RESOURCES FOR THE FUTURE

Comments to US EPA on the Proposed Affordable Clean Energy Rule

Prepared for the United States Environmental Protection Agency

Alan Krupnick, Maureen Cropper, Robert Kopp, Richard Newell, William A. Pizer, Kevin Rennert, Casey Wichman, Dallas Burtraw, Joshua Linn, and Amelia Keyes

Public Comments
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RESOURCES
FOR THE FUTURE

Richard G. Newell
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US Environmental Protection Agency
EPA Docket Center (EPA/DC), Mail Code 28221T
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Attention Docket ID No. EPA-HQ-OAR-2017-0355

On behalf of Resources for the Future (RFF), I am pleased to share the accompanying comments to the United States Environmental Protection Agency (EPA) on its proposed Affordable Clean Energy (ACE) rule.

For the past several decades, RFF experts have helped decisionmakers better understand air pollution and climate policy challenges. RFF has developed methods for assessing the costs and benefits of possible solutions, such as a clean energy standard, Clean Air Act regulation, and various state-level programs. RFF has an extensive history of expertise in this area, and RFF experts are uniquely positioned to provide unbiased information based on rigorous research and policy analysis.

As you may know, RFF is an independent, nonprofit research institution in Washington, DC. Its mission is to improve environmental, energy, and natural resource decisions through impartial economic research and policy engagement. RFF is committed to being the most widely trusted source of research insights and policy solutions leading to a healthy environment and a thriving economy.

As always, the goal at RFF is to identify the most cost-effective and net-beneficial ways, from an economic perspective, to meet energy policy objectives through regulation, policy, or market mechanisms. To that end, researchers at RFF have been actively analyzing the proposed ACE rule alongside the previous administration's proposed Clean Power Plan.

While RFF researchers are encouraged to offer their expertise to inform policy decisions, the views expressed here are those of the individual authors and may differ from those of other RFF experts, its officers, or its directors. RFF does not take positions on specific legislative proposals. Several RFF experts have provided comments on the issues listed below.

1) The Estimation of Health Co-benefits in EPA's Affordable Clean Energy Rule: Alan Krupnick
2) Methodological Considerations for Updated Social Cost of Carbon Dioxide Estimates: Maureen Cropper, Robert Kopp, Richard Newell, William A. Pizer, Kevin Rennert, Casey Wichman
3) A Rebound Effect Leads to Emissions Increases at Many Plants, States: Dallas Burtraw, Amelia Keyes

4) Determination of the Best System of Emissions Reductions Excludes the Most Potent Option at a Facility: Dallas Burtraw, Joshua Linn, Amelia Keyes

If you have any questions or would like additional information, please contact my colleague Dr. Dallas Burtraw at burtraw@rff.org.

Sincerely,

Comments on the Estimation of Health Co-benefits in EPA's Affordable Clean Energy Rule

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At a press briefing in mid-August, Bill Wehrum, the appointed head of the US Environmental Protection Agency's (EPA's) Air Office, reiterated the Trump administration's position that ancillary benefits are not to be counted in cost-benefit analysis of major rules, this time in the context of the Affordable Clean Energy (ACE) rule proposed to replace the Obama administration's Clean Power Plan (CPP). If only the forgone carbon dioxide (CO2) benefits of pulling back on the CPP are counted, the cost savings from ACE outweigh these forgone benefits. But adding the ancillary health benefits that are lost with the ACE rule—the value of 1,400 fine particulate matter (PM2.5)-associated deaths related to greater coal use under the ACE rule—turns ACE into an economic loser, with net social costs relative to the CPP.

At the briefing, Wehrum said: "We're not dealing with [sulfur dioxide] SO2. We're not dealing with [nitrogen oxides] NOX. We're not dealing with particulate matter. … We have abundant legal authority to deal with those other pollutants directly, and we have very aggressive programs in place that directly target emissions of those pollutants. So our view is, if we want to regulate PM, we regulate PM straight up. If we want to regulate SO2, we regulate SO2 straight up."

The overarching response to this statement is that all benefits and costs of a rule should be considered, based both on principles of welfare analysis and on previous case law. Just because the stated purpose of a rule is to reduce CO2 does not give license to ignore other impacts that occur. As an illustration, environmental rules are not issued to change employment, but are written to protect public health and the environment, making the employment impacts ancillary. Yet any policymaker certainly wants these ancillary impacts on jobs to be considered, including not only employment impacts but also the ancillary health damages that occur from employment loss.

Drawing from comments that my colleague Amelia Keyes and I put together related to ancillary benefits in the context of the CPP repeal, the following bears repeating:

Including co-benefits in foregone benefits calculation

The first set of net benefit estimates presented in the [CPP] RIA are the net benefits associated with the targeted pollutant, CO_2. Foregone health co-benefits are not included. This methodology addresses a concern stated in the news release for the CPP repeal Notice of Proposed Rulemaking (NPRM): "The Obama administration relied heavily on reductions in other pollutants emitted by power plants, essentially hiding the true net cost of the CPP by claiming benefits from reducing pollutants that had nothing to do with the rule's stated purpose."[1]

EPA's statement is incorrect, and the estimation of net benefits that excludes foregone health co-benefits does not represent a full and fair analysis. The true net costs of repeal include the foregone co-benefits because controlling carbon dioxide emissions, given current mitigation options, inevitably will mean reducing other pollutants as well.

[1] https://www.epa.gov/newsreleases/epa-takes-another-step-advance-president-trumps-america-first-strategy-proposes-repeal

Methodological Considerations for Updated Social Cost of Carbon Dioxide Estimates

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On August 31, 2018, the Environmental Protection Agency (EPA) issued a proposed rule, "Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units: Emission Guideline Implementing Regulations; New Source Review Program."[2] With the proposed rule, EPA provided a regulatory impact analysis (henceforth, the RIA) to quantify its effects.[3] The rule proposes to replace a number of previous requirements that would reduce carbon dioxide emissions, and the RIA assesses the associated economic effects of the rule's associated forgone climate benefits by employing an

[2] 83 Fed. Reg. 44746.
[3] US Environmental Protection Agency, "Regulatory Impact Analysis for the Proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program."

updated value for the federal government's social cost of carbon (SC-CO_2), developed under Executive Order 13783. This updated value for the SC-CO_2 and the related methodological changes from the federal government's previous estimation process for the SC-CO_2 are the subject of this comment.

In this comment we make the following three points and associated recommendations for revising the RIA:

1. The limited set of actions that EPA has taken to generate an updated value of the social cost of carbon under Executive Order 13783 are unresponsive to the comprehensive set of recommendations for improving such estimates that were provided in January 2017 at the request of the federal government by the National Academies of Sciences, Engineering, and Medicine (NASEM). We recommend that EPA undertake efforts to apply the near-term recommendations of the NASEM report to the estimation of the SC-CO_2 and in the interim rely on the previous SC-CO_2 estimates.
2. The central analysis focuses exclusively on a domestic value for the SC-CO_2 that omits important economic interactions and considerations related to the global nature of climate change. This biases the estimates downward relative to the true impact on US citizens. If EPA wishes to consider domestically focused damages—in advance of scientific tools that meet the needs identified in the NASEM report—we recommend that EPA consider and present domestically focused SC-CO_2 estimates and global SC-CO_2 estimates together as a range in the central analysis.
3. The adoption of a 7 percent discount rate, which represents the before-tax rate of return on private capital under the Office of Management and Budget's (OMB) Circular A-4,[4] is conceptually inappropriate for SC-CO_2 estimation, as it is methodologically inconsistent with the output of the integrated assessment models used to generate the supporting damage estimates. We recommend that EPA implement the NASEM report's near-term recommendations for discounting and, in the interim, continue to use the previous estimates based on 2.5 percent, 3 percent, and 5 percent discount rates.

The NASEM Report

In its discussion of uncertainty in the SC-CO_2, the RIA highlights potential areas for improvement of the methodology underpinning the federal government's estimation of the SC-CO_2. In response to a study request in 2015 from the federal government's Interagency Working Group on the Social Cost of Carbon that was formerly chartered with developing and maintaining estimates of the social cost of greenhouse gas emissions, a NASEM committee conducted a comprehensive evaluation of potential updates to the estimation methodology for the social cost of carbon dioxide.

On January 11, 2017, the NASEM committee released the culmination of its evaluation in the form of the report, *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide* (henceforth, the NASEM report). The report puts forward conclusions and recommendations on how to

[4] Executive Office of the President of the United States, Circular A-4 (2003), available at https://www.whitehouse.gov/omb/circulars_a004_a-4 (accessed November 4, 2017).

improve the conceptual underpinnings, empirical methods, and data used to calculate the SC-CO_2, as well as the transparency and flexibility of the process by which future estimates are generated.[5]

The results and recommendations of this report, though focused on the calculation of damages resulting from the emissions of carbon dioxide, are also broadly applicable to the social costs of other greenhouse gases, such as methane and nitrous oxide. The NASEM report addresses many of the issues highlighted in the RIA, among others.

Major Recommendations of the NASEM Report: Integrated Framework, Scientific Criteria, and Process

The NASEM report offers:

"Both near- and longer-term recommendations [that] provide guidance to improve the scientific basis, characterization of uncertainty, and transparency of the SC-CO_2 estimation framework within the federal regulatory context for which the SC-CO_2 was developed.

"The committee specifies criteria for future updates to the SC-CO_2. It also recommends an integrated modular approach for SC-CO_2 estimation to better satisfy the specified criteria and to draw more readily on expertise from the wide range of scientific disciplines relevant to SC-CO_2 estimation. Under this approach, each step in SC-CO_2 estimation is developed as a module—socioeconomic, climate, damages, and discounting—that reflects the state of scientific knowledge in the current, peer-reviewed literature.

"Because it is important to update estimates as the science and economic understanding of climate change and its impacts improve over time, the committee recommends that estimates of the SC-CO_2 be updated in a three-step process at regular intervals of approximately 5 years. This timing would balance the benefit of incorporating evolving research against the need for a thorough and predictable process. For each module, the committee recommends near-term changes given the current state of the science. The recommended changes would be feasible to implement in the next 2-3 years and would improve the performance of each part of the analysis with respect to the primary criteria."[6]

We note with concern that the technical efforts and process involved in producing the new SC-CO_2 estimates as part of EPA's proposed rule are not responsive to the NASEM report's major recommendations for establishing an integrated framework, applying recommended scientific criteria, or following a regularized process that incorporates scientific peer review and focused public comment. We recommend that EPA undertake efforts to apply the near-term recommendations of the NASEM report to the estimation of the SC-CO_2 and in the interim rely on the previous SC-CO_2 estimates.

Adoption of Domestic Rather than Global Damages

An important departure from the federal government's previous methodology for estimating the SC-CO_2 is EPA's decision to count only direct domestic benefits from carbon mitigation in its calculation of updated SC-CO_2 values under Executive Order 13783. Though this choice is consistent with a narrow application of prior regulatory analysis practice under OMB's Circular A-4, it is unnecessarily and unreasonably constrained for addressing inherently global pollutants such as greenhouse gases. US greenhouse gas emissions account for about 14 percent of the global total. If all countries considered only

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[5] National Academies of Sciences, Engineering, and Medicine (NASEM), *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide* (Washington, DC: National Academies Press, 2017), available at https://doi.org/10.17226/24651.

[6] NASEM, *Valuing Climate Damages*, Executive Summary, pp. 2–3.

the domestic effects of their greenhouse gas emissions, about 86 percent of climate change impacts on US citizens would be ignored—considered in no decision. An analytic focus solely on direct impacts to the United States of US emissions, when generalized, therefore omits the vast majority of the total impacts the United States faces from climate change.

In addition, damages from US emissions of greenhouse gases are felt not just within US borders, but also abroad. Though such damages occur on foreign soil, their economic effects can be felt within the United States through the globally interconnected economy. As the NASEM report stated, current integrated assessment models do not take full account of "potential implications of climate impacts on, and actions by, other countries, which also have impacts on the United States,"[7] which could affect the United States "through such pathways as global migration, economic destabilization, and political destabilization."[8] Regulatory actions taken by the United States also may be reflected in policy actions taken by other countries; perhaps the clearest example of such reciprocal action is the Canadian government's full incorporation in its own regulatory analysis of the prior US federal values for the social costs of carbon dioxide, methane, and nitrous oxide.

This set of complicated global interactions is an important component of any complete calculation of damages felt by US citizens from domestic emissions, but it is omitted in EPA's revised methodology. In the absence of this full set of considerations, EPA's updated SC-CO_2 estimates are biased downward. Although the scientific, economic, and geopolitical basis of climate change as a global problem should inform reasoned decisionmaking, if EPA wishes to consider domestically focused damages—in advance of scientific tools that meet the needs identified in the NASEM report—we recommend that EPA consider and present domestic-focused SC-CO_2 estimates and global SC-CO_2 estimates together as a range in the central analysis.

Use of a 7 Percent Discount Rate

EPA has also departed from the federal government's prior approach to discounting in its calculation of the SC-CO_2 by adopting a 7 percent discount rate. Though the addition of an estimate calculated using a 7 percent discount rate is consistent with past regulatory guidance under OMB Circular A-4, it is inappropriate for use in estimating the SC-CO_2 through EPA's methodology. The integrated assessment models used to generate the estimates report their output in terms of "consumption-equivalent" impacts, which are intended to reflect the effective impact on people's consumption (as opposed to investment). Standard economic practice is to discount consumption equivalents at the "consumption rate of interest"—which, according to OMB's current guidance, is a 3 percent discount rate.

It is therefore inappropriate to use such modeling results with OMB's 7 percent discount rate, which is intended to represent the historical before-tax return on private capital. None of the researchers whose model results were used to generate the updated values employ a discount rate as high as 7 percent in their work. In addition to using the 3 percent rate, the prior SC-CO_2 estimates also included sensitivities using 2.5 percent and 5 percent discount rates, which were modifications of the 3 percent consumption discount rate to take into account uncertainty in future economic growth and potential correlations between economic growth and climate damages. Moreover, a recent report from the Council of Economic Advisers found that evidence supports a rate lower than 3 percent as the norm for the consumption rate of

[7] NASEM, *Valuing Climate Damages*, Conclusion 2-4, pp. 9, 53.

[8] NASEM, Valuing Climate Damages, pp. 9, 53.

discount, which it suggested should be at most 2 percent, given historical trends and expected future conditions.[9]

The NASEM report recommended that discounting occur via use of what is termed the "Ramsey formula" with parameters "that are consistent with theory and evidence and that produce certainty-equivalent discount rates consistent, over the next several decades, with consumption rates of interest."[10] This recommendation is relatively straightforward to implement, as it does not require significant new model development. Nonetheless, this recommendation not been adopted in the RIA. Rather, as described above, the RIA introduces a discount rate that is not based on the consumption rate of interest.

For those reasons, we recommend that EPA implement the near-term recommendations of the NASEM report with respect to discounting and, in the interim, continue to use the previous estimates based on 2.5 percent, 3 percent, and 5 percent discount rates.

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[9] Council of Economic Advisers (CEA), *Discounting for Public Policy: Theory and Recent Evidence on the Merits of Updating the Discount Rate* (2017), available at https://obamawhitehouse.archives.gov/sites/default/files/page/files/201701_cea_discounting_issue_brief.pdf (accessed November 4, 2017).

[10] NASEM, Valuing Climate Damages, Recommendation 6-2, pp. 19, 180.

A Rebound Effect Leads to Emissions Increases at Many Plants, States

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The proposed Affordable Clean Energy (ACE) Rule is limited in scope to the technological systems at individual power plants and focuses exclusively on emissions reductions that could be achieved through heat rate improvements at plants. An unintended consequence of this approach is that emissions will increase at many of these power plants.

As described below, we consider as a central case for the proposed regulation from among the scenarios in the EPA's Regulatory Impact Assessment (RIA) (EPA 2018b) the 4.5 percent Heat Rate Improvement at $50/kW scenario. In 2030 this scenario will result in an increase in emissions at approximately 28 percent of the regulated coal plants compared to having no policy in place, according to modeling released by the EPA. This corresponds to an increase in emissions in eighteen states plus the District of Columbia compared to no policy. Of the eighteen states that experience total increases in CO_2 emissions, fourteen states experience an emission increase from coal-fired power plants in their state. Because the required investments cause the plants to be more efficient, their lifetimes are often extended. In 2050, total CO_2 emissions from regulated sources are expected to increase compared to no policy. The lifetime emissions of a plant are of consequence because greenhouse gases are long-lived pollutants that accumulate in the atmosphere. The RIA also describes increases in conventional air pollutants (sulfur dioxide, nitrogen oxides and mercury) that are expected to occur in many states, in some cases interfering with progress to achieve National Ambient Air Quality Standards in those states.

The CO_2 emissions impacts of the ACE have implications for the twenty states that have adopted greenhouse gas emissions targets (C2ES 2018). Twenty-two states plus DC are projected to have higher emissions under the ACE compared to the CPP, and eleven of these states plus DC currently have greenhouse gas emissions targets in place. These states can be expected to face more difficulty achieving their targets due to the replacement of the CPP. Further, of the eighteen states and DC projected to experience higher CO_2 emissions compared to no policy, seven—California, DC, Florida, Maryland, Massachusetts, New York and Oregon—have greenhouse gas emissions targets. For these states, achieving their emissions targets may be more difficult under the ACE compared to having no federal power plant carbon standard in place.

The possibility for emissions increases at individual plants and in entire states is due to the rebound effect, which we describe in detail below. The increase in emissions raises the question whether the heat rate improvement standard proposed under ACE qualifies as the Best System of Emissions Reduction (BSER) that EPA is charged with identifying in its development of a power plant carbon standard under section 111(d) of the Clean Air Act. The projected impact of the rebound effect on CO_2 emissions under the ACE should be taken into consideration in determining whether the BSER requirement has been satisfied.

Analysis Provided in this Comment

In this comment we explain the reasons why an increase in emissions is expected to occur at roughly 28 percent of the technological systems regulated under the ACE proposal, and we describe the emissions changes that are expected. In addition to cited sources, the analysis described here is based on a manuscript under review (Keyes et al. 2018b).

Each of the three ACE scenarios modeled in the RIA assumes uniform heat rate improvement (HRI) potential at all coal plants and uniform cost per kW of HRI investment. They differ in their assumptions about the status of the New Source Review (NSR) provision of the U.S. Clean Air Act. Our analysis of EPA's modeling focuses on emissions outcomes in 2030 for what we identify as the central case: the 4.5 percent HRI at $50/kW scenario. We choose this scenario as our ACE central case because it incorporates the implementation of EPA's proposed NSR reform and a lower cost of HRI investment. Of the other two ACE scenarios, one alters the NSR reform assumption and one assumes a higher HRI investment cost. We also compare these results with the other two ACE scenarios.

The increase in emissions at many power plant systems across all three scenarios results from what is known in the economics literature as the "rebound effect," a phenomenon in which facilities that are made more efficient through investments to reduce their heat rates consequently operate more frequently and remain in operation for a longer period. The regulation would cause these investments to occur and results in an increase in the operation of these facilities that frequently outweighs their efficiency improvement, resulting in an overall increase in emissions at facilities.

Source-Based Regulation

The proposed ACE employs a narrow "source-based" regulation, which defines and limits the legally relevant BSER to be heat rate improvement opportunities at individual coal plants. ACE sets standards for emissions rate improvements at facilities, but because these standards are based solely on estimated potential for heat rate improvements, we refer to this type of source-based option as a heat rate improvement standard. Heat rate is the amount of fuel input (Btu) used to produce a kWh of electricity; a lower heat rate indicates a more efficient unit, which emits less CO_2 per kWh. As a rule of thumb, a reduction of 10 million Btu equals roughly a one-ton reduction in CO_2 for coal EGUs. There is considerable heterogeneity in the heat rate of U.S. coal plants and opportunity to make coal plants more efficient (Linn et al. 2014, Sargent & Lundy 2009, Staudt & Macedonia 2014, DiPietro & Krulla 2010, DOE/NETL 2009, MIT 2009, SFA 2009, Campbell 2013). The ACE is expected to induce investments at coal-fired plants to reduce their heat rates.

National and State Level CO_2 Emissions Changes

In all three ACE scenarios, the RIA projects that national CO_2 emissions will be slightly lower under the ACE compared to no policy, and higher compared to the CPP, in all modeled years but 2050 (Table 1). In 2050, two of the three ACE scenarios have higher CO_2 emissions compared to no policy. Cumulative CO_2 emissions from 2021–2050 are slightly lower under all three ACE scenarios compared to no policy and slightly higher compared to the CPP.

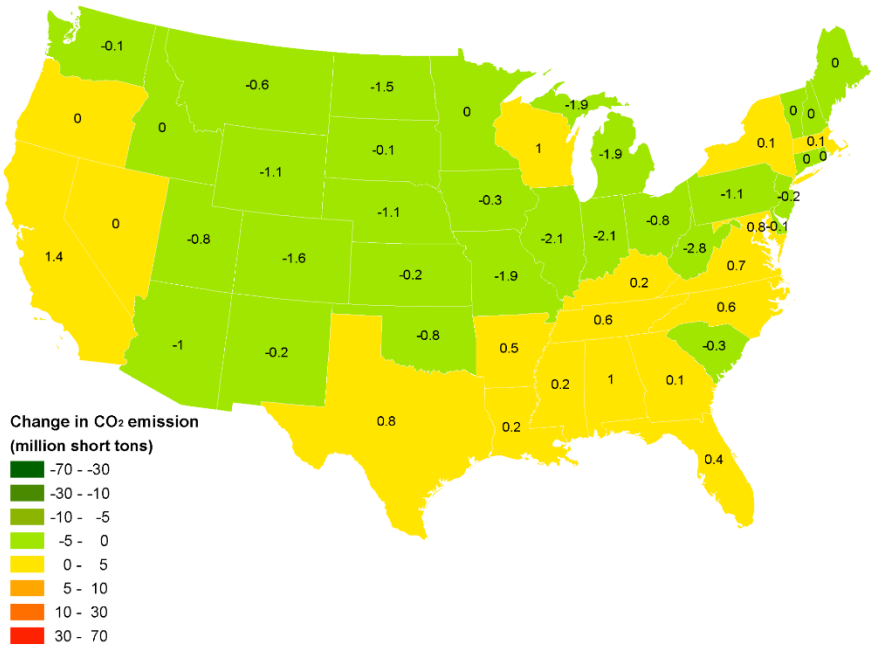
Table 1: National Power Sector CO_2 Emissions (million short tons)

	No Policy	CPP	4.5% HRI at $50/kW (ACE Central Case)	2% HRI at $50/kW	4.5% HRI at $100/kW
2021	1,710	1,701	1,709	1,709	1,707
2023	1,801	1,754	1,814	1,801	1,802
2025	1,829	1,780	1,812	1,816	1,799
2030	1,811	1,737	1,797	1,798	1,785
2035	1,794	1,728	1,787	1,783	1,772
2040	1,849	1,782	1,841	1,840	1,829
2045	1,843	1,782	1,832	1,833	1,821
2050	1,804	1,753	1,815	1,801	1,808
2021-2050 Cumulative (interpolated)	**54,469**	**52,694**	**54,261**	**54,195**	**53,920**

Keyes et al. 2018b

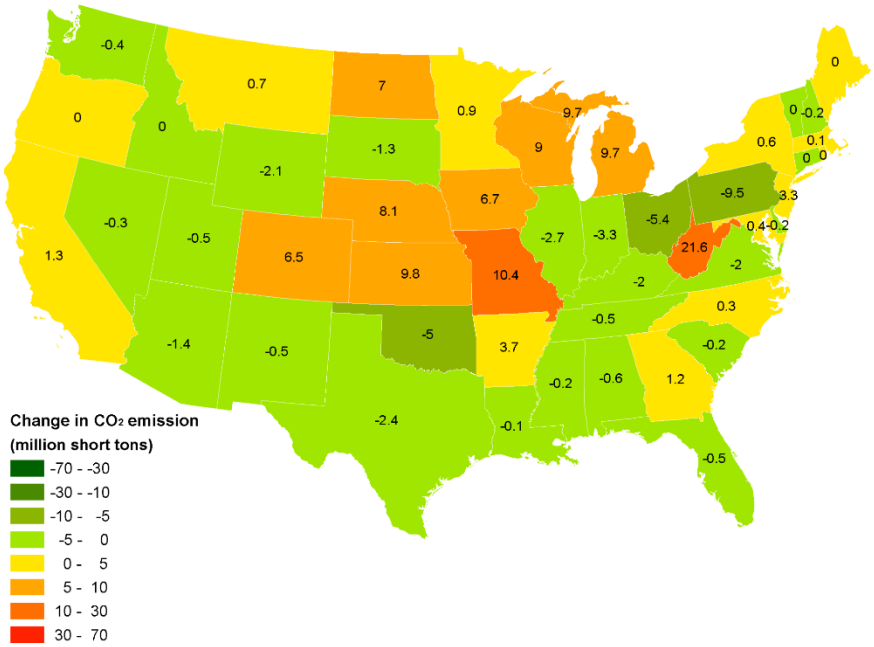
We focus on 2030 emissions for the central case, 4.5 percent HRI at $50/kW. According to EPA, CO_2 emissions are estimated to be 14.3 million short tons (0.8 percent) lower compared to no policy and 59.9 million short tons (3.5 percent) higher compared to the CPP. There is substantial variation in state-level outcomes from the ACE. Eighteen states plus the District of Columbia are projected to experience at least small increases in CO_2 emissions in 2030 under the ACE compared to no policy (Figure 1). Compared to the CPP, 22 states and Washington, DC are projected to have emissions increases (Figure 2).

Figure 1: CO_2 Emissions under ACE Central Case compared to No-Policy Case, 2030



Keyes et al. 2018b

Figure 2: CO_2 Emissions under ACE Central Case compared to CPP Case, 2030



Keyes et al. 2018b

Coal-Fired Power Plant CO_2 Emissions Changes

We examine the impact of the ACE on model coal-fired power plants to illustrate the main drivers of emissions changes. IPM's model coal plants are aggregated representations of constituent coal plants within states, 381 of which were operating in the U.S. in 2016 (EIA 2017a). Under EPA's projections of ACE, CO_2 emissions from coal plants are projected to be only slightly lower (0.6 percent) in 2030 compared to no policy (Table 2). While the emissions intensity of coal plants declines by 4.5 percent, the number of coal plants in operation and total coal-powered electricity generation increase. This rebound effect offsets the benefits of emissions intensity improvements and causes the total emissions reduction to be small compared to the emissions intensity improvements. Total CO_2 emissions are projected to increase at a number of the affected plants. Of the 333 model coal plants that would be in operation in 2030 under no policy, 93 of those (or 28 percent) are projected to have higher total CO_2 emissions under the ACE. Additionally, under the ACE five additional model coal plants are projected to be operating in 2030 that would have been idled or retired under no policy.

Table 2: Comparison of model coal plants between ACE Central Case and No-Policy Case, 2030

	No Policy	ACE Central Case	Change (level)	Change (percent)
Number of Model Coal Plants in Operation	333	338	5	1.5%
Total Generation (GWh)	937,757	975,633	37,877	4.0%
Total Emissions (Thousand short tons)	1,027,456	1,020,897	-6,559	-0.6%
Emissions Intensity (kg/kWh)	0.99	0.95	-0.04	-4.5%
Heat Rate (Btu/kWh)	10,395	9,930	-465	-4.5%

Keyes et al. 2018b

Understanding the Reason for Emissions Increases Under the Proposal

We conducted a formal decomposition analysis of the estimated national changes in generation and CO_2 emissions between the ACE and a scenario with no policy to examine the underlying drivers of the emissions changes and to estimate the contribution of a potential emissions rebound effect. We focus on the impacts of ACE based on 2030 results for what we label as a central case, selected from EPA's three illustrative ACE modeling scenarios.

To analyze estimated changes in EGU generation and associated emissions, we use a logarithmic mean decomposition index (LMDI) approach, based on Ang (2015). The method is described in more detail in Palmer et al. (2018) and Keyes et al. (2018a).

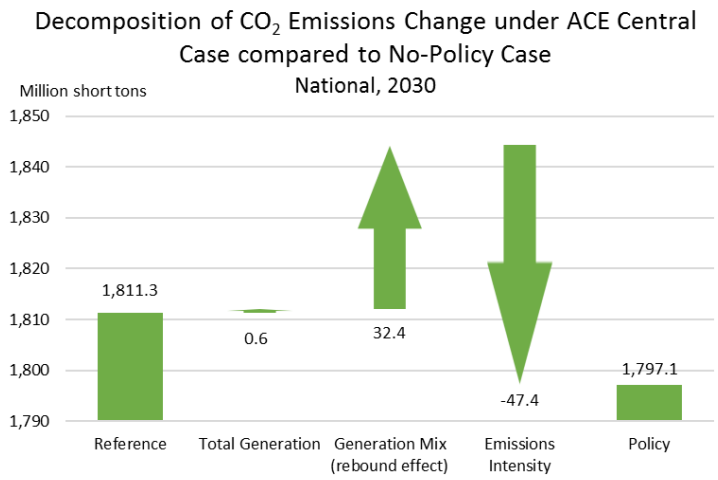
We estimate the contribution of three factors to the change in emissions under the ACE compared to the no-policy scenario: activity, structure, and intensity. The activity factor refers to emissions changes due to changes in total electricity generation; the structure factor is emissions changes associated with shifts in generation among fuel types; and the intensity factor is emissions changes due to changes in emission intensity within fuel types. The emission intensity of fuel types (the intensity factor) is the factor targeted by a heat rate improvement standard, and it can differ across scenarios when policies cause various fossil fuel plants to improve their efficiency. Under a heat rate improvement standard, the intensity factor contributes to reductions in emissions if the standard successfully reduces the emission intensity of coal plants.

The rebound effect is embodied in changes in the generation mix (the structure factor), which changes across scenarios when policies affect the relative competitiveness of generation sources. This shift can occur under a heat rate improvement standard if the regulation improves the efficiency of coal plants and thus causes substitution towards coal away from other, lower-emitting generation sources. Our estimate of the rebound effect is likely conservative because the EPA's model holds total demand constant. If demand were to change, the rebound effect would include both the structure factor and the activity factor. This change can occur if the increased efficiency of coal lowers the cost of electricity generation and thus increases total electricity demand, as would be expected in organized wholesale power markets. Although electricity demand is held constant, total electricity generation (the activity factor) can still differ across model scenarios for several reasons: policies may cause changes in trade flows between the U.S. and

Canada, or changes in state or regional generation within the U.S. These changes may affect the total amount of electricity transferred between regions, thus affecting total losses and generation.

The decomposition shows the extent to which the rebound effect is projected to offset emissions reductions under the ACE. Total national emissions under the ACE are estimated to decrease by 14.3 million short tons (0.8 percent) compared to the no-policy scenario in 2030. Our decomposition analysis breaks down the three primary factors driving that change in emissions (Figure 3a). We find that reductions in emissions intensity within fuel types reduce emissions by 47.4 million tons, mainly due to the lower emissions intensity of coal generation. However, the rebound effect associated primarily with greater utilization of coal plants is estimated to increase emissions by 32.4 million tons, partially offsetting the reductions from improvements in emissions intensity and resulting in smaller estimated total reductions. Note that the rebound effect is greater on a fleet basis, due to substitution to more efficient units, than researchers have estimated for an individual facility (e.g. Linn et al. 2014). A slight increase in total electricity generation drives emissions up by an additional 0.6 million tons.

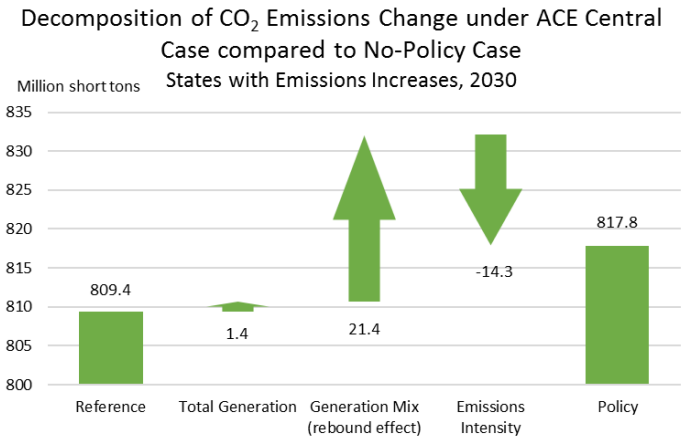
Figure 3a



Keyes 2018b

For the eighteen states plus DC projected to experience higher CO_2 emissions in 2030 under the ACE compared to no policy (Figure 1), total CO_2 emissions are expected to increase by 8.5 million tons. Decomposition reveals that emissions intensity improvements drive down emissions by 14.3 million tons, but these reductions are more than offset by generation mix shifts that drive up emissions by 21.4 million tons (Figure 3b). This rebound effect is caused mostly by shifts towards increased coal generation. Of the eighteen states that experience total increases in CO_2 emissions, fourteen states experience an emissions increase from coal-fired power plants in their state. In the other four states (California, Georgia, Massachusetts, and Oregon) plus DC, the emissions increases are mainly due to increased emissions from natural gas. Increases in state-level natural gas emissions could occur for several reasons that are specific to state and regional electricity markets. This pattern exposes another unintended consequence of the ACE that could diminish emissions reductions in some states.

Figure 3b

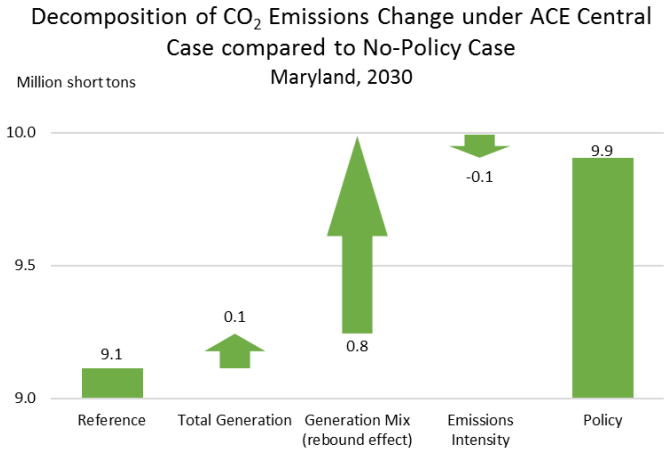


Note: States with emissions increases are AL, AR, CA, DC, FL, GA, KY, LA, MD, MA, MS, NV, NY, NC, OR, TN, TX, VA, WI.

Keyes 2018b

Maryland has the greatest percent increase in emissions under the ACE compared to no policy in 2030 (8.7 percent) and it provides an informative illustration of the emissions rebound effect. Maryland has two model coal plants in operation under the ACE, neither of which would be in operation with no policy in place. Thus, the shift in the generation mix towards coal drives up emissions by 0.8 million tons and causes an overall increase in emissions in the state (Figure 3c).

Figure 3c



Keyes 2018b

Criteria Air Pollutant Emissions Changes

National SO_2 emissions in 2030 are projected by EPA to decrease by 0.7 percent under the central case ACE compared to no policy, with nineteen states showing SO_2 emissions increases (Figure 4). National NO_X emissions are projected to decrease by 1.0 percent, with twenty states plus DC showing emissions increases (Figure 5). Compared to the CPP, national SO_2 emissions are projected to be 5.9 percent higher under ACE and NO_X emissions are projected to be 5.0 percent higher.

Figure 4: SO_2 Emissions under ACE Central Case compared to No-Policy Case, 2030

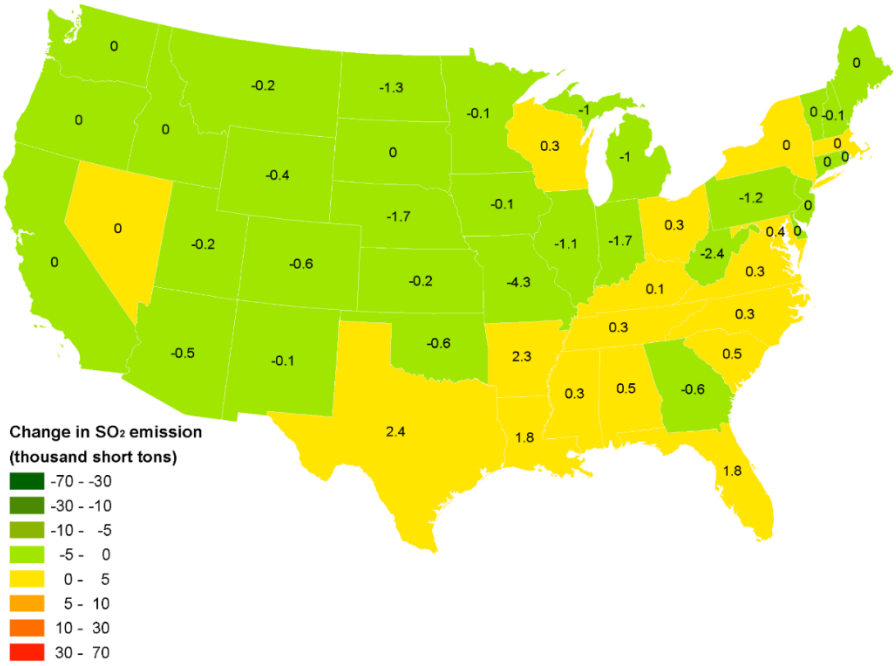


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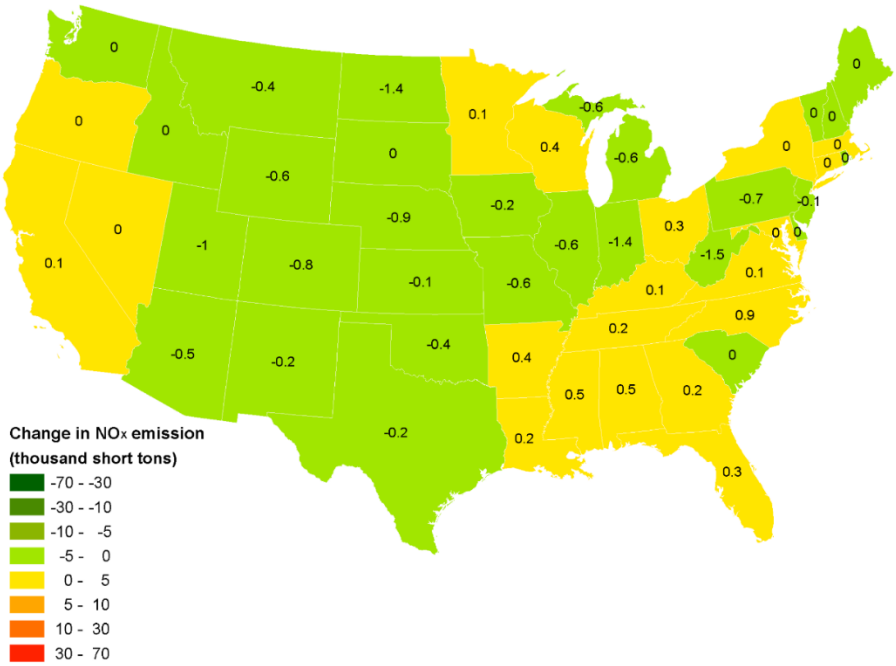
Figure 5: NO_X Emissions under ACE Central Case compared to No-Policy Case, 2030



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Related Findings in the Economics Literature

Previous studies have found evidence that a rebound effect is associated with heat rate improvements at high-emissions rate facilities, and changes in the operation of these facilities diminishes the reduction in emissions that would otherwise occur (Linn et al. 2014). Moreover, because these facilities have lower operating costs after the heat rate improvements are made, they are likely to delay their ultimate retirement and may remain in service longer into the future (Burtraw et al. 2011).

We compare the results from EPA's modeling to Keyes et al. (2018a), an independent study that models the spatially explicit effects of a source-based heat rate improvement standard similar to ACE. The analysis uses results from IPM to compare a source-based scenario to a no-policy scenario and a systems-based scenario similar to the CPP. Keyes et al. (2018a) also find that a rebound effect could lead to emissions increases at individual plants and in some states. While the qualitative results confirm those presented in this paper, the estimated emissions impacts differ somewhat between the two analyses (Table 3). This is primarily because baseline economic conditions differ between the two sets of model runs—Keyes et al. (2018) uses power sector modeling based on the electricity industry as it was configured in 2014, and the industry has since undergone substantial changes including retirement of many fossil units. Coal generation declined from 40 percent of total power generation in 2013 to 31 percent of total generation in 2017, and overall fossil fuels supplied 62 percent of total generation in 2017 compared to 67 percent in 2013 (EIA 2018). Emissions under the no-policy case are therefore expected to be lower for the new modeling results. The analyses also employ different assumptions about policy design and implementation. For example, the source-based standard used in Keyes et al. (2018a) includes cofiring up to 15 percent with natural gas or biomass as a compliance option, while the ACE does not consider cofiring as a candidate technology for BSER.

Table 3: Comparison of source-based scenario modeling results for 2030.

	Analysis based on EPA's ACE RIA Keyes et al. (2018b)	**Keyes et al. (2018a)**
CO_2 Emissions under Source-based scenario, million short tons	1,797	2,386
CO_2 Emissions under No-Policy scenario, million short tons	1,811	2,451
Difference	*-0.8%*	*-2.6%*
CO_2 Emissions under Systems-based scenario, million short tons	1,737	1,466
Difference	*3.5%*	*63%*
Number of States with Emissions Increase Compared to No Policy scenario	18 states plus DC	8 states
Number of States with Emissions Increase Compared to Systems-based scenario	22 states plus DC	46 states

Keyes 2018b

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Co-Firing and Determination of the Best System of Emissions Reductions

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EPA is directed under the Clean Air Act (CAA) section 111(d)(1) to enact regulations that establish a procedure under which states submit plans that establish "standards of performance" for emissions of certain air pollutants. The standard of performance must reflect achievable emissions reductions based on the "best system of emissions reduction" (BSER), and EPA is authorized to determine the BSER by identifying adequately demonstrated systems of emission reduction and taking into account the cost of achieving the reductions, remaining lifetime of a facility, and any non-air quality health and environmental impact and energy requirements (83 FR 44755).

It is critical for EPA to sufficiently consider the availability and cost-effectiveness of all candidates for the BSER because the emission reductions deemed achievable under the BSER are the basis for establishing standards of performance. Omitting a feasible and cost-effective option from the BSER could substantially reduce the amount of emissions reductions that the proposed Affordable Clean Energy (ACE) rule achieves.

The proposed rule identifies heat rate improvements at existing coal-fired EGUs as the BSER. The EPA proposes to exclude co-firing of biomass or natural gas from BSER. In this comment, we report analysis using data from the EPA and Energy Information Administration (EIA) in which we:

- Document the prevalence of co-firing across the power sector, as 37 percent of coal-fired boilers co-fired with natural gas or biomass in 2017;
- Show that co-firing is geographically widespread, occurring in in 34 states in 2017;
- Estimate that expanding natural gas co-firing could reduce emissions by at least 5-15 million tons of carbon dioxide (CO_2) at a cost of roughly $36 per short ton;
- Show that at least 29 percent of plants that burn coal are in proximity to a supply of biomass;
- In response to solicitation of comment C–20, we show there is ample supply of woody biomass without the need to convert land to non-forest uses, and that biomass generation could increase at least two-fold based on available supply;
- Urge the EPA to reconsider including co-firing as BSER, based on this evidence.

Data used for co-firing analysis

We have assembled EPA and EIA data to assess the prevalence of co-firing in recent years. The data from Form EIA-923 include annual fuel consumption by fuel type for all boilers surveyed. We use EIA-923 data from 2017 and identify plants with boilers that reported consuming any amount of coal throughout the year. We limit the list of plants to those in the Electric Utility and Independent Power Producer non-combined heat and power sectors. Using the boiler-level fuel consumption data for this list of plants, we identify boilers that burned both coal and natural gas and those that burned both coal and biomass.

The EPA data include hourly generation, heat input, sulfur dioxide (SO_2), and CO_2 emissions for all generation units included in the Continuous Emissions Monitoring System (CEMS). We use CEMS data from 2015 and include the plants identified in the EIA-923 data that burned coal in 2017.[11]

Unfortunately, the CEMS data do not report which fuel is burned during each hour. For that reason, we determine whether the unit burns coal or natural gas based on its SO_2 emissions rate. Specifically, we infer that the unit burns gas during a particular hour if the SO_2 emissions rate is below 0.001 pounds of SO_2 per million British thermal units (lb/MMBtu). We conduct sensitivity analysis around this threshold.

To assess the availability of natural gas fuel supply we direct the reader to a report prepared by M.J. Bradley & Associates, LLC, *Pipeline Analysis Results*, that is referenced in comments filed in this docket by the Environmental Defense Fund. To assess the availability of woody biomass we rely on data from the US Department of Agriculture Forest Service Forest Inventory and Analysis National Program (FIA), which reports the availability of net woody biomass within fifty miles of a biomass-burning plant in 30 eastern U.S. states from 2009 to 2015.[12] Looking back to 2009, the data reveal relatively modest variation on an annual or a month-by-month basis in most states. We consider data from 2015.

Prevalence of co-firing

From the EIA data, we conclude that burning of natural gas at units that also burn coal is widespread: 35 percent of the boilers that burned coal also burned natural gas in 2017 (Table 1). These boilers are spread across 33 states (Figure 1). This prevalence indicates that over one-third of coal-burning plants, located in many regions, have access to natural gas pipelines.

Biomass co-firing was less common but has a substantial geographic range, with two percent of coal-fired boilers burning biomass across seven states in 2017. Combined, natural gas and biomass co-firing occurred across 34 states. For boilers that co-fired with biomass, biomass comprised a relatively high share of total fuel consumption, with a median share of 50 percent. The share of natural gas tended to be lower, with a median of 0.7 percent, but ranged from 0.001 percent to 99.7 percent.

The top half of Table 1 presents results at the boiler level, and the bottom half presents results at the plant level. The average cost of coal at plants that co-fired with natural gas was 8 cents/MMBtu lower than the average cost of coal at all plants. In contrast, the cost of coal at plants that co-fired with biomass was 50 cents/MMBtu higher than the average. The high coal prices at these plants suggest that the plants co-firing with biomass may have been doing so for economic reasons, which suggests that co-firing with biomass is an economical way to reduce emissions.

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[11] Below we report one set of analysis using the EIA data and another set using the EPA data. The two sets of analysis use the same set of plants, all of which burned coal in 2017.

[12] Data provided by Ram Dahal and Francisco Aguilar at the University of Missouri.

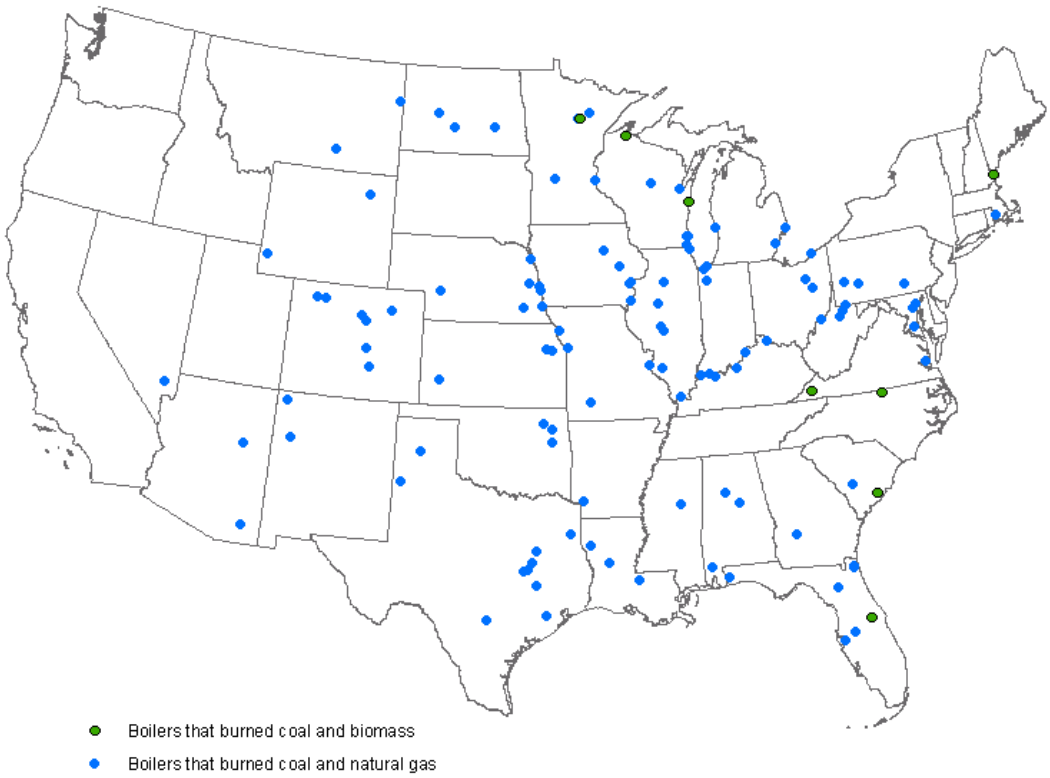
Table 1. Boilers that Burned Coal and Other Fuel (Natural Gas or Biomass) in 2017

	Natural Gas	Biomass
Boiler level information		
Number of boilers that burned coal and other fuel	228	14
Percent of all boilers that burned coal	*35%*	*2%*
Number of states	33	7
Plant level information		
Average coal fuel cost at plants with boilers that burned coal and other fuel (cents/MMBtu)	204	262
Difference from average coal cost at all plants that burned coal (cents/MMBtu)	*-8*	*50*
Cost of other fuel at plants with boilers that burned coal and other fuel (cents/MMBtu)	365	Not available

Source: EIA Form 923.

Note: Analysis is based on a total of 653 boilers in the Electric Utility and IPP Non-CHP sectors that reported burning coal in 2017.

Figure 1. Boilers that Co-Fired with Coal and Natural Gas or Biomass, 2017



Opportunities for expanding natural gas co-firing

We find that increasing co-firing of natural gas could reduce CO_2 emissions by at least 5 to 15 million tons per year. This number is substantial compared to the emissions reductions that EPA projects for the ACE. We estimate that reducing emissions by switching from coal to natural gas at coal units would cost $35.65 per ton of CO_2 reduction. For reasons explained below, our estimates of the emissions abatement potential are conservative, meaning that greater emissions reductions at the same cost per ton would be possible.

We estimate the opportunity for natural gas co-firing using the CEMS data. We consider coal-fired units that already co-fired with natural gas in 2015 and assume that they could increase the amount they co-fire based on the maximum amount of co-firing during a month within the year. For example, if a unit co-fired more in June than in other months, and that unit co-fired 10 percent of the hours during June, we assume that the unit could have co-fired 10 percent of the time during all other months of the year. Based on typical emissions rates for natural gas and coal, we estimate that the increased use of natural gas at the coal units that already co-fired could reduce CO_2 emissions by 5 to 15 million tons per year.[13]

[13] We assume emission rates of 0.05 tons/MMBtu and 0.1 tons/MMBtu for natural gas and coal, respectively. We also assume that each unit's heat rate is the same when burning coal or natural gas. The range of results reflects the SO_2 emissions rates used to identify natural gas generation. These calculations include the implicit assumption that the unit burns either coal or gas during the hour but not both. Unfortunately, the CEMS data do not allow us to relax this assumption.

These estimates rest on two assumptions. The first is that the plant has access to a natural gas pipeline. This assumption is reasonable because the analysis includes only plants that co-fire at least some of the time, which is only possible if they have access to pipelines. The second assumption is that the unit is able to co-fire at its maximum observed monthly rate throughout the year. This assumption is reasonable because we observe units co-firing throughout the day and during all weeks of the year. The mean probability that a coal unit used gas in any hour in 2015 is 4 percent. Units were slightly less likely to use gas in the first weeks of the year, but otherwise co-firing varied little across the year. Because we confine the analysis to units that are observed to co-fire and because co-firing varied little across the year, our estimates are conservative and can be considered a lower bound of the opportunity for emissions abatement from co-firing with natural gas. Further, we do not consider the possibility that other plants that do not already co-fire with natural gas could do so.

Our lower bound estimates of the abatement potential are comparable to the emissions reductions that EPA projects from heat rate improvements under the proposed ACE. EPA's Integrated Planning Model (IPM) projections of three illustrative ACE scenarios include heat rate improvements that reduce CO_2 emissions by 7 to 18 million tons per year.[14] If the BSER in the ACE included natural gas co-firing in addition to heat rate improvements, potential emissions reductions would be greater than EPA currently estimates.

Increasing natural gas co-firing can be a cost-effective option for reducing CO_2 emissions. In 2017, coal-burning plants that co-fired with natural gas paid $2.04 per MMBtu for coal and $3.65 per MMBtu for natural gas (Table 1), similar to average fuel costs across all coal-burning plants. We estimate that the cost of abatement from switching from coal to natural gas at coal units, keeping generation constant, is $36 per ton of CO_2 emissions reduction.[15] This is an average estimate that would vary by plant due to regional and seasonal differences in relative fuel prices. Thus, we conclude that co-firing is technically feasible and that the costs are reasonable compared to other emissions reductions approaches that EPA considers to be part of BSER.

In its justification for excluding natural gas co-firing from BSER in the proposed ACE rule, EPA points out that natural gas co-firing in coal units is not the most efficient use of natural gas and suggests that redirecting natural gas from natural gas combined cycle (NGCC) units would not be an environmentally positive outcome. While this may be true, EPA has determined that its regulatory authority applies only to source-based emissions reductions opportunities. In the CPP final rule, some co-firing measures were determined to be technically feasible and cost-effective, and co-firing was excluded from the BSER because it was a less efficient option compared to shifting generation from coal units to NGCC units. Because generation shifts among affected EGUs are not part of BSER in the ACE, EPA should not compare co-firing to these options and should only compare co-firing to heat rate improvements. In fact, the costs of co-firing appear to be comparable to the costs of the heat rate improvements that EPA includes in BSER.

Opportunities for expanding biomass co-firing

Given available data and time, we are not able to estimate the potential for emissions reductions from biomass co-firing. Nevertheless, we show that there are opportunities for coal-burning plants to access

[14] Based on interpolated annual emissions projections from 2021-2050, comparing the three illustrative ACE scenarios to the no-policy scenario.

[15] We assume emission rates of 0.05 tons/MMBtu and 0.1 tons/MMBtu for natural gas and coal, respectively. We assume the heat rate (MMBtu/kWh) for a steam boiler using coal is 0.010043 and for a steam boiler using gas is 0.010353 (https://www.eia.gov/electricity/annual/html/epa_08_02.html).

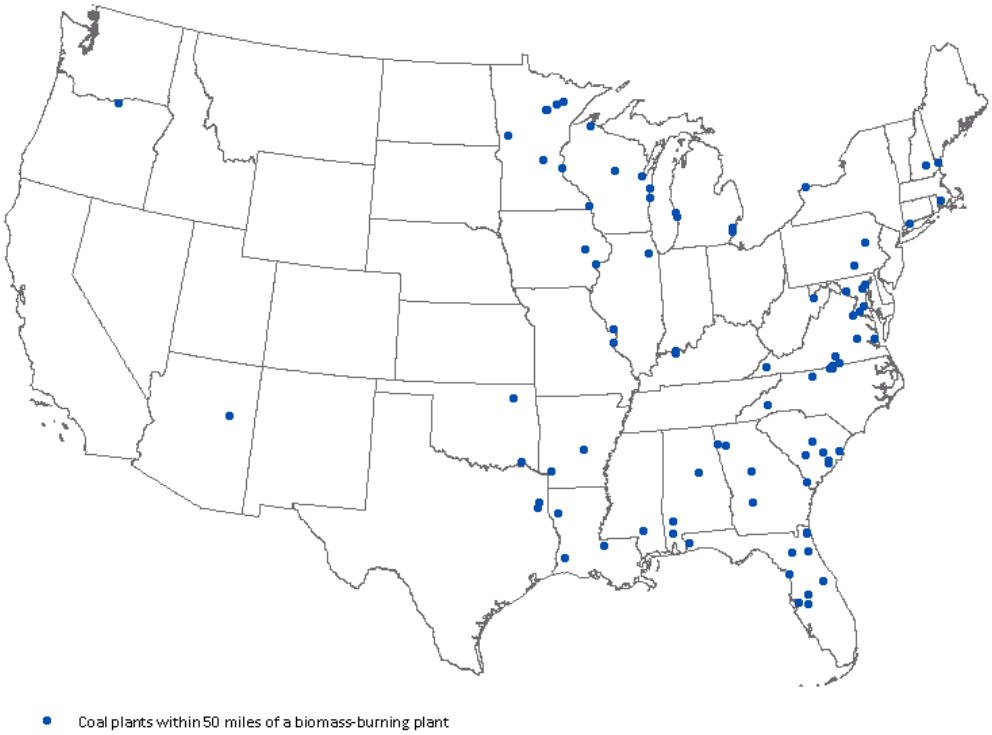
biomass supplies. The geographic range of coal-burning plants that co-fire biomass suggests that many plants that did not co-fire with biomass in 2017 are located close to plants that did burn biomass in 2017. This proximity suggests that biomass supply is available to those plants.

To approximate whether coal-burning plants have access to biomass supply, we use the 2017 Form EIA-923 data to identify the locations of biomass-burning plants. Figure 2 shows that these plants have a large geographic range, spanning 41 states, and suggesting widespread availability of biomass.

Figure 2. Biomass Plants, 2017

We use the list of plants that we identified as burning coal and calculate the closest distance to a biomass-burning plant. Figure 3 shows that 29 percent of coal-burning plants are located within 50 miles of a biomass-burning plant. This calculation suggests that biomass co-firing may be an option for a substantial number of coal-fired EGUs. We do not have data on biomass fuel costs, but the fact that many plants used biomass for electricity generation implies that the biomass supplies were cost effective for those plants.

Figure 3. Coal-Burning Plants in Proximity to Biomass Plants, 2017



We also find evidence that biomass supply is more than sufficient based on existing resources without the need to trigger new dedicated energy crops. FIA data on the availability of net woody biomass within fifty miles of a biomass-burning plant in eastern U.S. states shows that if all available woody biomass were used for electricity generation, it could have generated at least 151 million TWh of electricity nationally in 2015.[16] This is more than two times the 64 TWh of total biomass generation in 2015. Table 2 presents net electricity generation from biomass and net woody biomass supply for the eastern states for which we have supply data, showing that 27 of the 30 states had greater potential generation from woody biomass compared to actual total biomass generation in 2015. "Net" woody biomass describes the annual availability of fuel supply after accounting for harvest removal, removal due to land use change and mortality; estimates are the bone-dry (0 percent moisture) tons of annual wood that are available in the forest. This means that there is sufficient national biomass supply without the need to convert land to non-forest uses. These data on net woody biomass availability is based on the supply within 50 miles of a biomass-burning plant and only consider 30 eastern states, so total availability is likely to be higher.

[16] Heat content depends on species types. Our calculation is based on the assumption that 1 ton of moisture-free (bone dry) woody biomass can generate about 1 MWh of electricity in a conventional boiler system (https://ucanr.edu/sites/WoodyBiomass/newsletters/IG003_-_Woody_Biomass_Definitions_and_Conversions_Factors31510.pdf).

Table 2: Statewide Biomass Generation and Potential Generation from Woody Biomass, 2015

State	Net Electricity Generation from Biomass, MWh	Potential Generation from Available Net Woody Biomass, MWh	Percent Difference
AL	3,289	15,266	364%
AR	1,441	6,082	322%
CT	787	2,736	248%
DE	76	109	43%
FL	4,919	9,076	85%
GA	4,734	11,803	149%
IN	446	323	-28%
IA	258	-131	-151%
KY	441	3,345	658%
LA	2,705	6,530	141%
ME	3,153	5,393	71%
MD	514	1,138	121%
MA	1,167	2,729	134%
MI	2,485	6,532	163%
MN	1,806	3,028	68%
MS	1,507	12,616	737%
MO	129	907	603%
NH	1,624	1,791	10%
NJ	946	648	-31%
NY	2,241	2,915	30%
NC	2,589	15,314	491%
OH	799	1,268	59%
PA	2,404	5,160	115%
RI	211	488	131%
SC	2,289	8,896	289%
TN	1,004	3,442	243%
VT	465	1,773	281%
VA	4,144	13,209	219%
WV	5	2,454	48988%
WI	1,571	6,380	306%
National	**63,632**	**151,221**	**138%**

Note: Potential generation is based on net woody biomass availability within 50 miles of a biomass-burning plant. We convert from tons of bone-dry woody biomass to MWh based on the assumption that 1 ton of moisture-free (bone dry) woody biomass can generate about 1 MWh of electricity in a conventional boiler system (https://ucanr.edu/sites/WoodyBiomass/newsletters/IG003_-_Woody_Biomass_Definitions_and_Conversions_Factors31510.pdf).

Source: Data provided by Ram Dahal and Francisco Aguilar at the University of Missouri, collected from the US Department of Agriculture Forest Service Forest Inventory and Analysis National Program (FIA).