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The Importance of Consistency in the Stringency and the Flexibility of the Clean Power Plan

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Insights

In determining emissions performance standards under the Clean Power Plan (CPP), the US Environmental Protection Agency (EPA) considered the possibility for increased generation from non-emitting facilities as one way to reduce emissions, and this possibility is reflected in the stringency of the standards. A part of the pending legal challenge is the claim that EPA lacks authority to consider activities beyond those that can be taken at the affected facilities, that is, existing coal and gas-fired plants. Our modeling exercise illustrates the importance of consistency in the options EPA can consider in setting the targets and the options that can be used for compliance.

The stringency of emissions rate policies is ambiguous when unanticipated flexibility is introduced. For example, a specific emissions rate improvement averaged over a larger set of generators may lower cost but also reduce the actual emissions change; if averaged over a smaller set of generators the cost may be greater and the emissions change may be greater. We find that:

- If EPA were to restrict compliance options to measures that could be taken at affected facilities while keeping the emission rate standards the same as under the CPP, total power sector emissions would be substantially lower than anticipated under the CPP; however costs would be greater.
- If the agency were required to revise the regulation so that standards were not based in part on opportunities beyond the affected facilities, EPA might adopt more lenient emission rate limits that could achieve emissions outcomes similar to the CPP at lower cost compared to the set of scenarios we model. However, the costs may be greater than under the CPP.

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- It is likely that more lenient emission limits would still trigger substantial changes to the power sector, including more coal plant retirements and increased use of natural gas, wind, and solar power.

Overview

The CPP is a centerpiece of US climate policy and is expected to reduce emissions from the electricity sector by 34 percent by 2030. The CPP is now under review by the DC Circuit Court, and its implementation has been stayed (frozen) by the US Supreme Court pending completion of court review. Arguments on the merits are scheduled to be heard by the Circuit Court in June 2016.

The CPP introduces carbon dioxide (CO_2) emissions performance standards (lbs/MWh) for the subcategories of existing steam (usually coal-fired) units and natural gas combined cycle (NGCC) units. States are responsible for developing plans indicating how existing electric generating units (EGUs) will achieve the standards. The CPP gives states the option of implementing a rate-based limit (lbs/MWh) or a mass-based (tons) equivalent and allows emissions rate averaging or emissions allowance trading over the interim period (2022-2029) among units within a state. With EPA approval, EGUs may average emissions rates or trade emissions allowances across state borders. However, units in states choosing a rate-based approach may not trade with units in states choosing a mass-based approach. EPA's rule does not require coverage of new sources under these provisions, but states may decide to do so.

The emissions performance standards are based on EPA findings of adequately demonstrated technology for achieving emissions reductions. Variation in emissions rates at existing coal-fired power plants provides one measure of opportunity to reduce emissions and variation in the utilization of natural gas units and the opportunity to substitute from coal to gas provides another. EPA also has looked across states to identify adequately demonstrated opportunities for renewable energy. The standards also can be achieved through expanded utilization of biomass, nuclear, carbon capture and storage, or energy efficiency. The CPP does not impose specific technology requirements on EGUs and goals can be achieved through trading within or across states. No specific investment or operational change is required at an EGU at any point in time.

EPA justified its regulatory design by interpreting the statutory requirement to implement the "best system of emission reduction" to encompass measures or operational changes taken at one facility that will have inevitable effects on the operation of other facilities and the entire system through the inter-connected power grid. A central part of the legal challenge to the EPA is the assertion that the agency does not have authority to consider activities beyond those that can be taken at the affected EGUs, that is, existing coal- and gas-fired plants. This argument has two dimensions. First, it suggests that EPA cannot base the stringency of the regulation on opportunities to expand the utilization of other facilities. Second, it suggests EPA cannot allow flexible compliance that gives

credit for actions taken away from the affected EGUs.

This brief describes a modeling exercise to investigate the consequences of basing emission limits only on actions that can be taken at affected EGUs. In the preamble to the CPP, EPA identifies actions that can be taken at these plants (such as co-firing with biomass or natural gas at existing coal-fired plants or carbon capture and storage) that EPA did not consider in determining the adopted emissions performance standards. EPA did not base the standards on these possible actions because they are more costly than other options (such as investments in renewable energy and energy efficiency) that in practice would result in a similar emissions outcome. In this analysis, we do not allow the affected EGUs to receive credit for renewable energy and energy efficiency, although such investments might occur in the modeled market equilibrium. We do allow the affected EGUs to pursue co-firing with biomass or natural gas as a way to achieve compliance. In addition, we allow for investments in heat rate improvements at coal-fired plants. We preserve the flexibility of changing the utilization of plants and of emissions rate averaging (trading) among all affected EGUs (coal units only in case 1; coal and gas units in the other two cases) to achieve the emissions performance standard.

This modeling exercise examines several scenarios in which the rate limits for coal- and gas-fired units are applied to affected units exactly as finalized under the CPP, but compliance options and available credits are restricted to measures that could be taken at affected facilities. We note that if such a restricted regulation were applied, the target-setting methodology and corresponding rate limits would likely be adjusted to reflect the changes to the scope of the best system of emissions reductions. However, attempting to adjust the rate limits was beyond the scope of this exercise. Instead, this preliminary analysis examined the application of the rate limits as finalized in the CPP under three different restricted scenarios in order to determine the directional changes to power sector compliance, as compared to a compliance scenario in which the full flexibility of the CPP is utilized.

The purpose of the exercise is to see whether EPA can achieve equivalent emissions reductions if emission rate limits and compliance options were restricted to measures that could be taken at the affected EGUs. We consider four policy scenarios. In one case, we assume an emissions rate performance standard (lbs/MWh) applied only to coal-fired units. In the second case, we assume dual-rate emissions performance standards for coal and natural gas units. In the third case, we assume a uniform (blended) emissions rate performance standards applied to all generation from affected coal and natural gas units.

In brief, we find the following:

- The CPP's emissions reduction results can be achieved and surpassed. Under all three scenarios sector-wide emissions are below those embodied in the mass-based

targets in the CPP that includes existing and new sources.

- Electricity price increases are greater under all three scenarios compared to our modeling of the approach taken by EPA in determining the best system of emissions reduction.
- There is a substantial shift away from coal-fired generation to natural gas facilities and new renewables.
- There is a small but not substantial increase in co-firing at coal-fired plants.

Power sector CO_2 emissions in this modeling exercise are well below those achieved by the CPP when we model the same numeric emissions performance standards. Alternatively, if EPA were to revise numeric value of the emissions performance standards while restricting compliance to affected EGUs only, it appears the agency could achieve the same or greater emissions reductions as achieved by the CPP. If the agency were required to revise the regulation in this way it might be able to select targets that achieved emissions outcomes similar to the CPP at lower cost compared to the set of inside the fence scenarios we model. However, we suspect the costs might be greater than under the CPP even after the emissions performance standards were revised.

In all cases a significant portion of the emission reductions will occur from other changes in the electricity sector, such as increased use of lower-emitting generation. The CPP anticipated such changes in the program design. If EPA were precluded from considering these changes, the degree of change to the mix of generation in the power sector in general and the overall emissions outcome might be harder to predict.

In previous analysis we have explored the relationship between flexibility and stringency in greenhouse gas regulations, where we found that consistently matching the level of stringency with the degree of flexibility in the regulation can improve cost effectiveness, quadruple the emissions reductions that are achieved for the same cost, and maximize net benefits (Burtraw et al. 2015). This exercise illustrates a related result, that is, the importance of consistency in the options EPA can consider in setting the targets and the options that can be used for compliance.

Scenarios

We present model results from four scenarios.

Coal-Only Performance Standard. This scenario imposes a requirement only on coal-fired power plants equal to the emissions rate goal embodied in the CPP, with an interim (average from 2022-2029) national standard of 1,534 lb CO_2/MWh and a final national standard of 1,305 lb/MWh. Coal plants can make investments to reduce heat rates, co-fire coal units with natural gas or biomass, and trade emissions rate credits among coal plants and increase utilization of the most efficient coal plants. No requirements are imposed on gas-fired units, nor are compliance credits available to coal units from changes at gas units.

Dual Coal and Gas Performance Standards. This scenario adopts both the emissions rate standards for coal plants and an interim national standard for natural gas combined cycle units equal to 832 lb CO_2/MWh and a final national standard for gas of 771 lb CO_2/MWh. Affected coal and gas plants can alter their utilization and average their emissions rates by trading emissions reduction credits so that individual EGUs come into compliance with their fuel-specific standard. Gas shift emissions reduction credits as described in the CPP are available.

Blended Coal and Gas Performance Standard. This scenario imposes a uniform national emissions rate standard for coal and gas plants. The interim standard is 1,235 lb CO_2/MWh and the final standard is 1,078 lb CO_2/MWh. Coal and gas plants can alter their utilization and average their emissions rates by trading emissions reduction credits so that individual EGUs come into compliance with the blended emissions rate.

CPP (New Source Complement). This scenario assumes nationwide coverage of existing and new sources with each state adopting a mass-based policy taking advantage of the new source complement and the mass-based emissions goals taken from the CPP. It assumes national emissions allowance trading and, because it is a mass-based standard, there is flexibility to shift to low- or zero-emitting resources as a compliance pathway, as in the CPP. Emissions allowances are initially distributed according to historic electricity generation shares from among affected units (grandfathering)

Model

We use a highly parameterized electricity market simulation model named Haiku to characterize the response of the electricity system to a variety of potential climate policies undertaken by states and examine the regional interactions of those policies. The Haiku electricity market model[1] is a partial equilibrium model that solves for investment in and operation of the electricity system in 26 linked regions of the continental United States, from 2013 to 2035. Each simulation year is represented by three seasons (spring and fall are combined) and four times of day. For each time block, demand is modeled for three customer classes (residential, industrial, and commercial) in a partial adjustment framework that captures the dynamics of the long-run demand responses to short-run price changes. Supply is represented using 53 model plants in each region, including various types of renewables, nuclear, natural gas, and coal-fired power plants.

[1] Haiku is comparable in sectoral and geographic coverage to the Integrated Planning Model (IPM, owned by ICF consulting and the model of record for EPA), ReEDS (maintained at the National Renewable Energy Laboratory), and the Electricity Market Module of the National Energy Modeling System (NEMS, maintained by the Energy Information Agency). Haiku, IPM, and ReEDS model the electricity sector and partially model factor markets, like fuel, for the continental United States. NEMS also links its electricity sector model to the entire economy and models all fuel markets. For more information about the Haiku electricity market model, see Paul et al. (2009).

Operation of the electricity system (generator dispatch) in the model is based on the minimization of short-run variable costs of generation, and a reserve margin is enforced based on margins used by the Energy Information Administration in the Annual Energy Outlook (AEO) for 2013 (EIA 2013). Investment in new generation capacity and the retirement of existing facilities are determined endogenously[2] for an intertemporally consistent (forward-looking) equilibrium, based on the capacity-related costs of providing service in the present and into the future (going-forward costs) and the discounted value of going-forward revenue streams. Price formation is determined by cost-of-service regulation or by competition in different regions, corresponding to current regulatory practice.

The model includes the capability to co-fire biomass and natural gas at coal-fired plants. Co-firing involves partially substituting another fuel, in this case biomass and/or natural gas, for the usual coal input in the plant's boiler. The co-firing capacity at each coal model plant is subject to several constraints including plant-specific limits on biomass co-firing and capacity investment to enable co-firing. The decision to co-fire is based on the relative costs of different fuels, the cost of converting the existing facilities to use the co-fired fuel, and potentially the benefits of reduced costs for emissions and for credits under an emissions or heat rate performance standard. Biomass may come from a number of categories of waste biomass or from dedicated energy crops, but all of the co-firing that is observed in the model results is waste biomass. Co-firing with biomass is described as having zero CO_2 emissions under the assumption that EPA considers the life-cycle emissions of co-firing with waste biomass to be zero. Biomass co-firing is assumed to have the additional economic benefit of qualifying for a renewable production or investment tax credit or renewable portfolio standard. Co-firing with natural gas is advantaged by assigning it an emissions rate equal to the emissions measured at the stack divided by the heat input. That emissions rate for natural gas used at a plant varies based on the heat rate of the plant, but it is roughly 55 percent of the rate observed for coal-fired generation at the same plant. In general, note that the emissions rate associated with gas co-firing at coal plants is greater than if the gas were used at an NGCC facility. Within Haiku, plants co-fire up to the point where the marginal costs and benefits of co-firing are equal, subject to constraints on the amount of capacity that can co-fire at each plant.

In the model, coal-fired plants also have the opportunity to reduce emissions rates by implementing generation efficiency measures at a cost that grows with the level of the investment. The cost and schedule of opportunities are drawn from econometric estimates in Linn et al. (2014).

All scenarios include the Mercury and Air Toxics Standard (MATS). It does not

[2] Investment (in both generation capacity and pollution controls) and retirement are determined according to cost-minimization.

include the Cross State Air Pollution Rule; instead Title IV and Clean Air Interstate Rule (CAIR) remain in effect for sulfur dioxide and CAIR remains in effect for nitrogen oxides. Detail on the way MATS is modeled and other aspects of the Haiku model are presented in Burtraw et al. (2013).

Results

The model is solved through 2035. We focus our attention on results for 2030. We contrast the results of the three new scenarios with results using the same model of a scenario representing mass-based compliance with the CPP using the new source complement (that is, covering existing and new sources). A summary of the model results is presented in Table 1.

Compared to the CPP new source complement scenario, by 2030 CO_2 emissions fall by half or more when the emissions rates adopted in the CPP are applied without allowing compliance credit for changes in generation due to demand-side efficiency and operation of non-affected facilities such as renewables. This outcome is driven by a substantial reduction in coal-fired generation of 83 – 95 percent. Associated with the reduction in coal generation is a reduction in sulfur dioxide (SO_2) emissions of 82 – 92 percent.

Partially offsetting the reduction in coal generation is a tripling of generation from new wind. Roughly similarly large amounts of new generation come from natural gas; however, under the coal-only performance standard the large share of new gas generation comes from new NGCC units, while under the blended coal and gas performance standard the larger share of new gas generation comes from existing units. The dual coal and gas performance standards scenario has intermediate results on both counts, but includes the largest expansion of natural gas co-firing and the greatest investment in heat rate improvement at coal units

Finally we note a several fold increase in the price of emissions reductions credits. The value is converted to $ / ton in the table for comparison with the CPP new source complement scenario. It is important to understand that this price per ton is not a measure of marginal social or private cost because it is contingent on the production incentive that is embodied in the emissions rate standard, so it should be interpreted with caution.

The three new scenarios that are modeled lead to roughly a ten percentage point increase in electricity prices in 2030 compared to the CPP new source complement scenario. Another aspect of the cost of these scenarios is a roughly 30 percent increase in the delivered price of natural gas for electricity generation. That price increase will introduce costs on businesses and households that are not represented in the model. As noted, if EPA conducted a standard setting process focused only on inside the fence options, it could presumably select a target that had a smaller impact on gas prices while still achieving equal or greater overall emission reductions.

Table 1. Results for 2030

	Compliance methods restricted to measures at affected sources only			
	Coal-Only Performance Standard	*Dual Coal and Gas Performance Standards*	*Blended Coal and Gas Performance Standard*	*CPP (New Source Complement)*
Emissions				
CO_2 (million short tons)*	749	746	856	1,708
SO_2 (thousand short tons)	90	105	210	1,177
NO_x (thousand short tons)	646	771	713	1,338
Electricity Price ($/MWh)	117	117	115	106
Natural Gas Price ($/MMBtu)	7.8	8.0	7.7	6.0
Allowance Price ($/short ton)**	184	267	107	16
Total Generation (TWh)***	3,876	3,886	3,921	4,121
Coal	71	52	192	1,100
Existing CC Gas	612	658	981	549
New CC Gas	946	777	591	761
New Wind	651	681	616	219
Co-fired Gas	71	159	7	3
Biomass	7	10	8	2
Heat Rate Improvement (Btu/KWh)	57	69	21	38

*CO_2 emissions are from CPP affected EGUs plus new NGCC. Other emissions are from the entire sector.

** Emissions reduction credit prices are converted to allowance equivalents for comparison across scenarios.

*** Total generation is greater than the sum of listed categories.

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