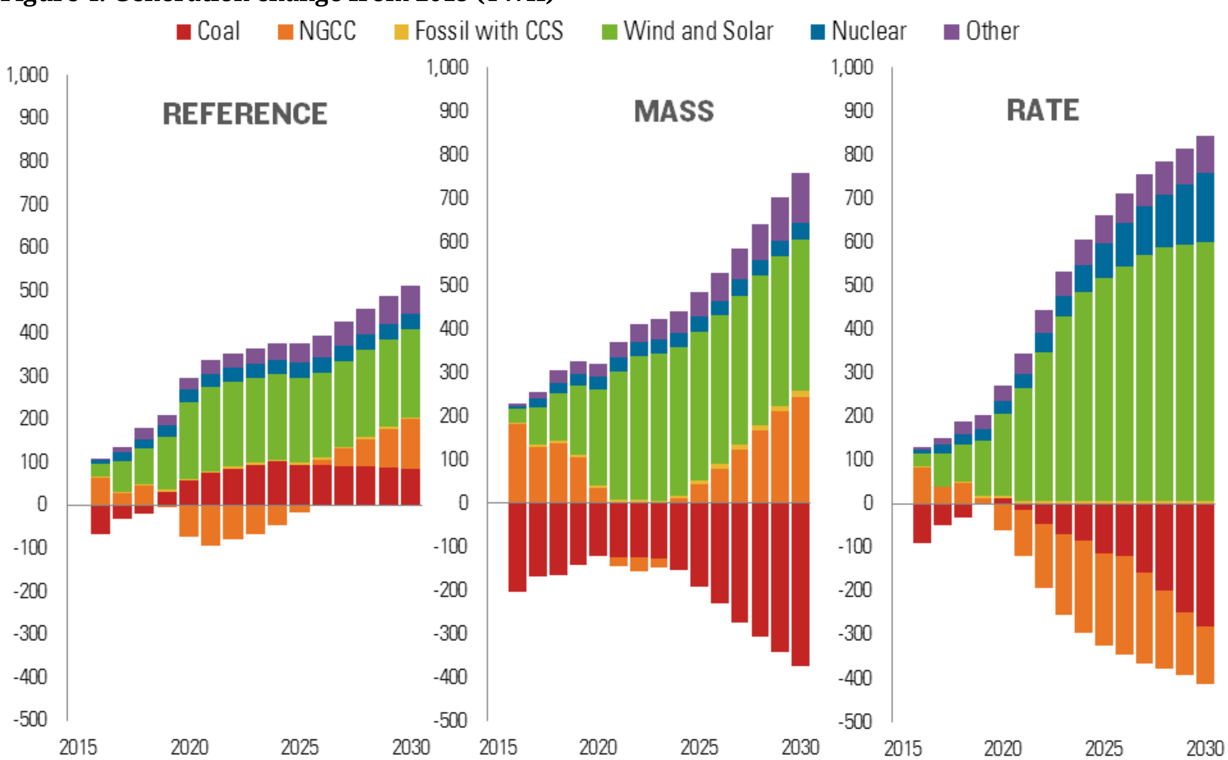


Figure 4. Generation change from 2015 (TWH)



Third, as might be expected, the CPP also shifts the national generation mix in different ways depending on the scenario. In our reference scenario, utility-scale wind and solar see the largest gain in generation (thanks to the tax extenders) compared to 2015, followed by a small rebound in coal generation. Wind and solar also see the largest gains in our Mass and Rate scenarios, but as with the capacity additions, to different degrees (see Figure 4). Under the Mass scenario, wind and solar generation increase by nearly 350 TWh compared to 2015 levels by 2030—a 70 percent increase over the reference scenario. Meanwhile, in the Rate scenario wind and solar generation increase by 595 TWH over 2015 levels by 2030, a 192 percent increase over the reference scenario. Nuclear also sees a boost in the Rate scenario while it's little changed in the Mass and reference scenarios. Where fossil generation increases in the reference scenario, it declines on net in both CPP scenarios but in different ways, again reflecting different incentives to generators. In the Mass scenario, NGCC generation increases over the compliance period, while coal declines by 375 TWH, about 25 percent of 2015 levels. In the Rate scenario, both coal and NGCC generation decline by 280 TWH and 135 TWH, respectively, by 2030.

State Choices Matter, and so Do Independent Developments

Our analysis demonstrates that the fundamental choice of a rate- versus a mass-based compliance program can have dramatic impacts on the contours of the future energy market. However, there are several factors not captured by our scenarios that could result in differences in energy market outcomes than what we have outlined above. Below we discuss areas of uncertainty both within and beyond state control, all of which will have an impact on the energy mix and consumer impact (and emissions) to 2030:

1) *Different allowance distribution choices in a mass-based program.* In our Mass scenario we assume that states auction 100 percent of their allowances. However, if a state were to distribute some or all of the allowances using some other method, we would expect the energy market impacts could differ from what we have presented here. How different would depend on a variety of factors, including what proportion of the allowances is auctioned, which entities receive the allowances, and what allowance distribution methodology is used. There are myriad possible outcomes that could result from different distribution choices. For example, allowances can be distributed to all generators within a state (including zero-emitting generators), solely to regulated sources, to load-serving entities, or to non-power producing entities, among others.[11] The key consideration is that allowances have a market value—any deviation from auctioning will shift value from ratepayers who pay for the cost of allowances passed through in rates to allowance recipients instead of to the government.

   Free distribution of allowances to generators may not result in ratepayer relief in many instances and instead shifts allowance value away from ratepayers to generators. Generators in competitive electricity markets are dispatched based on their cost of generation. If allowances are given to generators or some subset of generators for free, the

[11] For more detail on different options for allowance allocation, see Franz Litz and Brian Murray, "Mass-Based Trading under the Clean Power Plan: Options for Allowance Allocation," Nicholas Institute for Environmental Policy Solutions and Great Plains Institute, Working Paper 16-04, March 2016.

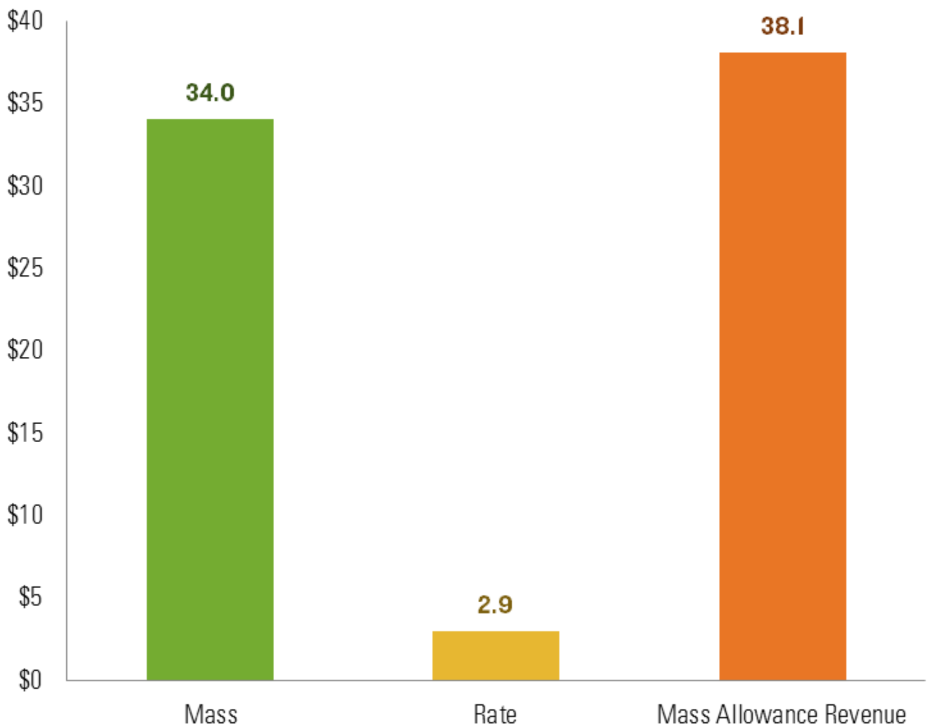
recipients receive the value of those allowances but there is no requirement that that value must be passed on to consumers. Indeed, recipient generators are free to sell those allowances at any time and collect revenue from the sale. This opportunity cost of not selling the allowances is included in a generator's bid price and (assuming competitive and liquid allowance markets) should equal the market price for allowances and/or the price the generator would have paid under an auction.

Thus in competitive markets ratepayers should see the same rate impacts under free distribution to generators as under and auction. This is not necessarily the case in rate-regulated markets where state public utility commissions (PUCs) can require recipient generators pass the value of free allowances on to consumers, mitigating rate impacts to some extent. This explains why the northeast states participating in the Regional Greenhouse Gas Initiative (RGGI states) have largely opted for auctions since most of these states have competitive wholesale electric markets. An alternative approach would be to distribute allowances to load serving entities that are under the oversight of state PUCs allowing regulators to require that allowance value be used for the benefit of ratepayers. Different methodologies for distributing allowances freely to generators determines how much allowance value each generator gets and may shift capacity retirement and new build decisions depending on the approach chosen. The choice between free allowances to generators or auctions primarily influences who receives the benefit of allowance value but does not change consumer impacts unless (as discussed below) allowances value is directed specifically for that purpose.

2) *How states distribute the revenues from auctioning allowances.* If states choose to go with a mass-based plan and auction allowances, they have an important new revenue stream at their disposal. How they choose to use it could ease the transition to the CPP and could also have important implications for the energy system. In our Mass scenario we assume that states do not use the value of the revenue from auctioning allowances for a specific policy purpose. States have several options for how to use revenue from allowance auctions, including using the revenue to 1) compensate consumers for higher electricity costs; 2) compensate generators for lost production and/or reduce compliance costs; 3) invest in further energy sector transformation, such as energy efficiency; 4) cover nonenergy-related state expenditures such as closing budget gaps; 5) provide transition assistance to displaced workers and industries and/or low-income consumers; 6) implement a combination of any of these options. For example, were a state to return the auction value to the consumer to moderate the price impact, we would expect higher electric demand than we have presented here (dependent on how the value is returned to the consumer; an automatic utility bill credit would likely have a greater impact on energy demand than an off-bill lump sum check). By contrast, investing at least a portion of the revenues in energy efficiency (as in the RGGI states) may further reduce demand and consumer bills. In addition, states could use their auction revenue to compensate customers that are disproportionately impacted by the program (such as trade-exposed, energy-intensive industries or low-income consumers). The option for revenue distribution that is least likely to result in divergences from what we present here is if states add the revenue for their general operating budgets.

Figure 5 provides one example of how this could play out. Total national average electricity expenditures in our reference scenario are $445 billion per year between 2022 and 2030. The Mass scenario adds another $34 billion or 8 percent in annual average costs before considering any allowance value funded consumer assistance. The Rate scenario increases average annual costs by $2.9 billion. Meanwhile, national average allowance revenues from auctions in the Mass scenario total $38.1 billion per year. Allowance value provides regulators with the option of completely offsetting the cost of the CPP relative to reference through ratepayer assistance with allowance value to spare. Of course, each state's specific situation with regard to allowance revenue and bill impacts will be different but this national aggregate example provides one demonstration of how allowance value can be used under the CPP.

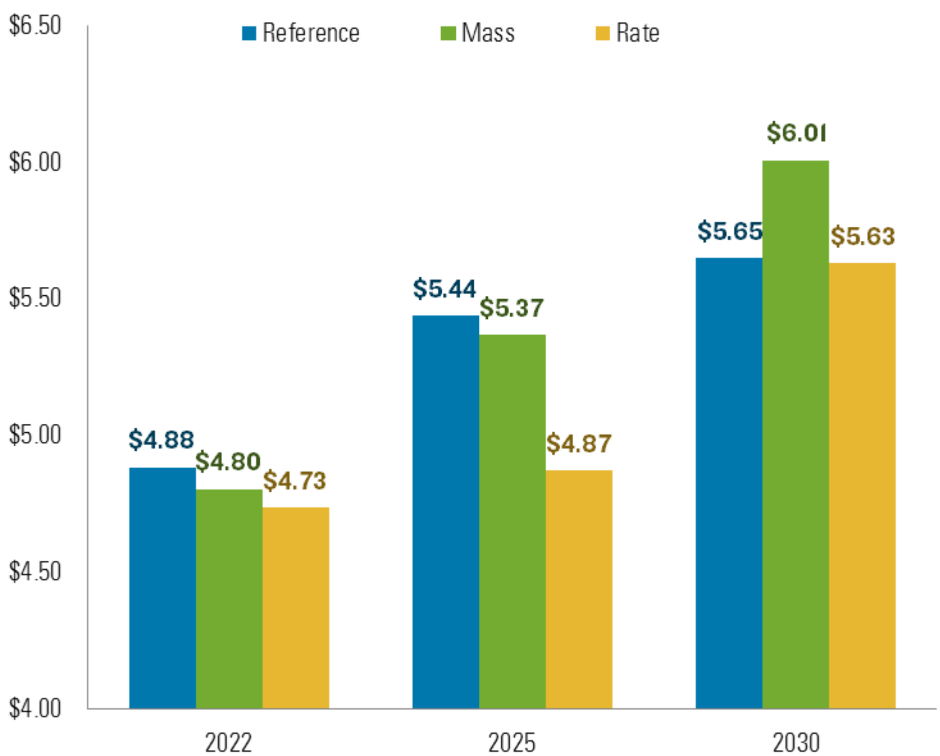
Figure 5. National average annual electric expenditure change from reference and allowance revenue, 2022–2030 (billion 2013 USD)



3) *Fuel prices and technology costs.* Differences in prices across fossil fuels can also change incentives for power generators just as the CPP can. Our scenarios rely on EIA's Annual Energy Outlook 2015 reference case assumptions for fossil fuel resources and prices as well as renewable technology costs. If real-world energy markets produce different fuel prices than assumed in our analysis, we would expect different results than what we present here. This is true with regard to fuel costs for both fossil fuels and renewables. With regard to the former, our modeling shows that the impact of the CPP on fossil fuel markets is fairly modest for natural gas and substantial for coal.

When looking at national benchmark Henry Hub natural gas prices, there is little difference in prices between the two CPP scenarios at the beginning of the compliance period (Figure 6). As the CPP ratchets downward in stringency over the course of the compliance period, gas prices see a small increase in the Mass scenario and slight decrease in the Rate scenario relative to reference. By 2030, gas prices are 6 percent higher in the Mass scenario and 0.4 percent lower in the Rate scenario compared to the reference scenario. This reflects the different roles the NGCC generation play under each pathway as discussed above.

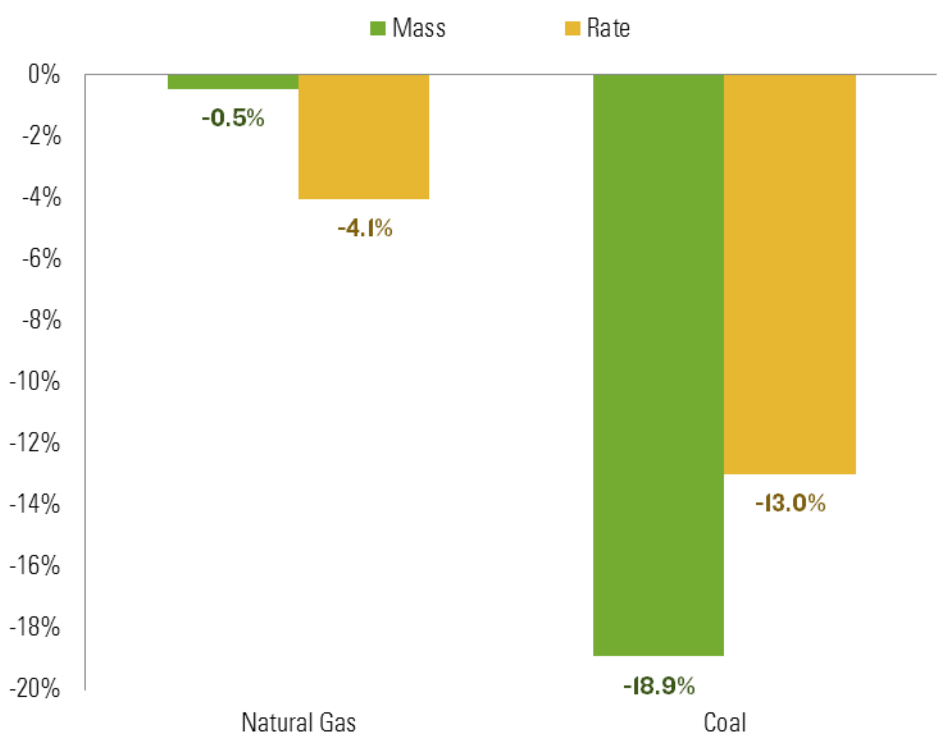
Figure 6. Henry Hub natural gas prices in select years (2013 USD/mmbtu)



Somewhat lower gas prices in the Rate scenario lead to national natural gas production that is 4 percent lower on an annual average bases over the compliance period than in the reference scenario (Figure 7). Meanwhile production is little changed in the Mass scenario. The story for coal is very different. Coal production declines on an average annual basis relative to the reference scenario by 19 and 13 percent for Mass and Rate, respectively.

However, if the costs of natural gas are lower than we assume, we would expect to see greater NGCC generation and potentially less renewables in each of our CPP scenarios all else equal. If the cost of new wind and solar capacity ends up lower than what was assumed in this analysis, these resources might play an even larger role in the energy mix. If states implement additional energy efficiency programs (potentially funded by allowance auction revenues), lower electric demand could reduce the level of new renewables deployment seen in both of our CPP scenarios. It is not only absolute price level that matters in this context; volatility matters as well. We present a stable, national fuel price projection, while historically natural gas prices have not been stable over long periods of time, and vary considerably by region. While we are currently in a period of low volatility for natural gas prices, there are differing opinions about whether this low volatility is a temporary or permanent fixture of natural gas markets. The perception of potential future volatility of natural gas prices may impact state and utility decisionmaking about what resources to pursue, which is likely to vary according not only to views on the future of natural gas prices, but market structure as well. For example, in the vertically integrated states in the Southeast, new nuclear may be an attractive alternative to natural gas. In restructured wholesale markets, however, the options available to policymakers and generators are different and they may pursue other options to hedge against the potential volatility of natural gas prices.

Figure 7. Average annual change in national fossil fuel production, 2022–2030 (percent change from reference)



4) *Economic growth.* Broader assumptions about the rate of economic growth can also influence the energy sector impacts we present here. Faster economic growth typically leads to greater electricity demand and slower growth or a recession could lead to declines in demand. Different electric demand pathways will influence what new generation gets built and how generation may shift under different CPP pathways.

5) *Federal and state policy.* The shape of federal policy—including the ultimate fate of the CPP—will also impact ultimate energy sector outcomes to 2030. If the CPP is upheld but significantly delayed in implementation, we would expect to see different outcomes than what we have presented here. For example, if the courts uphold the CPP in its entirety but the start of the compliance period is delayed by a year or two, we would expect changes in capacity and dispatch to be delayed to some degree. If the CPP is upheld but stringency is relaxed because one or more components of EPA's Best System of Emission Reduction are struck down, we would expect to see much more modest power sector changes under both CPP scenarios compared to reference.

   The future of federal tax policy will also matter. For example, the tax package passed in December 2015 that extends and then phases out renewable energy tax credits through 2021 could be renewed again. Beyond CPP implementation plan decisions, state revisions and expansions of renewable portfolio standards and energy efficiency programs could boost renewables and reduce demand respectively. In aggregate, these policies could shift our results and potentially lead to greater deployment of renewables than what we present here.

6) *State CPP implementation choices.* In this analysis we assume nationwide uniform implementation of a mass or rate standard. Just as rate- and mass-based plans set different incentives for generators, if states choose different plan types than their neighbors, generators in some states may face very different incentives than generators in neighboring states. This patchwork implementation could lead to different pathways for capacity additions and generation shifts and associated consumer impacts and system costs. As an illustration, imagine two states in the same power market. One state implements a rate-based plan and the other implements a mass-based plan. Since both states trade power with one another, generators in the rate-based state will be directly influenced not just by the incentives from that state's plan but also indirectly by the incentives from the mass-based plan in the other state. In this scenario a new wind farm in the rate-based state would receive revenue from the production and sale of ERCs while an identical windfarm in the mass-based state would not. This could lead to greater deployment of wind in the rate-based state than if both states operated under a rate-based plan.

   State choices regarding compliance credit trading could also change our results. We assume nationwide trading in both CPP scenarios. This allows a generator to take advantage of all eligible compliance options throughout the country within the constraints of a plan type. If states choose to band together in smaller groups or not trade at all, they will have a smaller and less diverse compliance market to rely on. While it is difficult to provide directional guidance on how these choices may shift, our results show that such shifts are likely to be small in aggregate but could be substantial from state to state. Combining these choices with the potential impacts from patchwork implementation, we could see substantially different power market outcomes in some states. Large deviations from our optimal scenarios will likely lead to larger ratepayer impacts and system costs on a national basis, though some states may be better off depending on the pathways they choose.

7) *Coverage of existing sources only and emissions leakage.* In our last note, we highlighted the importance of emissions leakage that could result due to shifts in generation from covered sources to uncovered sources in the context of projecting emissions outcomes. Under the CPP, states are required to regulate existing fossil sources, but coverage of new fossil sources is optional. Decisions that states make with regard to CPP coverage and leakage mitigation could also impact energy markets by changing incentives for generators. Under a mass-based plan on existing sources only, existing sources see a cost in the form of allowances while new sources do not. In effect, new NGCC units see the same incentives to run as zero-emitting generators, allowing them to outcompete both covered generation and in some cases zero-emitting generation resulting in higher emissions and higher NGCC generation than if all fossil sources are covered. If intrastate or interstate leakage produces incentives for increases in generation from new NGCC plants, we expect to see these plants play a bigger role in the energy mix compared to what we report here. Any increases in NGCC generation due to leakage would almost certainly come at the expense of renewables. The magnitude of additional NGCC generation will depend on how many states opt to cover new NGCC generators and the effectiveness of any leakage mitigation measures EPA may require of states as they develop state plans.

Appendix: Modeling Approach

For both Rate and Mass scenarios we assume optimal implementation of the standards (see Table 1). This means we assume that implementation is not delayed by legal processes and all states submit state implementation plans (SIPs) on time, all SIPs meet EPA's approvability requirements, and all state standards are applied in 2022 at the start of EPA's mandated compliance period. Both the Rate and Mass targets follow EPA's glide path targets from 2022 through 2030 and are flat after that. We also assume complete and unrestricted compliance credit trading between all states. In the Mass scenario, we assume all allowances are auctioned and revenues are not redirected for any policy purpose. Auctioning was chosen as the method of allowance distribution for this analysis because of its prevalence in existing state mass-based programs and because it is the most economically efficient method available to states. Our approach allows for an assessment of the initial impacts of the standard and can inform how allowance value might be used. Given the broader complexity of SIP design, and the additional constraints regarding allowance distribution imposed by a mass cap on existing units only, states may find it attractive to choose either a rate-based approach or mass-based standard on new and existing sources. We have selected to model these two pathways because they represent the two fastest SIP approval tracks provided by EPA under the CPP final rule. Neither option contains additional requirements for states to include leakage mitigation measures such as adoption prescribed allowance distribution approaches.

Targets for each scenario are derived from EPA's CPP Final Rule. Specific annual targets are included in Table 2.

Table 1. Scenarios Analyzed

Policy Scenario	Description of Standard	Source Coverage	Trading	Credit Distribution	EPA Leakage Mitigation Option Utilized
Mass	Single national mass-based standard	New and existing fossil generators subject to 111d	Nationwide, unrestricted trading	100% Auction	Cap on new and existing sources
Rate	Single, uniform national emission rate standard	Existing fossil generators subject to 111d	Nationwide, unrestricted trading	To eligible resources (existing NGCCs, incremental zero-emitting generation and incremental demand-side efficiency) based on generation/savings	No mitigation required

Source: CSIS and RHG.

Table 2: National Goals Used in Modeling Scenarios

Scenario	Standard units	2022	2023	2024	2025	2026	2027	2028	2029	2030 and beyond
Rate	lbs./MWh	1,405	1,360	1,298	1,263	1,228	1,192	1,159	1,125	1,092
Mass	Million metric tons	1,858	1,804	1,739	1,710	1,678	1,643	1,615	1,585	1,551

Source: CSIS and RHG.

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