October 31, 2018

EPA Docket Center
U.S. EPA, Mail Code 28221T
1200 Pennsylvania Ave., NW
Washington, DC 20460

Submitted Electronically via Regulations.gov

Attn: EPA-HQ-OAR-2017-0355
RE: Comments of Environmental Defense Fund on EPA's 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, 83 Fed. Reg. 44,746 (Aug. 31, 2018).

On behalf of its over two million members and supporters, the Environmental Defense Fund ("EDF") submits the attached comments on the Environmental Protection Agency's ("EPA's" or the "Agency's") August 31, 2018, proposed rule to replace the Clean Power Plan ("CPP") with a far less protective guideline for carbon pollution from existing power plants; revise its framework regulations implementing section 111(d) of the Clean Air Act; and weaken New Source Review ("NSR") protections for modified power plants.[1] These comments are supplemental to five other comment letters that EDF is filing jointly with other public health and environmental organizations ("Joint Environmental Commenters"), together with a joint appendix of materials that are cited to in these comments or our joint comments.[2] EDF is also

[1] EPA, "Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program," 83 Fed. Reg. 44,746 (proposed Aug. 31, 2018) ("Proposed Rule" or "ACE").

[2] Joint Comments of Environmental and Public Health Organizations on the Best System of Emission Reduction and Other Issues, Doc. No. EPA-HQ-OAR-2017-0355 (Oct. 31, 2018); Joint Comments of Environmental and Public Health Organizations on the Regulatory Impact Analysis, Doc. No. EPA-HQ-OAR-2017-0355 (Oct. 31, 2018); Joint Comments of Environmental and Public Health Organizations on Proposed Revisions to Emission Guideline Implementing Regulations, Doc. No. EPA-HQ-OAR-2017-0355 (Oct. 31, 2018); Comments of Public Health and Environmental Organizations on the Proposed Amendments to the New Source Review Regulations, Doc. No. EPA–HQ–OAR–2017–0355; Comments of Environmental and Public Health Organizations Concerning Climate Science and Climate Change, Doc. No. EPA-HQ-OAR-2017-0355 (Oct. 31, 2018); Joint Appendix of Environmental and Public Health Organizations to Comments Regarding EPA's 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, Docket No. EPA-HQ-OAR-2017-0355 (Oct. 31, 2018) (submitted via flash drive delivered to EPA by Surbhi Sarang).

submitting a separate appendix of materials cited in this document.[3] In addition, four analyses are attached directly to this filing. These comments also build upon and reference the comments and materials filed by EDF in response to EPA's October 16, 2017 proposal to repeal the CPP outright[4]—all of which EPA has indicated are part of the administrative record for this Proposed Rule[5]—as well as comments submitted in response to the December 28, 2017 advance notice of proposed rulemaking.[6]

As we describe in detail in these filings, the Proposed Rule represents an appalling abandonment of EPA's legal and moral responsibility to protect Americans from the climate and health impacts of power plant pollution. Just weeks ago, thousands of the world's leading scientists issued an alarming report confirming that climate pollution from power plants and other sources is causing severe disruption of our climate; that manmade climate change is threatening the health, safety, and well-being of communities in the United States and across the globe in the form of more intense hurricanes, more frequent heat waves, rising sea levels, and longer wildfire seasons; and that the United States and other major emitting countries must take bold and immediate action to reduce climate pollution if we are to avoid even more devastating impacts.[7] Power plants are far and away the largest category of stationary sources contributing to harmful climate pollution, representing 29% of the United States' total greenhouse gas emissions in 2015.[8]

Rather than protect Americans from this threat, the Proposed Rule would take this country in precisely the wrong direction—exposing communities to *more* harmful carbon pollution and leading to more death and disease from soot and smog. The Proposed Rule would entirely discard the CPP, which establishes meaningful limits on carbon pollution based on cost-effective and common-sense techniques already being used by states and power companies to reduce pollution from existing power plants. In its place, the Proposed Rule would erect a radically weaker framework that fails to require that power plants achieve *any* particular level of pollution reduction by any particular deadline. And the Proposed Rule would introduce sweeping and unlawful regulatory changes that weaken long-standing Clean Air Act protections by allowing aging, dirty coal-fired power plants to increase pollution without installing modern pollution controls.

These harmful efforts to shield power plants from any meaningful obligation to reduce carbon pollution would come at the direct expense of the lives and health of American families and

---

[3] Appendix of Environmental Defense Fund to Comments Regarding EPA's 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, Docket No. EPA-HQ-OAR-2017-0355 (Oct. 31, 2018) (submitted via flash drive delivered to EPA by Surbhi Sarang).
[4] EPA, Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 82 Fed. Reg. 48,035 (proposed Oct. 16, 2017).
[5] ACE, 83 Fed. Reg. at 44,750.
[6] EPA, State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units: Advance Notice of Proposed Rulemaking, 82 Fed. Reg. 61,507 (Dec. 28, 2017).
[7] *See generally* Intergovernmental Panel on Climate Change, *Global Warming of 1.5ºC: Summary for Policymakers* (Oct. 2018), *available at http://report.ipcc.ch/sr15/pdf/sr15_spm_final.pdf*.
[8] EPA, "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," at 2-26 (Aug. 2018) ("ACE RIA").

communities. Relative to the CPP, EPA estimates that this proposal would lead to as much as 103 million tons of additional carbon pollution in 2030 alone.[9] Through 2030, the proposal would result in a *cumulative* increase of carbon pollution of approximately 863 million tons[10]—an amount greater than the individual annual emissions of all but eight of the world's countries.[11] At the same time, the proposal would increase emissions of sulfur dioxide and nitrogen oxides by as much as 72,000 tons and 53,000 tons in 2030, respectively[12]—leading to as many as 1,630 additional deaths from air pollution in 2030 and increased annual healthcare costs of as much as $10.6 billion.[13]

This deeply harmful proposal violates the Clean Air Act and rests on a fatally deficient legal and technical record. We urge Acting Administrator Andrew Wheeler to withdraw this proposal, and to instead move forward with protections that achieve the deep reductions in carbon pollution that the Clean Air Act requires and that are urgently needed to meet the threat of climate change. We summarize some of our principal objections to the proposal below.

1. EPA's Proposed Emission Guidelines Are Unlawful and Arbitrary.

EPA wrongly insists in the Proposed Rule—as it did in the October 2017 proposed repeal—that the CPP is unlawful and that the Agency has no choice but to withdraw it. As we explained at length in our comments on the proposed repeal and in these comments, EPA properly determined in the CPP that the "best system of emission reduction" ("BSER") for carbon pollution from existing power plants includes shifting generation from high-emitting power plants to low- and zero-emitting resources. This BSER fits well within the broad language of section 111; is consistent with the legislative history, structure, and purpose of the Clean Air Act; is supported by extensive administrative precedents, including other successful Clean Air Act programs that have relied upon generation-shifting to reduce emissions; reflects the day-to-day practices of power companies and the interconnected nature of the power sector; and best conforms to the factors EPA is required to consider (including cost and energy requirements) when designating a BSER under section 111(d).

None of the legal or technical objections that EPA raises either in the proposed repeal of the CPP or in this Proposed Rule have merit. For example, EPA claims that it lacks the expertise in energy systems to establish a BSER based on generation-shifting—ignoring that section 111 specifically directs EPA to consider the "energy requirements" associated with air pollution standards, and that EPA has consistently evaluated the energy system impacts of air pollution

[9] *Id.* at ES-7, ES-8 tbl. ES-5 (power sector emissions under Proposed Rule), 3-40tbl. 3-41 (power sector emissions under the Clean Power Plan implemented as contemplated in the 2015 RIA).
[10] ACE RIA (using IPM State-Level Emissions: Base Case (CPP) with EE and IPM State-Level Emissions: Illustrative 4.5 percent HRI at $50/kW modeling output files). The IPM State-Level Emissions modeling output files provide carbon dioxide emissions for years including 2021, 2023, 2025, and 2030. Carbon dioxide emissions for the years 2022, 2024, 2026, 2027, 2028, 2029 were linearly interpolated. Carbon dioxide emissions were then summed from 2021 through 2030 to arrive at cumulative emissions for both the Base Case (CPP) with EE case and the Illustrative 4.5 percent HRI at $50/kW case and the difference between both cumulative emissions was calculated.
[11] *See* World Resources Institute, CAIT Climate Data Explorer, http://cait.wri.org (last visited Oct. 31, 2018). (emissions data attached as an exhibit to these comments).
[12] ACE RIA 3-16 tbl. 3-7, 3-41 tbl. 3-42.
[13] ACE RIA at ES-13 tbl. ES-9.

standards for power plants going back to the 1970s.[14] EPA also claims, without any supporting evidence, that the CPP could pose an unacceptable "challenge" to the electric grid—even as the RIA for this Proposed Rule acknowledges that recent power sector trends have been consistent with the CPP, and that the CPP has become *more* cost-effective over time.[15]

Moreover, EPA's proposed replacement for the CPP flouts its obligation to designate the *best* system of emission reduction for existing power plants—one that achieves reductions in pollution "to the greatest degree practicable."[16] But rather than designate the "best system," the Proposed Rule simply presents a list of "candidate" heat rate improvement ("HRI") measures that states must consider in establishing standards for steam electric generating units ("EGUs"). This list does not even qualify as a "system," much less represent the "best" system for power plants. Indeed, the Proposed Rule finds that HRI would, at best, achieve trivial reductions in carbon pollution—and would actually incentivize highly-polluting coal power plants to operate *more*, such that the overall emission reductions from the Proposed Rule would amount to no more than 1 to 2 percent less than business as usual. Indeed, EPA's modeling indicates that in as many as 19 states, coal-fired power plants would emit *more* soot and smog-forming pollution than if EPA had simply not issued any emission guidelines at all.[17] It was for this very reason that EPA rejected as legally unsound a BSER consisting solely of HRI in the CPP. The Proposed Rule offers no rational justification for its departure from this well-reasoned conclusion.

EPA's proposal also fails entirely to require any reductions in carbon pollution from natural gas combined cycle ("NGCC") facilities, which account for approximately one-quarter of carbon pollution from the power sector and are responsible for a large and growing share of overall power generation. Whereas the CPP would have required these facilities to abide by meaningful limits on carbon pollution, this proposal would unlawfully leave them entirely unregulated.

EPA could have—and is legally required to—consider alternatives that achieve far greater pollution reduction at acceptable cost. Yet EPA has utterly failed to do that, even though the Agency itself collected extensive information on such alternatives during the CPP rulemaking process—and received further information from EDF and other commenters in response to the ANPR soliciting input on a replacement for the CPP. Here, we again provide extensive information on the availability, cost, and benefits of other approaches to setting guidelines for existing power plants—including emissions-reducing utilization; increased use of natural gas co-firing (or conversion to natural gas) at steam EGUs; carbon capture and sequestration ("CCS"); and options for reducing emissions from NGCC facilities. In the Proposed Rule, EPA rejects all of these options based either on completely arbitrary and extra-statutory limitations on what can constitute a "system of emission reduction," or on completely unsupported (and incorrect) claims that they are costly and infeasible. This cursory and blinkered rejection of alternative approaches does not even begin to satisfy EPA's legal obligation to select a "best" system of emission reduction that achieves maximum feasible control of harmful climate pollution.

---

[14] *See, e.g.*, *Sierra Club v. Costle*, 657 F.2d 298, 332-34 (D.C. Cir. 1981).
[15] ACE RIA at ES-7, 3-8.
[16] *See Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 434 n.14 (D.C. Cir. 1973).
[17] Rama Zakaria, *The Trump Administration's Clean Power Plan Replacement – For Many States, Worse than Nothing* (Sept. 14, 2018), http://blogs.edf.org/climate411/2018/09/14/the-trump-administrations-clean-power-plan-replacement-for-many-states-worse-than-doing-nothing/.

In addition to the arbitrary rationales EPA has provided for discarding the CPP and adopting HRI as the BSER, the proposed emission guidelines violate the Clean Air Act and depart from over forty years of administrative precedent by failing to provide *any* quantitative limits on pollution or deadlines for compliance—and by vesting states with virtually unfettered discretion to set their own standards of performance. Section 111 clearly requires EPA to ensure that "each State *shall* submit" a plan that establishes standards of performance "which reflect the degree of limitation achievable" through the BSER that EPA designates.[18] Although states may consider "remaining useful life" in applying such standards to individual sources, it is the states' responsibility under section 111—and EPA's legal obligation—-to ensure that each state plan establishes "standards of performance" that satisfy the statutory purpose of reducing pollution to the "greatest practicable degree."[19] *All* of EPA's past section 111(d) emission guidelines have fulfilled that obligation by specifying binding, quantitative emission limitations and compliance deadlines that reflect the degree of emission limitation achievable through the BSER.

The Proposed Rule provides no such emission limitations and compliance deadlines. Nor does it even provide any requirements for how states are to evaluate the feasibility and cost of the individual HRI technologies, tailor the application of standards to reflect remaining useful life, or otherwise ensure that their plans establish "standards of performance" that are consistent with section 111. To the contrary, the Proposed Rule encourages states to use remaining useful life, cost, and other factors to justify establishing the least stringent possible standards. This approach does not set adequate criteria to enable states to submit "satisfactory" plans that establish standards compliant with section 111, and it undermines the health and welfare protections that section 111(d) is intended to secure.

2. EPA's Revisions to the Section 111(d) Implementing Regulations Are Unlawful and Arbitrary.

EPA not only fails to provide emission limitations and compliance deadlines for carbon pollution from power plants, it also proposes that the same unlawful and arbitrary approach be extended to *all future* emission guidelines issued for other source categories under section 111(d) of the Clean Air Act. This departs from EPA's clear responsibility under the Clean Air Act—a responsibility it has recognized for over forty years—and completely fails to consider the harmful ramifications that would result for communities, for states, and even for industries subject to regulation. EPA's approach would give every state an incentive to set the least stringent standards possible, creating the very "race to the bottom" that the Clean Air Act was designed to avoid. And it would create enormous and unnecessary administrative burdens and regulatory uncertainty for states and industry.

EPA further proposes to dramatically extend the deadlines for states and EPA to implement future clean air protections under the Clean Air Act—allowing as long as six years after an emission guideline is issued before standards are put in place. EPA provides no satisfactory explanation as to why these delays are necessary.

[18] 42 U.S.C. § 7411(d)(1).
[19] *Essex Chem. Corp.*, 486 F.2d at 434 n.14.

3. EPA's Proposed Weakening of New Source Review Requirements Is Unlawful and Arbitrary.

The Proposed Rule would compound the harm associated with rolling back the Clean Power Plan by simultaneously weakening EPA's New Source Review regulations. For decades, this core Clean Air Act protection has ensured that power plants and other large industrial facilities install modern pollution controls when undertaking major modifications that could increase their emissions. Under the Proposed Rule, however, any power plant that undertakes a modification would be exempt from New Source Review so long as its *hourly* emissions do not increase over historic levels—even if the modification would result in the power plant running for many more hours in a given year and emitting significantly more air pollution.

This proposed NSR loophole is contrary to the text and structure of the Clean Air Act as well as judicial precedent, all of which make clear that NSR permitting is required for any modification that would result in an increase in "actual" emissions—measured in terms of annual air pollution burdens, not hourly emission rates. Indeed, the Proposed Rule would exempt even those modifications that increase annual emissions by an amount that would trigger NSR permitting if they came from a brand new source—an absurd result that underscores the extent to which EPA's proposed NSR revisions undermine the purpose and intent of the NSR program.

What is more, EPA has utterly failed to provide a legitimate or well-reasoned rationale for this harmful proposal. EPA claims that its proposed weakening of NSR is necessary in order to facilitate heat rate improvement projects that states may require under the proposed emission guidelines. But the Agency provides *no* analysis of which plants might incur NSR-related costs as a result of the emission guidelines, what those costs might be, or why EPA thinks those costs are prohibitive—rather than the fulfillment of Congress's intent that existing sources install best available pollution controls when they undertake a modification that will increase emissions of dangerous emissions. Moreover, the Agency fails to consider mechanisms available under the *current* NSR regulations that would mitigate or avoid these costs. And the proposed NSR provisions arbitrarily apply not just to modifications resulting from the proposed emission guidelines, but to *any* modification undertaken at *any* power plant—even power plants not covered by the emission guidelines.

4. EPA Has Failed to Adhere to Procedural Requirements Intended to Protect the Integrity of the Rulemaking Process.

EPA received an outpouring of requests for additional time and opportunities for comment from numerous state legislators, regulators, and state attorneys general; industry associations; environmental and public health organizations; members of Congress; and other stakeholders. Yet the Agency has provided only 61 days for public comment on this complex and highly consequential rulemaking that would harm Americans' health and damage their environment for decades to come—and just *one* opportunity for a public hearing. In addition, EPA has failed to provide *any* documentation of the "review" that it purportedly conducted of the CPP in response to President Trump's Executive Order 13,783,[20] even though that "review" supposedly provided the impetus for this entire rulemaking and the Clean Air Act requires all such materials to be

[20] 83 Fed. Reg. at 44,749.

provided for public comment.[21] Furthermore, EPA has failed to abide by applicable requirements to seek input from state, local, and tribal officials, undermining the ability for these important stakeholders to provide input into the development of this misguided proposal. Finally, development of this proposal has been impermissibly tainted by key portions of the proposal's origins in former Administrator Scott Pruitt's compromised Clean Power Plan repeal proposal.

We appreciate your careful consideration of these comments. Please direct any inquiries regarding these comments to Tomás Carbonell, Director of Regulatory Policy at EDF, at tcarbonell@edf.org or 202-572-3610.

Respectfully submitted,

Sean Donahue
Susannah Weaver
Donahue, Goldberg & Weaver, LLP
1111 14th St., NW
Suite 510A
Washington, DC 20005
Counsel for Environmental Defense Fund

Vickie Patton
Lance Bowman
Tomás Carbonell
Ben Levitan
Martha Roberts
Surbhi Sarang
Rama Zakaria

Environmental Defense Fund
1875 Connecticut Ave., NW,
Suite 600
Washington, DC 20009

[21] 42 U.S.C. § 7607(d)(3) ("All data, information, and documents referred to in this paragraph on which the proposed rule relies shall be included in the docket on the date of publication of the proposed rule.").

Comments of Environmental Defense Fund on
EPA's 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, 83 Fed. Reg. 44,746 (Aug. 31, 2018).

Table of Contents

I. EVEN UNDER EPA'S FLAWED INTERPRETATION OF BSER, THE AGENCY SHOULD HAVE CONSIDERED AND INCLUDED ADDITIONAL POLLUTION REDUCTION MEASURES.

As explained in our comments on the proposed repeal of the Clean Power Plan ("EDF Repeal Comments")[22] and in the Joint Environmental Comments on BSER Issues for this Proposal, EPA's conclusion that it must abandon the CPP's[23] best system of emission reduction ("BSER") is unlawful and arbitrary. Because the CPP BSER reflects a permissible and reasonable interpretation of the Clean Air Act, and achieves far greater reductions than the Proposed Rule[24] at reasonable costs, EPA has not provided a reasoned justification for discarding the CPP BSER in favor of its proposed approach.

Even under EPA's proposed re-interpretation of the statute, however, the Agency's proposed determination that heat rate improvement ("HRI") measures constitute the "best system of emission reduction" for carbon dioxide ("CO_2") from existing electric generating units ("EGUs") arbitrarily overlooks numerous on-site measures that are capable of achieving substantial emission reductions. As discussed below, these measures include emission-reducing changes in the utilization of EGUs; natural gas co-firing and conversion; carbon capture and sequestration; renewable energy integration; and changes in coal rank and coal preparation. Individually and in combination, these measures would yield greater emission reductions than HRI and at costs that would not be exorbitant or threaten the industry. Yet EPA has utterly failed to even consider many of these options (even though they were included in comments on the December 2017 Advance Notice of Proposed Rulemaking[25] ("ANPR")), and dismisses carbon capture and sequestration ("CCS") and natural gas co-firing without any detailed assessment of cost, feasibility, or emissions impacts.

This scant consideration of alternatives that have been thoroughly presented to EPA in prior comments (and that EPA itself has favorably evaluated in prior rulemakings) is patently arbitrary, and does not satisfy EPA's obligation to select the "best" system of emission reduction—even under the Agency's cramped and unlawful proposed interpretation. EPA must thoroughly consider all available options in light of the statutory factors in Clean Air Act ("CAA") section 111(a)(1),[26] including the measures described below, and ensure that whatever "best system" it adopts fulfills the statutory imperative to establish carbon pollution limits that

[22] "Comments of Environmental Defense Fund on EPA's Proposed Rule: Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," Docket ID No. EPA-HQ-OAR-2017-0355-20949 (Apr. 26, 2018).
[23] EPA, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,662 (Oct. 23, 2015) ("Clean Power Plan" or "CPP").
[24] EPA, Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program, 83 Fed. Reg. 44,746 (proposed Aug. 31, 2018) ("ACE" or "Proposed Rule").
[25] EPA, State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units: Advance Notice of Proposed Rulemaking, 82 Fed. Reg. 61,507 (Dec. 28, 2017) ("ANPR"); *see also* "Comments of Environmental Defense Fund on EPA's Advance Notice of Proposed Rulemaking on State Guidelines for Greenhouse Gas Emissions from Existing Sources" at 48, Docket ID No. EPA-HQ-OAR-2017-0545-0297 (Feb. 26, 2018) ("EDF ANPR Comments").
[26] 42 U.S.C. § 7411(a)(1).

achieve maximum feasible emissions control and adequately addresses the urgent threat of climate change.[27]

A. Emissions-Reducing Utilization

As environmental organizations have urged in previous comments,[28] EPA should have considered a BSER of emissions-reducing utilization when developing an emission guideline for existing power plants. Under this approach, the Agency would determine an emission limitation for the category or subcategory within each state. This limitation would reflect the potential for the grid to deploy lower-emitting generation sources (renewable energy and natural-gas fired combined cycle plants) if higher-emitting sources are constrained under the factors set forth in CAA section 111(a)(1). This section of the comments discusses the legal justification for, and feasibility of, such an approach. Because it is consistent with section 111, "adequately demonstrated," and better fulfills the factors EPA must consider when designating a "best system" under section 111(a)(1) than the current proposal, EPA arbitrarily and unlawfully ignored emissions-reducing utilization in the ACE proposal.

1. Emissions-reducing utilization fits within EPA's interpretations of the term "best system of emission reduction" in both the CPP and the ACE proposal.

In the CPP, EPA concludes that the plain meaning of the term "best system of emission reduction" is "deliberately broad and is capacious enough to include actions taken by the owner/operator of a stationary source designed to reduce emissions from that affected source, including actions that may occur off-site and actions that a third party takes pursuant to a commercial relationship with the owner/operator, so long as those actions enable the affected source to achieve its emission limitation."[29] Now, EPA proposes to interpret "BSER" much more narrowly, to include only "measures that can be applied to or at an individual stationary source" and that are "based on a physical or operational change to a building, structure, facility or installation at that source rather than measures the source's owner or operator can implement at another location."[30] Although EPA's conclusion that the CPP exceeds the Agency's authority is unlawful and arbitrary for reasons discussed elsewhere in these and previous comments, emissions-reducing utilization comfortably fits within either interpretation of "BSER."

Emissions-reducing utilization may qualify as the BSER under EPA's admittedly novel and vague[31] interpretation because it 1) is a system;[32] 2) is "applied to or at" a source;[33] 3) is based

---

[27] *See infra* section IV.
[28] "Comments of Sierra Club, the Center for Biological Diversity, and Earthjustice on State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units: Advance Notice of Proposed Rulemaking," at 24-30, Docket ID No. EPA-HQ-OAR-2017-0545-0256 (Feb. 26, 2018); EDF ANPR Comments at 60 (Feb. 26, 2018).
[29] CPP, 80 Fed. Reg. at 64,761.
[30] ACE, 83 Fed. Reg. at 44,752.
[31] As some commenters on EPA's proposed repeal of the CPP have noted, the reasoning behind or scope of the Agency's new interpretation is far from coherent. Our attempt to analyze various possible aspects of the interpretation by no means suggests that EPA has adequately delineated its contours.
[32] ACE, 83 Fed. Reg. at 44,755.
[33] *Id.* at 44,752.

on a "physical or operational change" at the source;[34] and 4) results in an emission limitation "achievable" by the source.[35]

a. The term "system" encompasses emissions-reducing utilization.

Limiting the amount that a power plant runs qualifies as a "system" of emission reduction. In the preamble to the CPP, EPA notes that "[t]he ordinary, everyday meaning of 'system' is a set of things or parts forming a complex whole; a set of principles or procedures according to which something is done; an organized scheme or method; and a group of interacting, interrelated, or interdependent parts."[36] Thus, EPA has concluded, the phrase "system of emission reduction" broadly means "a set of measures that work together to reduce emissions."[37] Placing a flexible limit on the utilization of a generator qualifies as a system under this definition.

The legislative history of the CAA Amendments of 1977 supports the conclusion that BSER need not be technological and may comprise any steps that a source takes to curb emissions. While the 1977 amendments limited the BSER for new sources to technological controls,[38] Congress was clear that systems for existing sources would not be limited to technological measures. The House committee report indicates Congress intended that existing electric utility generators be able to comply with standards of performance by combusting low-sulfur coal, a non-technological compliance method.[39] The conference report reiterates that standards for existing sources were to be based on systems that were "not necessarily technological."[40] In 1990, Congress removed the "technological" requirement for systems of emission reduction applicable to new sources, expanding the more flexible approach to new sources as well and further reinforcing that a system of emission reduction under Section 111 need not be technological. Just as switching to a cleaner fuel is a non-technological control that qualifies as a "system" under section 111, using less fuel through reducing generation as compared to business as usual also fits within the scope of this term.

The legislative history of the 1970 Clean Air Act also confirms that Congress intended the concept of a "system" to be expansive and to consider operational techniques or approaches that would prevent pollution—a description that certainly applies to emissions-reducing utilization. As the final CPP observed, the committee report for the Senate bill that eventually became section 111 of the Clean Air Act explained that "performance standards should be met through

[34] *Id.*
[35] *See* EPA, Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 82 Fed. Reg. 48,035, 48,039 (Oct. 16, 2017) ("Proposed Repeal") (citing CPP, 80 Fed. Reg. at 64,762).
[36] CPP, 80 Fed. Reg. at 64,720 (citing Oxford Dictionary of English (3d ed.) (2010)).
[37] *Id.*
[38] *See* Pub. L. No. 95-95, § 109(c)(1)(A), 91 Stat. 700 (1977) (requiring standards of performance for new sources to reflect the degree of emission limitation achievable "through the application of the best technological system of continuous emission reduction").
[39] *See* H.R. Rep. No. 95-294, at 186 (1977).
[40] H.R. Rep. No. 95-564, at 129 (1977) (Conf. Rep.). Another instance of the term "system," although enacted subsequently to section 111, indicates Congress's expansive understanding of this word. *See* 42 U.S.C. § 7511b(e)(1)(A) (defining "best available controls" for volatile organic compounds to include "systems or techniques, including chemical reformulation, product or feedstock substitution, repackaging, and directions for use, consumption, storage, or disposal").

application of the latest available emission control technology or through other means of prevention or controlling air pollution," and that the term "standard of performance" would refer to "the degree of emission control which can be achieved through process changes, operation changes, direct emissions control, or other methods."[41] The conference agreement on the Clean Air Act Amendments of 1970 likewise explained that section 111 "authorizes regulations to require that new major industry plants such as power plants, steel mills, and cement plants achieve a standard of emission performance based on the latest available control technology, processes, operating methods, and other alternatives."[42] Thus, in crafting section 111, Congress clearly intended that systems of emission reduction embrace methods *other* than "control technology," including "operation changes" or "operating methods" that prevent pollution. Emissions-reducing utilization is consistent with that intent.

b. Emissions-reducing utilization is applied to and at power plants and is based on a physical or operational change at the source.

The act of limiting the amount that an electric generator runs based on its emissions takes place at the electric generator. Any limit on generation must result from a physical change at the unit—turning it down or up to match the emissions constraint. When hours of operation change at the plant, emissions at the plant respond accordingly. The source-specific nature of a BSER of emissions-reducing utilization, whether or not state standards include trading of credits as a compliance mechanism, ensures emissions reductions from the affected sources. Emissions-reducing utilization falls well within EPA's new interpretation that requires the BSER to be "applied to or at" a source.

c. Emissions-reducing utilization is "achievable" by affected sources.

Emissions-reducing utilization is an "achievable" system of emission reduction because affected sources may themselves take action to implement it, which is a statutory requirement that EPA identifies in the CPP.[43] Owners or operators of power plants can and do control total generation by communicating permit limitations to those authorities or incorporating compliance costs into their bids if in a market-based grid region.[44] In the context of a BSER that contemplates all high-emitting EGUs will engage in emissions-reducing utilization by limiting their output in a manner that can be cost-effectively accommodated by the grid, both individual EGU emissions and overall emissions from the source category will decrease.[45] Accordingly, a BSER of emissions-reducing utilization is a means of reducing emissions that is achievable by the affected sources.

---

[41] CPP, 80 Fed. Reg. at 64,764 (citing S. Rep. No. 91–1196, at 15–16 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 415–16).
[42] *Id.* (citing Sen. Muskie, S. Consideration of H.R. Conf. Rep. No. 91–1783 (Dec. 17, 1970), 1970 CAA Legis. Hist. at 130).
[43] *See id.* at 64,762 ("[A] 'system of emission reduction' for purposes of CAA section 111(d) means a set of measures that source owners or operators can implement to achieve an emission limitation applicable to their existing source. In contrast, a 'system of emission reduction' does not include actions that only a state or other governmental entity could take that would have the effect of reducing emissions from the source category, and that are beyond the ability of the affected sources' owners/operators to take or control.").
[44] *See id.* at 64,781.
[45] *See id.* at 64,726; *id.* at 64,731; *see also* ICF, *Assessing Effects on the Power Sector of Greenhouse Gas Emission Standards* (2018) (attached).

The specific attributes of the electric grid make a BSER of emissions-reducing utilization uniquely appropriate when regulating climate pollution from existing power plants. First, electricity on the grid is perfectly fungible, meaning that electricity generated by various sources is indistinguishable (in contrast to other commodity markets where substitutes have similar, but not identical, characteristics).[46] Second, other producers *must* be ready to compensate for decreased generation at a source, making redispatch a normal and essential practice in this "real-time" market.[47] Finally, power companies specialize in the provision of power generation and/or delivery of reliable electricity, and as such it is commonplace for companies to own or purchase electricity from multiple types of generation, unlike other firms that may specialize in a particular method of production of a distinct product.[48] These unique aspects of the power sector show why a system of emissions-reducing utilization is distinctively appropriate to mitigate emissions in this particular sector and is readily implementable by covered sources.[49]

As EPA concluded in the CPP, and as our comments and the Joint Environmental Comments on BSER and Other Issues argue, emissions-reducing generation is also fully consistent with current trends in the power sector and "can be accommodated without significant cost or disruption."[50] Below, we further demonstrate that emissions-reducing generation can be implemented without significant cost or reliability concerns through a series of dispatch modeling scenarios conducted using IPM. These modeling results show that emissions-reducing utilization can be implemented (with or without trading) in a way that achieves far greater emission reductions than either this Proposed Rule or the CPP, without unreasonable cost, and while meeting projected electricity demand and maintaining resource adequacy in all regions of the country.

2. Emissions-reducing utilization meets the BSER criteria.

Emissions-reducing utilization qualifies as the BSER because it achieves maximum emission reductions at a cost that the industry can bear, does not produce significant countervailing non-air-quality health and environmental impacts, and provides flexibility such that any reliability concerns can be addressed.[51] Although EPA has discretion in balancing the statutory factors,[52] emissions-reducing utilization is clearly superior to the optional list of HRI measures the Agency has proposed to identify as the BSER, as measured by any of these criteria. It was therefore

[46] *See* Comment by Electricity Grid Experts on the Proposed Repeal of the CPP at 3-4, Docket ID No. EPA-HQ-OAR-2017-0355-20922 (Apr. 25, 2018).
[47] *See id.* at 4.
[48] *Id.* at 6, 16.
[49] *See* EPA, Legal Memorandum Accompanying Clean Power Plan for Certain Issues, at 119 n.348 ("CPP Legal Memorandum"); *see also* CPP, 80 Fed. Reg. at 64,782.
[50] CPP, 80 Fed. Reg. at 64,780. *See also id.* at 64,782 (Mechanisms are in place in both regulated and deregulated electricity markets to assure that substitute generation will become available and/or steps to reduce demand will be taken to compensate for reduced generation by affected EGUs. As a result, reduced generation will not give rise to reliability concerns or have other adverse effects on the utility power sector and are of reasonable cost for the affected source category and the nationwide electricity system."); Joint Environmental Comments on BSER and Other Issues § IV.D.1.b.
[51] 42 U.S.C. § 7411(a)(1).
[52] *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) ("Because section 111 does not set forth the weight that be should [sic] assigned to each of these factors, we have granted the Agency a great degree of discretion in balancing them.").

arbitrary and unlawful for the Agency not to consider this system when evaluating the universe of systems that fall within its new interpretation of "BSER," and it would be arbitrary and unlawful for the Agency to finalize a BSER that fails to provide equivalent emission reductions to emissions-reducing utilization.

Emissions-reducing utilization is a highly cost-effective system that can achieve substantial reductions in emissions from the regulated source category. Because it has relatively low costs and harnesses the normal operations of the power sector, emissions-reducing utilization has been commonly used within the power sector and by state and federal pollution-abatement programs.[53] When examining recent emissions reductions, EPA concluded that they have been "the result of industry trends away from coal-fired generation and toward low- and zero-emitting sources (*i.e.*, natural gas and renewable sources) that can produce the same electricity product as coal, but with 59 to 100% fewer CO_2 emissions."[54] These industry trends demonstrate that reducing utilization of carbon-intensive resources is economical at average historical levels of deployment of renewables and ramping up of NGCC plants. The costs of this BSER, if implemented, would therefore be reasonable—far from imperiling an industry that has already widely adopted the approach.[55]

If trading is allowed as one means of implementing emissions-reducing utilization (in which case EPA would need to take into account the advantages of trading when calculating the emissions reductions achievable through this system), this BSER will be even more cost-effective. With emissions trading in a mass-based program, the least efficient plants are more likely to reduce generation first because their reductions will make available more allowances than reductions from lower-emitting plants. Additionally, all else being equal, less-efficient units will have higher marginal fuel costs per unit of electricity delivered to the grid, further incentivizing reductions at the least-efficient plants. A system that allows market forces to drive emission reductions across the fleet of power plants will secure pollution abatement with the lowest costs, supporting its identification as the BSER.

Some have argued previously that a BSER that results in some units increasing their emissions is necessarily flawed. However, there is nothing unusual or impermissible about this result so long as the BSER for each category or subcategory achieves maximum feasible reductions such that overall emissions decrease to the greatest extent feasible. In the context of emissions reducing utilization, the increase in utilization of NGCC units is a consequence of the BSER's application to steam units. EPA must, in evaluating the statutory requirements that the BSER be adequately demonstrated and to consider energy requirements, take into account the implications for NGCC utilization that result from the steam-unit BSER when quantifying what the application of emissions reducing utilization to NGCC units can deliver in an emission limitation. The NGCC emission limitation still reflects, however, the potential to reduce NGCC utilization to the extent

[53] *See* CPP, 80 Fed. Reg. at 64,664; *see also* CPP Legal Memorandum at 39; *id.* at 93-95 (discussing integration of renewable energy and energy efficiency into state implementation plans for NAAQS); Final Br. of Intervenors Calpine Corp. *et al.*, D.C. Cir. No. 15-1363, at 2-3 (filed Apr. 22, 2016).

[54] EPA, "Basis for Denial of Petitions to Reconsider and Petitions to Stay the CAA section 111(d) Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units," Appendix 2 at 8-9 (Jan. 11, 2017) ("CPP Reconsideration Denial").

[55] *See Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975) (admonishing against costs under a section 111 rule that would be "greater than the industry could bear and survive").

that the grid can deliver renewable energy to supplant it. Just as with any emission standard, the units subject to each standard are required to remain below the level of the standard—regardless of whether the unit was historically below or above the level at which the regulatory standard is set.

Emissions-reducing utilization is also an "adequately demonstrated" system of emission reduction. The power sector has a long history of meeting emissions limitations through changes in utilization. As EPA notes in the CPP, power plants have accepted limits on their operating times or capacity factors to comply with other CAA requirements, such as implementing requirements for best available retrofit technology ("BART") or best available control technology ("BACT").[56] Similarly, EPA premised the emissions caps in the Cross-State Air Pollution Rule and the NO_x SIP Call in part on the assumption and expectation that EGUs would change their levels of utilization as a cost-effective means of reducing emissions.[57] It would be arbitrary for EPA to conclude that emissions-reducing utilization is not an available, effective means of reducing emissions of air pollutants when faced with numerous examples of compliance with Clean Air Act requirements using this mechanism.[58]

In addition, states and utilities have long been scaling back generation from higher-emitting power plants to meet pollution-reduction goals and requirements—demonstrating that such a regulatory approach is effective and feasible.[59] Indeed, power-company intervenors in the CPP litigation supported the CPP's use of generation-shifting as part of the BSER, which inherently involves reducing utilization of higher-emitting units. They argued:

> Electricity providers have been shifting generation among affected units and to zero-emitting sources as a means of achieving emission reductions for decades, as these strategies achieve greater reductions at lower cost than by relying on control technology alone. . . . Comments of Calpine Corporation, Los Angeles Department of Water and Power, National Grid, Seattle City Light, et al., EPA-HQ-OAR-2013-0602-23167, at 9 (JA001405) ("EPA's approach . . . reflects the essence of the way the electric industry operates . . . fully consistent with our companies' successful practices."). In fact, generation shifting is itself "business-as-usual" within the power sector and the ordinary means by which supply and demand are instantaneously matched throughout the interconnected electricity grid and balancing authorities and utilities make dispatch decisions to deliver power at least-cost to consumers. . . . By largely following existing trends that are causing generation shifts towards lower-emitting sources and by requiring reductions at no greater pace than they are already being achieved by many states and power companies, the Rule's formulation of the best system of emission reduction is reasonable and consonant with the practical realities of how the electricity grid is operated today.[60]

---

[56] *See id.* at 64,780-81; *see also* CPP Legal Memorandum at 72-81 (listing examples).
[57] *See* CPP Legal Memorandum at 82, 95-99.
[58] *Cf. New York v. EPA*, 443 F.3d 880, 888 (D.C. Cir. 2006) (holding EPA to its historical practice of treating equipment replacements as "physical changes" that could require new source review under the CAA).
[59] *See* CPP, 80 Fed. Reg. at 64,664; *see also* CPP Legal Memorandum at 93-95 (discussing integration of renewable energy and energy efficiency into state implementation plans for NAAQS).
[60] Final Br. of Intervenors Calpine Corp. *et al.*, D.C. Cir. No. 15-1363, at 2-3 (filed Apr. 22, 2016).

State intervenors, for their part, noted:

> State Intervenors were uniquely positioned to inform EPA's [BSER] determination because they have years of direct experience reducing power-plant carbon-dioxide emissions. . . . Encouraging [generation] shifts, among other steps, helped [Regional Greenhouse Gas Initiative ("RGGI")] states reduce carbon pollution from the power sector by over forty percent between 2005 and 2012. Other programs in Minnesota and California have also led plants to make meaningful reductions to greenhouse-gas emissions through some of the same measures EPA included in the "best system" here.
>
> The experience of power plants in our States has shown that these reductions in carbon-dioxide emissions can be achieved without impeding economic growth or threatening grid reliability. Indeed, State Intervenors' carbon-reduction initiatives have delivered significant economic benefits. For example, in RGGI's first three years, participating States realized $1.6 billion in net economic benefits, largely from reduced energy bills for consumers.[61]

These statements by power companies and states support the conclusion that limiting generation at higher-emitting existing power plants is an adequately demonstrated means of achieving emission reductions.

Finally, as discussed in the next section, the pollution reductions that emissions-reducing utilization can achieve are far greater than those EPA projects will result from the "illustrative scenarios" in its Regulatory Impact Analysis ("RIA") for ACE. This implicit BSER factor[62] is the most important, as it reflects the overriding purpose of section 111 to abate the harms of dangerous air pollution.[63] In light of the potential air-quality benefits and the cost-effectiveness of the approach, emissions-reducing utilization is far superior to the system that EPA has outlined. The Agency must therefore withdraw the ACE proposal and issue a new proposal that reflects the maximum feasible emission reductions documented by the modeling results presented below.

3. <u>Emissions-reducing utilization is feasible and cost-reasonable.</u>

In this section of our comments, we discuss dispatch modeling that EDF commissioned from ICF International, Inc. ("ICF") that demonstrates the feasibility and cost-reasonableness of emissions-reducing utilization as a system of emission reduction. To calculate feasible and effective levels of emissions-reducing utilization for purposes of the model, we have used current generation from steam EGUs and natural gas combined cycle combustion turbines ("covered sources"), current emissions from covered sources, and the projected availability of lower- or non-emitting generation resources. In general, we calculated available replacement generation at the level of the interconnection, applied that generation to fossil-fuel-fired fleets within the same interconnection, converted the results to regional emissions from each fleet, and then apportioned

---

[61] Br. for States and Municipal Intervenors, D.C. Cir. No. 15-1363, at 27-28 (filed Apr. 22, 2016).
[62] *See Sierra Club v. EPA*, 657 F.2d 298, 326 (D.C. Cir. 1981).
[63] *See* 42 U.S.C. § 7411(b)(1).

the emissions to the fleet in each state based on their current and expected generation levels. Individual sources may also be given a mass emissions limit by applying the statewide percentage reduction or increase in emissions from the fleet to each unit, where possible given the unit's current and available utilization. For a detailed explanation of the calculations used in our target setting, see "Addendum: Emissions-Reducing Utilization Calculation Methodology" at the end of this document.

Using the detailed approach laid out in the Addendum, we arrived at the national-level emissions-reducing utilization emission limits shown in Table 1 for existing fossil steam, NGCC, and combined fossil steam and NGCC EGUs from 2022 through 2030.[64] Table 1 also includes estimates for emission limits on new sources based on the Energy Information Administration's ("EIA") 2018 Annual Energy Outlook ("AEO") load growth projections.[65]

Table 1: National-Level Emissions-Reducing Utilization Emission Limits on Existing Fossil Steam and NGCC EGUs (million short tons CO_2)[66]

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Fossil Steam	1,109	980	847	708	606	577	558	539	519
NGCC	570	605	641	679	703	697	687	677	668
Fossil Steam + NGCC	1,679	1,585	1,488	1,387	1,309	1,274	1,245	1,216	1,187
New Sources	28	31	34	37	39	50	65	78	86

Table 2 below lists five illustrative policy cases we developed to test the feasibility and cost-reasonableness of emissions-reducing utilization as an approach to determining the BSER.[67] Our policy cases incorporate a range of assumptions regarding how emissions averaging or trading could be reflected in the BSER. In policy case 1 (PC1) and policy case 2 (PC2), we assume that EPA would establish distinct emission limitations for two subcategories of units (fossil steam EGUs and natural gas combined cycle combustion turbines), consistent with EPA's prior subcategorization approach. These emission limitations would take the form of state-wide emission caps for each subcategory, which would presume the availability of intrastate emissions trading among sources within each subcategory (but not across subcategories). PC1 is distinct from PC2 in that PC1 includes a separate limit on emissions of CO_2 from new EGUs. This new source cap is designed to ensure that the scenario faithfully reflects the BSER by preventing

---

[64] We estimated incremental renewable energy replacement generation of 558 GWh by 2030—equivalent to roughly 1,186 TWh of total renewable generation in 2030. As described in the Addendum, this is a conservative estimate based on average annual historic renewable technology capacity deployments. More realistic incremental renewable energy potential based on maximum historic renewable technology capacity deployments would be closer to 828 GWh by 2030—equivalent to roughly 1,456 TWh total renewable generation in 2030. As also described in the Addendum, we used a conservative 6% increase in NGCC replacement generation to reach 75% net summer capacity factor based on the average annual historic increase in natural gas generation.

[65] Incremental generation needed for each interconnection to satisfy projected load growth from 2016 baseline levels was calculated using 2016 historical sales adjusted to account for an average transmission loss factor of 7.51% and generation from under construction facilities included in the 2016 baseline was subtracted. For state-level emission limits on new sources, the incremental remaining generation is apportioned to states on the basis of each state's 2016 share of the interconnection's existing coal and NGCC generation total and converted to emission limits using the New Source Performance Standard emission rate for NGCC of 1,030 lbs/MWh.

[66] *See* Addendum for detailed emissions-reducing utilization approach.

[67] The BSER will take different forms depending on the level of regulation—e.g., category, subcategory, or facility.

existing EGUs (particularly NGCC) from reducing utilization based on the availability of new NGCC (which is not part of the BSER). Our other policy cases did not include a cap on new sources because PC1 demonstrates the feasibility and cost-reasonableness of the fully implemented BSER.

Policy case 4 (PC4) would assume a greater degree of trading by establishing state-wide "combined" caps that allow for unrestricted intrastate trading between fossil steam EGUs and natural gas combined cycle combustion turbines. In PC4, EPA's emission limitation would thus apply to a single source category consisting of all fossil EGUs, because the underlying "best system of emission reduction"—emissions-reducing utilization—is used to calculate the potential for emission reductions across the regulated sources and the combined cap with trading delivers the emission reductions at lower cost. PC4 also recognizes that including all fossil EGUs in a single source category would be appropriate because emissions-reducing utilization can be implemented in a similar way at both steam EGUs and NGCC.[68] In PC1, PC2, and PC4, states could (but would not be required to) establish a standard of performance for each covered EGU that would take the form of a requirement to emit no more carbon dioxide in a given year than is permitted by the amount of allowances the covered EGU retires—consistent with the flexibilities that we have considered in outlining the BSER.

Incorporating emissions trading into the reduced utilization BSER in this way is lawful and reasonable for all the reasons EPA identified in the CPP,[69] and is consistent with prior Clean Air Act rules that assume some degree of trading in determining the stringency of standards.[70] Nevertheless, we have also included an additional policy case (PC3) that demonstrates that emissions-reducing utilization is a viable BSER even *without* assuming or allowing emissions trading across facilities.[71] In PC3, each power plant (incorporating all covered EGUs at a single facility) is assumed to be subject to an individual limit on utilization, with no flexibility to exceed that constraint by trading with other covered sources. This approach is consistent with the proposed interpretation of section 111 in the Proposed Rule that precludes averaging and trading outside of the EGUs located at a single facility.

Lastly, we have included a policy case (PC5) that demonstrates the extent to which a broader range of compliance flexibilities—including demand-side energy efficiency and interstate trading—would affect the emission reduction benefits, energy impacts, and compliance costs of an emission guideline based on the BSER reflected in PC4. Because it includes a broad range of compliance flexibilities, PC5 does not directly represent the projected outcome of emissions-reducing utilization by itself. However, PC5 represents what the benefits of an emission guideline based on emissions-reducing utilization would likely be in practice, under the reasonable assumption that states and power companies would utilize all the compliance flexibilities that would be available to them under this framework.

---

[68] *See Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) (upholding EPA's refusal to subcategorize under section 111(b) where the relevant "best system" was not dependent upon boiler design or fuel type).

[69] 80 Fed. Reg. at 64,733-35.

[70] *See, e.g.*, Richard L. Revesz, Denise A. Grab, and Jack Lienke, *Familiar Territory: A Survey of Legal Precedents for the Clean Power Plan*, 46 ELR 10190, 10191-93 (2016).

[71] Emission limits derived for PC3 were slightly adjusted to ensure no individual NGCC unit exceeds 75% net summer capacity factor or its historic baseline capacity factor, whichever is higher.

Table 2: Policy Case Descriptions

PC1	Separate mass-based emission limits on existing fossil steam fleet and NGCC EGU fleet at the state level. No trading across subcategories or states and no banking. Mass-based emission limit on new sources at the state level.
PC2	Separate mass-based emission limits on existing fossil steam fleet and NGCC EGU fleet at the state-level. No trading across subcategories or states and no banking.
PC3	Plant-level emission limits on existing fossil steam and NGCC EGUs. No trading between plants or across states and no banking.
PC4	Combined emission limit on existing fossil steam and NGCC EGU fleet at the state level. No trading between sources in different states and no banking.
PC5	Combined emission limit on existing fossil steam and NGCC EGU fleet at the state level. Full national trading but no banking. 1% Incremental EE allowed for compliance.

All policy cases were modeled by ICF using ICF's Integrated Planning Model ("IPM").[72] The business-as-usual ("BAU") base case that ICF used is the NRDC BAU No CPP base case, which is consistent with EPA IPM v5.16/EPA IPM v6 assumptions.[73] In modeling the mass-based emission caps in cases PC1-PC4, ICF also "turned off" the ability of EGUs to comply using any measures other than changes in utilization. Table 3 summarizes ICF's modeling results across all policy cases in 2030.

Table 3: ICF Modeling Results – Emission Abatement and Abatement Costs Across All Policy Cases in 2030[74]

	Reduction in CO_2 Emissions Relative to BAU (Million Short Tons)	% Below 2005 Emission Levels	Compliance Cost (Million 2016$)	Average Abatement Cost[75] (2016$/ton)
PC1	382	50%	11,135	29
PC2	398	51%	9,342	23
PC3	462	53%	13,151	28
PC4	322	48%	6,731	21
PC5	305	48%	5,507	18

As shown in Table 3, emission reductions under PC2 are similar to PC1 despite the fact that PC2 does not include an emission limit on new sources. In fact, PC2 shows slightly greater emission reductions, which results from higher utilization of more efficient new generation. PC4 shows that averaging or trading across subcategories allows for more cost-effective abatement and PC5

[72] *See* ICF, *Assessing Effects on the Power Sector of Greenhouse Gas Emission Standards* (2018) (attached).
[73] *See id.* (The BAU is based on EPA IPM v5.16/EPA IPM v6 assumptions but was updated to reflect the latest load growth and renewable energy technology cost projections. For natural gas prices, we rely on EIA's AEO 2018 Reference Case projections. The BAU was also updated to include 45Q tax credit legislation and relies on EPA IPM v6 carbon capture and storage framework.)
[74] *See id.*
[75] Average overall abatement cost is calculated by dividing compliance cost with emission abatement.

shows that with greater compliance flexibility, including trading and demand-side energy efficiency, even more cost-effective abatement can be achieved. Indeed, ICF results show that under PC5, national carbon allowance prices would clear at just below $10/ton (2016$) in 2030.[76] According to ICF, since "higher levels of trading allows abatement to occur at units where it is most economic, [this] in turn allows units that have a higher cost of abatement to emit more. Lower levels of trading on the other hand force units to abate more evenly, which in turn may result in units that are cheaper to abate not realizing their full abatement potential . . . ."[77] Finally, PC3 demonstrates the feasibility of emissions-reducing utilization at the plant level even without allowing for any averaging or trading across facilities.

These results all demonstrate the feasibility and cost-reasonableness of an emissions-reducing utilization BSER. As shown in Table 3, significant emission abatement is achieved under all policy cases with emission levels of 48% or more below 2005 levels at costs below $30 per ton (2016$). Indeed in 2030, emission abatement under an emissions-reducing utilization BSER are more than 10 times higher than EPA's estimates of emission abatement under the Proposed Rule—more than 300 million short tons of abatement relative to BAU compared to less than 30 million short tons under the Proposed Rule in 2030.[78] These emission reductions are also achievable at abatement costs that are lower than those in the Proposed Rule.[79] EPA cannot simply rely on modest heat rate improvements at existing coal-fired EGUs that yield minimal, if any, emission reductions and neglect to consider other emission reduction systems such as emissions-reducing utilization that are feasible and can yield much greater and highly cost-effective emission reductions.

4. <u>EPA's proffered rationales for failing to consider emissions-reducing utilization as a potential BSER are unavailing.</u>

a. The CPP did not foreclose consideration of emissions-reducing utilization.

The ACE proposal claims that the CPP rules out "reduced utilization" as a BSER alternative by conflating reduced utilization at a single source with decreased output from all sources.[80] In fact, the CPP does not foreclose consideration of reduced utilization (or, by extension, emissions-reducing utilization) as the BSER for the typical source; it only rejects using "reduced overall

---

[76] *See id.*

[77] See i*d.*

[78] ACE RIA 3-15 tbl. 3-5 (comparing emissions under the Proposed Rule relative to No CPP base case).

[79] *Id.* tbl. ES-4 at ES-7, tbl. ES-6 at ES-8 (using compliance costs and emission abatement relative to No CPP base case for 2% HRI at $50/kW and 4.5% HRI at $100/kW illustrative scenarios yields $33 to $38/ton (2016$) in 2030. Note also that EPA's modeling in the ACE RIA relies on natural gas price projections that are on average 11% lower than EIA's AEO 2018 projections that we rely upon in our modeling, which means abatement costs in the Proposed Rule would be even higher under the same natural gas price projections. *See* Joint Environmental Comments on Regulatory Impact Analysis).

[80] ACE, 83 Fed. Reg. at 44,752 ("First, as explained in the CPP preamble, reduced utilization 'does not fit within our historical and current interpretation of BSER.'" However, the full quote is focused on overall generation, not a single source as EPA claims in the proposal. The full quote is as follows: "We are not finalizing our proposal that reduced overall generation of electricity may by itself be considered the BSER, for the reason that reduced generation by itself does not fit within our historical and current interpretation of the BSER. Specifically, reduced generation by itself is about changing the amount of product produced rather than producing the same product with a process that has fewer emissions." 80 Fed. Reg. at 64,780.).

generation of electricity" and "changing the amount of product produced rather than producing the same product with a process that has fewer emissions."[81] EPA's comments in this vein were made in the context of rejecting demand-side energy efficiency as a component of the best system of emission reduction, because it would reduce overall production of the product (electricity) in question. Emissions-reducing utilization does not reduce overall generation; it merely scales back generation at higher-emitting sources when lower-emitting sources can meet demand (which is assured by the centralized dispatch of resources interconnected nature of the power sector).[82] In essence, a BSER of emissions-reducing utilization does exactly what EPA requires from a BSER, producing "the same product with a process that has fewer emissions."[83] Indeed, in the CPP, EPA concludes that reduced utilization of higher-emitting units meets the all the statutory criteria to qualify as the BSER:

> Although, as discussed in the text in this section of the preamble, we are not treating reduced overall generation of electricity as the BSER (because it does not meet our historical and current approach of defining the BSER to include methods that allow the same amount of production but with a lower-emitting process) we note that reduced generation by individual higher-emitting EGUs to implement building blocks 2 and 3 meets the following criteria for the BSER: As the examples in the text and in the Legal Memorandum make clear, reduced generation is ''adequately demonstrated'' as a method of reducing emissions (because Congress and the EPA have recognized it and on numerous occasions, power plants have relied on it); it is of reasonable cost; it does not have adverse effects on energy requirements at the level of the individual affected source (because it does not require additional energy usage by the source) or the source category or the U.S.; and it does not create adverse environmental problems.[84]

Thus, the system is not only permissible under the EPA's interpretation of BSER in the CPP rulemaking but EPA found that it satisfies the statutory criteria. Because it would achieve far greater emission reductions than the system EPA proposes here, it would be a superior system and thus should be identified as the best system of emission reduction unless an alternative system achieves greater emission reductions.

b. Emissions-reducing utilization would not "inappropriately inject" EPA into operation decisions.

Although EPA acknowledges that "some emission reduction measures . . . may have an incidental impact on a source's production level," the Agency claims that "reduced utilization is directly correlated with a source's output" and "predicating a CAA section 111 standard on a

[81] CPP, 80 Fed. Reg. at 64,780.
[82] CPP, 80 Fed. Reg. at 64,780 ("The system is planned and operated to ensure that there are adequate resources to meet electricity demand plus additional available capacity over and above the capacity needed to meet normal peak demand levels. System operators have a number of resources potentially available to meet electricity demand, including electricity generated by electric generation units of various types as well as demand-side resources. Importantly, if generation is reduced from one generator, safeguards are in place to ensure that adequate supply is still available to meet demand.").
[83] *Id.*
[84] *Id.* at 64,782 n.602.

source's non-performance would inappropriately inject the Agency into an owner/operator's production decisions."[85] EPA provides no explanation, statutory justification, or support for this conclusory statement. As explained below, EPA already encourages or requires reduced utilization of electric generators in a variety of programs under the CAA, indicating that emissions-reducing utilization is generally not "inappropriate" under the statute. The fact that a regulation controlling emissions of dangerous substances into the atmosphere could influence a source's production decisions does not preclude the use of that approach. If it did, EPA would be unable to regulate any type of source because regulations will invariably affect production decisions. Moreover, particularly in the power sector, sources can hold no reasonable expectation that they will be allowed to produce as much electricity as they desire, because the electric system must balance supply and demand precisely, in real time, and current technology does not allow for large-scale storage.[86]

c. Other CAA programs and standards do not undermine—and in fact support—the inclusion of emissions-reducing utilization in EPA's BSER analysis.

EPA suggests in the proposed repeal of the CPP that several technology-based standard-setting provisions outside CAA section 111 limit, by analogy, the scope of BSER to "physical or operational changes to a source."[87] Elsewhere, EPA suggests that the BSER must involve "retrofit technology,"[88] recalling the measures Congress sought to impose in addressing haze. A close examination of each of these provisions reveals that emissions-reducing utilization is an available approach even assuming that the provisions somehow restrict the meaning of the term "best system of emission reduction" in section 111.

i. BART

The requirements of CAA section 169A can be met through reduced utilization even though "best available retrofit technology" ("BART") is an explicitly technological control. CAA section 169A directs EPA to require states to include in their air-pollution-control plans a requirement that major stationary sources emitting air pollutants that could impair visibility in certain exceptionally pristine and nationally important areas (mainly national parks and wildernesses) install BART.[89] Further:

> [I]n determining best available retrofit technology the State (or the Administrator in determining emission limitations which reflect such technology) shall take into consideration the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in

[85] ACE, 83 Fed. Reg. at 44,752.
[86] *See* Br. of *Amici Curiae* Grid Experts at 7, D.C. Cir. No. 15-1363) (filed Apr. 1, 2016).
[87] Proposed Repeal, 82 Fed. Reg. at 48,039-40.
[88] *Id.* at 48,037.
[89] 42 U.S.C. § 7491(b)(2)(A).

> visibility which may reasonably be anticipated to result from the use of such technology.[90]

Congress did not exempt all older sources from BART requirements.[91] Moreover, EPA's interpretation and implementation of the BART requirement underscores that the near-term retirement of polluting sources is an appropriate means to improve air quality. In its 2005 BART guidelines, EPA recommends that states take into account annualized costs of installing controls, including accelerated amortization for sources with short remaining lives.[92] These guidelines, moreover, require that the source's remaining useful life be "assured by a federally or State-enforceable restriction preventing further operation" if the remaining useful life is short enough to affect the BART determination.[93] In permitting states to impose less stringent requirements on sources about to cease operations, but requiring that such sources actually cease operations by a date certain in such circumstances, EPA effectively allowed states to weigh imminent non-utilization in determining compliance obligations.[94] Alternatively, states may choose to impose more-stringent requirements that force sources to shut down, reducing utilization to zero.[95] Because BART requirements (which are explicitly technological[96]) may be met by some facilities' ceasing operations altogether, effectively reducing utilization to zero either immediately or in the near term, it is reasonable to conclude that partial or total reduced utilization also falls within the open-ended "best system of emission reduction" under section 111.[97] Indeed, the Agency's own projections in the Regulatory Impact Analysis for the ACE proposal show that, under all of its illustrative scenarios, some coal-fired power plants will shut down instead of installing heat-rate improvements at the scale and cost levels assumed.[98]

---

[90] *Id.* § 7491(g)(2).

[91] *See id.* § 7491(b)(2)(A) (providing that BART requirements apply to all major stationary sources in existence as of August 7, 1977 and in operation since August 7, 1962).

[92] *See* 70 Fed. Reg. 39,104, 39,169 (July 6, 2005).

[93] 40 C.F.R. Part 51, Appendix Y, section IV(D)(4)(k).

[94] One option might be simply holding emission allowances for the remainder of a unit's life—a shorter compliance time than would apply to newer sources. *See* CPP Legal Memorandum at 39 ("Essentially, trading amortizes the costs of compliance over compliance periods. Affected EGUs with relatively short remaining useful lives need only comply for a proportionately smaller number of periods as compared with affected EGUs with relatively long remaining useful lives. Thus, the cost of complying with these emission guidelines is distributed in a way that is consistent with how the BART Guidelines compute the cost of compliance for sources with relatively short remaining useful lives.").

[95] *Cf.* 70 Fed. Reg. at 39,130 ("We did not intend . . . that the most stringent [BART] alternative must *always* be selected if that level would cause a plant to shut down." (emphasis added)).

[96] The fact that courts have upheld interstate emissions trading programs such as the Transport Rule as "better than BART" alternatives does not suggest that emissions-reducing utilization may not also be considered in BART analyses—especially since the "better" aspect of the alternatives often lies in trading rather than steps taken at any particular source. *See Nat'l Parks Conservation Ass'n v. McCarthy*, 816 F.3d 989, 995 (8th Cir. 2016) (crediting EPA's conclusion that the Transport Rule would "achieve greater, overall reasonable progress toward improving visibility than source-specific BART").

[97] As with BART, under section 111(d), some sources may become uneconomical under state-imposed standards and draw their utilization down to zero. H.R. Rep. No. 95-294, at 11 ("[S]tandards adopted for existing sources under section 111(d) of the act are to be based on available means of emission control (not necessarily technological) and must, *unless the State decides to be more stringent*, take into account the remaining useful life of the existing sources." (emphasis added)).

[98] *See* ACE RIA at 3-27 tbl. 3-20.

ii. BACT

In the proposed repeal of the CPP, EPA argued that "[a]dopting a source-oriented reading of 'through the application of the best system of emission reduction' . . . keeps CAA section 111 in line with other CAA standard-setting provisions."[99] Specifically, the Agency asserts that the use of the term "application" in the definition of the term "best available control technology" ("BACT") in the Prevention of Significant Deterioration ("PSD") program "signals a physical or operational change to a source."[100] As we explain elsewhere in our comments, the language, purpose, and operation of the PSD program are completely distinct from section 111—making EPA's proposed transfer of interpretations and policies from the PSD program to section 111 inappropriate and arbitrary. Even so, it is clear that emissions-reducing utilization may be part of BACT for any given source—and thus qualifies as a physical or operational change even within EPA's novel, narrow interpretation of "BSER."

CAA section 165 generally requires that new facilities emitting air pollution above certain thresholds, or major sources undergoing modifications that significantly increase emissions, deploy BACT for each pollutant regulated under the CAA.[101] Section 169, in turn, defines BACT as:

> an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.[102]

On its face, this definition encompasses approaches well beyond traditional technological controls, including different production processes and the use of alternative or pretreated fuels. Thus, the "application of" BACT to a source might involve changes to its operations that go beyond installing pollution controls or making efficiency improvements. As the Legal Memorandum supporting the CPP observes, "Permitting authorities have used limits on utilization as part of establishing BACT limits for EGUs."[103]

Accordingly, applying a system of emissions-reducing utilization—*i.e.*, limiting the annual hours over which a source may run—does not fundamentally alter its form or function in a way that exceeds the appropriate scope of BACT. Indeed, even where one of the purposes of the facility is to produce power, an agency may restrict the source of fuel as part of BACT.[104] Assuming that

[99] Proposed Repeal, 82 Fed. Reg. at 48,039.
[100] *Id.* at 48,039-40.
[101] 42 U.S.C. § 7475.
[102] *Id.* § 7479(3).
[103] CPP Legal Memorandum at 69 (citing examples); *see also id.* at 72-81 (listing examples of PSD permits that include limits on operation of EGUs).
[104] *See Helping Hand Tools v. EPA*, 836 F.3d 999, 1012 (9th Cir. 2016) (observing that the Agency had properly limited a lumber mill to burning trees removed during forest management).

the definition of BACT in section 169 somehow shapes the meaning of BSER in section 111, emissions-reducing utilization would comport with the Agency's historical understanding of BACT.

Even if BACT were confined to more-traditional technological controls, however, the different purposes of the PSD program and CAA section 111(d) counsel against a similarly limited interpretation of BSER. When Congress enacted the PSD program in 1977, it sought to encourage economic growth and drive technological innovation by requiring new sources and existing sources undergoing modifications to minimize their contribution to air pollution.[105] Each new and modifying plant would receive an individualized review to explore the ways in which its owner or operator might preserve air quality.[106] This program seeks to ensure that sources undertaking major investments, and which will be consuming part of the increment of clean air remaining in areas attaining national standards, install the best available control technology to mitigate the pollution increase.[107] The "application of" advanced technology to these new and modifying sources, at the design stage, is often easier than applying new technologies to existing sources.[108] In contrast, limits for existing sources under CAA section 111 are intended to reduce pollution from older facilities to protect public health and welfare.[109] CAA section 111's goal of improving health and welfare—by addressing all existing major sources of dangerous emissions not covered elsewhere under the Act, and outside the source-tailored inquiry under the PSD program—and the need for a broadly suitable, cost-reasonable system of emission reduction can readily be served by scaling back the rate at which older units run where the grid can supply sufficient lower emitting replacement generation.

iii. MACT

As with BACT, EPA contends that the use of the term "application" in the definition of the term "maximum achievable control technology" ("MACT") for hazardous air pollutants "signals a physical or operational change to a source."[110] The statutory language, legislative history, and Agency practice indicate that, even if this conclusion is correct, measures that are analogous to emissions-reducing utilization may also qualify as MACT and therefore are a "physical or operational change to a source" under EPA's narrow interpretation.

CAA section 112 requires EPA to establish emission standards that "require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section (including a prohibition on such emissions, where achievable) that the Administrator, taking into

---

[105] *See* S. Rep. No. 95-127, at 18 (1977) ("By imposing a ceiling on incremental pollution growth, setting an overall limit on emissions at any site[,] many industries can be expected to develop new, more effective techniques of control to meet that absolute constraint, while building a plant of maximum capacity. The more effective the controls, the larger the allowable plant.").
[106] *See id.*
[107] *See* H.R. Rep. No. 95-294, at 152 (1977) ("The committee emphasizes that the 'baseline pollution level' [for purposes of deriving a PSD increment] includes existing sources' emissions calculated on the basis of total plant capacity.").
[108] *Cf.* H*Id.* at 136 (noting that the PSD program would obviate "expensive retrofitting of pollution control technology" to stay below ambient standards).
[109] *See* 42 U.S.C. § 7411(b)(1), (d).
[110] Proposed Repeal, 82 Fed. Reg. at 48,039-40.

consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable for new or existing sources in the category or subcategory to which such emission standard applies."[111]

These emission standards must reflect MACT, which entails:

> application of measures, processes, methods, systems or techniques including, but not limited to, measures which--
>
> (A) reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications,
>
> (B) enclose systems or processes to eliminate emissions,
>
> (C) collect, capture or treat such pollutants when released from a process, stack, storage or fugitive emissions point,
>
> (D) are design, equipment, work practice, or operational standards (including requirements for operator training or certification) as provided in subsection (h), or
>
> (E) are a combination of the above.[112]

For existing sources, emission standards typically cannot be less stringent than the emission limitation achieved by the best-performing 12% of existing sources—the so-called "MACT floor."

Section 112 expressly authorizes EPA to consider measures beyond those listed in the statutory definition of MACT above,[113] but even limiting the measures to those above, constraining utilization of a source reduces the volume of pollution the source emits through a "process change."[114] Moreover, existing sources that cannot cost-effectively meet the emission limitation normally must shut down—reducing utilization to zero—because there is no accommodation for remaining useful life as in other CAA programs,[115] and EPA has only limited authority to grant variances from the requirements.[116]

In practice, EPA has set emission limitations for hazardous air pollutants that require regulated entities to consider pollution-reduction measures that are analogous to reduced utilization. For example, after establishing a numeric MACT floor based on the best-performing units, EPA required owners or operators of boilers to conduct a facility-wide "energy assessment" to identify conservation opportunities that would allow the sources to combust less fuel and thereby

---

[111] 42 U.S.C. § 7412(d)(2).
[112] *Id.*
[113] *See* H.R. Rep. No. 101-490, Part 1A (1990) (Conf. Rep.) (reiterating that "reduction strategies," a term that suggests decisions about how to allocate resources, under section 112 are not limited to those listed).
[114] 42 U.S.C. § 7412(d)(3).
[115] *See, e.g.*, U.S. Dep't of Energy Order No. 202-17-1 at 1-2 (Apr. 14, 2017) (issuing a temporary emergency exemption from EPA's Mercury and Air Toxics Standards to a coal-fired power plant planned for retirement).
[116] *See Nat. Res. Def. Council v. EPA*, 489 F.3d 1364, 1375-76 (D.C. Cir. 2007).

emit less pollution.[117] The court upheld the requirement based on EPA's authority under section 112 to regulate the entire source or facility (*i.e.*, as a within-the-fenceline measure).[118] Thus, under MACT, which has traditionally applied only "to or at" sources, the analysis encompasses operational measures that a source may take apart from any change to a physical process and that are designed to reduce the amount of fuel consumed by a facility.

For small, remote incinerators ("SRIs"), which are regulated under CAA section 129 but still must meet limitations based on MACT,[119] EPA considered segregating waste before combustion as a method SRIs could use to meet the MACT standard.[120] The court concluded that such an approach comports with the Agency's duty to consider "methods and technologies for removal . . . of pollutants before . . . combustion."[121] Yet segregating waste—including by diverting some of it to recycling programs[122]—is fundamentally different from removing pollutants before combustion, because the business purpose of incinerators is to burn refuse. Therefore, by segregating part of the waste and not burning it sources are lowering their intended utilization in order to reduce emissions. Emissions-reducing-utilization is even more reasonable for the power sector, where units are part of an interconnected grid, than for isolated incinerators, because there is little risk that "happenstance"[123] would prevent a power plant from decreasing generation: other resources stand ready to provide generation when needed, unlike with some SRIs that cannot send waste to distant municipal landfills or happen to have dirtier waste to burn than others.[124]

Finally, the fact that EPA allowed compliance extensions for power plants subject to the Mercury and Air Toxics Standards ("MATS")—extensions that were "necessary for the installation of controls,"[125] including generation-shifting—supports the conclusion that MACT is not limited to end-of-pipe technologies. As the Agency explained in the CPP legal memorandum:

> [I]n the final MATS rule the EPA formally interpreted "necessary for the installation of controls" as applying to a wide variety of on- and off-site actions that the owners and operators of EGUs can make to reduce emissions, which are made possible only because of the unique, interconnected nature of the electricity sector. Specifically, the EPA interpreted "installation of controls" to include not only construction of on-site replacement power, but also retirements, construction of off-site generation, or transmission upgrades. . . .
>
> The EPA believed that this interpretation was fully consistent with the requirement the fact that the extension "on its face applies to individual sources ...." This

[117] *U.S. Sugar Corp. v. EPA*, 830 F.3d 579, 613 (D.C. Cir. 2016).
[118] *See id.* at 615.
[119] *See id.* at 597.
[120] *Id.* at 619-20.
[121] *See id.* at 620 (quoting 42 U.S.C. § 7429(a)(3)).
[122] *See id.*
[123] *Id.* at 620-21 ("[T]he EPA acted reasonably when it decided to consider the emissions reduction that could be achieved by waste segregation in SRI units before combustion. This is true even if an element of 'happenstance' plays into an SRI unit's ability to segregate its waste.").
[124] *See id.* at 620.
[125] 42 U.S.C. § 7412(h)(4)(i)(3)(B).

> interpretation nevertheless complies with that source-specific requirement because off-site transmission upgrades, on- and off-site replacement generation, and retirement of the affect[ed] coal-fired EGU itself are all techniques that allow the EGU to reduce its emissions—in MATS, mercury and other hazardous emissions; in this rule, CO_2 emissions.[126]

This administrative precedent—and the vocal industry support it received during the MATS rulemaking[127]—indicates that compliance with requirements under CAA section 112, including MACT, may involve measures that include reductions in utilization or even retirements of sources.

iv. Acid Rain Program

The program that Congress enacted in 1990 in CAA Title IV to reduce emissions of sulfur dioxide and nitrogen oxides from power plants supports an interpretation that emissions-reducing utilization may qualify as the BSER. In the first phase of this Acid Rain Program, affected units could transfer compliance obligations to other units—*i.e.*, they could comply through trading.[128] Through a separate provision, they could earn additional credits for avoided emissions using renewable energy and energy efficiency, which essentially recognizes that sources could meet their emission limits by investing in renewable energy or energy efficiency and thereby lowering their output.[129] Congress also anticipated that some sources would choose to comply by reducing utilization and included specific requirements for tracking replacement generation.[130]

In the proposed repeal of the CPP, EPA argued against using the Acid Rain Program as an example that would justify a generation-shifting approach under section 111(d), contending that it is "unlikely that Congress would have silently authorized the Agency to point to <u>trading</u> in order to justify <u>generation-shifting</u> as a 'system of emission reduction.'"[131] EPA's assertion overlooks the fact that Congress was *not* silent. As explained above, it not only authorized trading in Title IV, but also affirmatively encouraged compliance through reduced utilization.

As EPA noted in the CPP, the definition of "standard of performance" in section 111(a)(1) does not identify particular compliance mechanisms because it applies to many different pollutants and source categories.[132] Section 111 is purposefully broad in order to address varied pollutants from different sectors of the economy. It uses language—the "best system of emission reduction"—that is intentionally flexible, and that contrasts with other Clean Air Act statutory frameworks that provide considerable guidance as to what is to be considered in setting a standard. Moreover, the fact that Congress indicated that reduced generation could be a

---

126 CPP Legal Memorandum at 115-16.
127 *See id.* at 114-15.
128 *See* 42 U.S.C. § 7651c(b).
129 *See id.* § 7651c(f)(2)(A), (B)(i); *see also* CPP, 80 Fed. Reg. at 64,731 ("Congress itself recognized in enacting the acid rain provisions of CAA Title IV that [renewable energy] measures reduce CO_2 from affected [electric generating units].").
130 *See* 42 U.S.C. § 7651g(c)(1)(B); *see also* CPP, 80 Fed. Reg. at 64,780.
131 Proposed Repeal, 82 Fed. Reg. at 48,042 (emphases added).
132 *See* CPP, 80 Fed. Reg. at 64,768.

compliance mechanism in Title IV—which dealt with electric generating units—suggests that emissions-reducing utilization is an appropriate approach to regulating these sources.

v. PSD "synthetic minors"

Emissions-reducing utilization is already used as a method for sources to avoid major source requirements in a variety of EPA programs including the program to control hazardous air pollutants under CAA section 112, the operating permits program under Title V of the CAA, the PSD permitting program under part C of Title I, and the Nonattainment New Source Review ("NNSR") permitting program under part D of Title I.[133] This type of potential to emit ("PTE") limit renders a source a "synthetic minor," which EPA guidance defines as "air pollution sources whose maximum capacity to emit air pollution under their physical and operational design is large enough to exceed the major source threshold but [is] limited by an enforceable emissions restriction that prevents this physical potential from being realized."[134] Each of these programs recognizes that a source may take enforceable restrictions on utilization, specifically including limitations on hours of operation, and thereby lower their PTE in order to fall below statutory thresholds that would otherwise classify them as major sources.[135] The implementing regulations for these programs specifically provide for emissions-reducing utilization in the form of PTE limits and treat them as equivalent to other enforceable restrictions on emissions, such as requirements for pollution control equipment.

The use of such PTE limits has been recognized by EPA in guidance documents,[136] rulemaking notices,[137] and orders signed by EPA Administrators responding to petitions for objection to Title

[133] *See id.* at 64,781 & nn. 596, 598.
[134] *In re Shell Offshore, Inc.*, 15 E.A.D. 536, 550, 2012 EPA App. LEXIS 11, *36 (E.P.A. Mar. 30, 2012).
[135] See regulations for PSD permitting program, 40 C.F.R. § 52.21(b)(4); SIP-approved PSD program, *id.* § 51.166(b)(4); SIP-approved NNSR programs, *id.* § 51.165(a)(1)(iii); Title V operating permit programs, *id.* § 70.2; and hazardous air pollutants, *id.* § 63.2.
[136] *See, e.g.*, Memorandum from Terrell Hunt, Assoc. Enforcement Counsel, U.S. EPA, & John Seitz, Director, Stationary Source Compliance Div., U.S. EPA, *Guidance on Limiting Potential to Emit in New Source Permitting*, at 1-2, 6 (June 13, 1989), ("1989 PTE Guidance"), *available at* https://www3.epa.gov/airtoxics/pte/june13_89.pdf; Memorandum from John Seitz, Dir., Office of Air Quality Planning & Standards, U.S. EPA, & Robert Van Heuvelen, Dir., Office of Regulatory Compliance, to EPA Reg'l Air Div. Dirs., *Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act (Act)* ("*Options for Limiting PTE*") (Jan. 25, 1995), *available at* https://www.epa.gov/sites/production/files/documents/limit-pte-rpt.pdf; EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, at 8 (Mar. 2011), EPA-457/B-11-001, *available at* http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.
[137] *See, e.g.*, 45 Fed. Reg. 52,689 (Aug. 7, 1980) (NSR rulemaking noting that availability of PTE limits in permit conditions addressed concerns raised concerning peak load units, among others); 67 Fed. Reg. 80,188 (Dec. 31, 2002) (NSR rulemaking); 61 Fed. Reg. 34,211-12 (July 1, 1996) (Title V Part 71 rulemaking).

V permits,[138] by EPA's Environmental Appeals Board in considering permit challenges,[139] and by federal courts.[140] By acknowledging that PTE limitations include both "air pollution control equipment" and "restrictions on hours of operation," EPA has already treated emissions-reducing utilization and emission reductions through air pollution control equipment as equally cognizable means of restricting potential emissions and complying with CAA obligations.

d. Measures that EPA views as within the new interpretation allow for emissions-reducing utilization.

End-of-pipe control technologies could result in changes in the dispatch of electric generating units by balancing authorities. These technologies may be "energy resource intensive" and therefore expensive to operate.[141] For this reason, EPA concludes in the CPP that certain technologies did not represent BSER, and that owners and operators of power plants would comply with a standard reflecting emission reductions achievable through them by shifting generation (i.e., reducing generation at emitting plants) or reducing demand and therefore reducing generation.[142] Viewed differently, a section 111(d) standard under which sources attempted to implement a BSER comprising retrofit technologies would lead balancing authorities to re-dispatch generation to lower-emitting, less-expensive resources.[143] This phenomenon shows that reduced utilization will happen—whether as a least-cost compliance mechanism or as the inevitable economic result—if it is in fact the best technique for reducing emissions.[144] Indeed, EPA's rationale in the Proposed Rule for rejecting co-firing with natural gas as the BSER, discussed below, suggests that, were the Agency to select this system and

---

[138] *See, e.g.*, *In re Orange Recycling and Ethanol Production Facility*, *Pencor Masada Oxynol, LLC*, Petition No. II-2001-05, at 4-10 (April 8, 2002), https://www.epa.gov/sites/production/files/2015-08/documents/masada-2_decision2001.pdf (denying petition's request to object to title V permit based on alleged flaws with PTE limits); *In re Columbia University*, Petition No.: II-2000-08, at 33-35 (Dec. 16, 2002), https://www.epa.gov/sites/production/files/2015-08/documents/columbia_university_decision2000.pdf (recognizing availability of PTE limits, but granting petition's request to object to Title V permit where PTE limits were not adequately enforceable); *In re Hu Honua Bioenergy LLC*, Petition No.: IX-2011-1, at 9-14, 16-19 (Feb. 7, 2014), https://www.epa.gov/sites/production/files/2015-08/documents/hu_honua_decision2011.pdf (recognizing availability of PTE limits and granting petition's request to object to Title V permit for proposed bioenergy electricity generating facility where PTE limits for criteria pollutants and HAPs were not adequately enforceable); *In the Matter Of Cash Creek Generation, LLC*, Petition No. IV-2010-4 at 14-15 (June 22, 2012), https://www.epa.gov/sites/production/files/2015-08/documents/cashcreek_response2010.pdf (granting in part and denying in part requests for objections based on alleged flaws in PTE limits for a new coal gasification facility and co-located natural gas combined cycle plant). In granting objections in some of these Title V orders, the EPA did not in any way diminish the viability of a PTE limit as a means of restricting utilization to ensure compliance. Rather, these objections were based on specific flaws that arose in these particular permitting actions.

[139] *See, e.g.*, *In re Shell Offshore, Inc.*, 15 E.A.D. 536, 550 n.15 (EAB 2012) (citing *In re Shell Offshore, Inc.*, *Kulluk Drilling Unit and Frontier Discoverer Drilling Unit*, 13 E.A.D. 357, 366 (EAB 2007); *In re Peabody Western Coal Co.*, 12 E.A.D. 22, 26 & n.11, 31. (EAB 2005)).

[140] *See, e.g.*, *United States v. Louisiana-Pacific Corp.*, 682 F. Supp. 1122, 1132-33 (D. Colo. 1987); *see also Weiler v. Chatham*, 392 F.3d 532, 535 (2d Cir. 2004) ("In short, then, a proposed facility that is physically capable of emitting major levels of the relevant pollutants is to be considered a major emitting facility under the Act unless there are legally and practicably enforceable mechanisms in place to make certain that the emissions remain below the relevant levels.").

[141] *See* CPP, 80 Fed. Reg. at 64,689, 64,727.

[142] *See id.* at 64,727-28 & n.373.

[143] *See, e.g.*, *id.* at 64,795 (describing "security-constrained economic dispatch").

[144] *See* Br. of *Amici Curiae* Grid Experts at 34-35, D.C. Cir. No. 15-1363) (filed Apr. 1, 2016).

allow for mass-based compliance, some generation could shift from coal-fired units to NGCCs.[145] Thus, while EPA could identify traditional technological controls as the BSER, such a determination would in fact lead to emissions-reducing utilization—a scenario that supports emissions-reducing utilization as an adequately demonstrated BSER.

B. Co-Firing with Natural Gas

Co-firing with natural gas at existing coal-fired steam EGUs, or wholesale conversion of those units to natural gas, is an adequately demonstrated and cost-effective way of significantly reducing carbon pollution and can yield significant reductions in co-pollutants. Even though EPA extensively considered this option in developing the CPP, and EDF and others filed extensive comments on this option in response to the December 2017 ANPR, the Proposed Rule rejects co-firing as infeasible and undesirable without performing *any* detailed analysis of costs, technical feasibility, emissions implications, or non-air quality health and environmental impacts.[146] Given the significant potential of natural gas co-firing and conversion to reduce emissions, and the information below on the feasibility and cost-effectiveness of this option, EPA's rejection of natural gas co-firing as the "best system" is manifestly arbitrary.

Technical Feasibility: As explained in detail in comments we filed in the ANPR record, the technology to co-fire natural gas or convert a coal-fired utility boiler to burn natural gas has been well-established for decades, and is commercially available and in widespread use.[147] In fact, natural gas co-firing is currently used in existing steam EGUs for a variety of reasons, including for emissions control, to make up for the low energy content of Western coals, and to assist with startup as gas igniters heat up the furnace to allow ignition of the coal. According to Andover Technology Partners, facilities that start up on gas have the ability to burn at least 10% of the heat input on gas through the gas igniters at no additional capital cost, and in some cases the boiler is designed to accept higher levels of gas without additional modifications.[148]

Power companies have been converting coal-fired units to burn natural gas as a primary fuel for over a decade.[149] Although conversion of a boiler to operate primarily on natural gas involves some physical modifications to the facility, these are often relatively modest. Coal-to-gas conversion projects can usually be accomplished without replacing the existing boiler, and often entail only construction of the natural gas delivery infrastructure—if not already available—and modifications to burners and ducts.[150] According to Andover, many such projects can be

[145] *See* ACE, 83 Fed. Reg. at 44,762 ("[I]t would not be an environmentally positive outcome for utilities and owner/operators to redirect natural gas from the more efficient NGCC EGUs to the less efficient coal-fired EGUs in order to satisfy an emission standard at the coal-fired unit.").
[146] *See, e.g.*, EDF ANPR Comments at 48; "Comments of the Natural Resources Defense Council on EPA's Advance Notice of Proposed Rulemaking: State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units," at 8-10, Docket ID No. EPA-HQ-OAR-2017-0545-0358 (Feb. 26, 2018).
[147] *See id.*
[148] Andover Technology Partners, Natural Gas Conversion and Cofiring for Coal-Fired Utility Boilers (2014).
[149] *See, e.g.*, Black & Veatch, A Case Study on Coal to Natural Gas Fuel Switch (2012) (describing the well-understood process for converting a coal-fired unit to run entirely on natural gas).
[150] Babcock & Wilcox, Natural Gas Conversions of Existing Coal-Fired Boilers (2010).

completed during periods when a plant is offline for maintenance and, excluding any pipeline construction, most projects take only a few months to complete.[151]

Andover's 2014 report on natural gas conversion and co-firing at coal-fired utility boilers (which was included in the record for the CPP) found at least 24 announced coal-to-gas conversions or co-firing projects in 19 states that were expected to be completed by 2020.[152] More recent studies have suggested that there could be more than 50 such conversions in 26 states at various stages of planning and development.[153] In its January 2017 Reconsideration Denial, EPA reported over 12 GW of capacity across 19 states that have switched their primary fuel from coal to natural gas.[154] Examples of plants that have converted from coal to natural gas include four coal-fired units at Southern Company's Ernest C. Gaston station near Wilsonville, Alabama, and two coal-fired units at Appalachian Power's Clinch River Power Plan in Virginia.[155] Recent analysis by Northbridge for Clean Air Task Force also shows that over 10 GW of coal capacity that exists in a variety of states, ownership structures, and regulatory regimes has converted to natural gas or invested in co-firing capabilities.[156] The Proposed Rule fails to acknowledge these developments or undertake any assessment of the extent to which steam EGUs already have access to natural gas.

The Proposed Rule also incorrectly asserts, without providing *any* record support, that pipeline infrastructure limitations would preclude the use of increased natural gas co-firing to reduce emissions. This conclusion ignores information that EPA itself developed as part of the record for the CPP. During the development of the CPP in 2013, EPA evaluated the distance of natural gas pipelines to coal plants to assess the potential for coal-to-gas conversions. EPA found that 25% of the existing coal fleet was within 25 miles of a natural gas pipeline.[157] Since then, there has been significant development of natural gas infrastructure. In 2015, the U.S. Department of Energy ("DOE") looked at natural gas use in the U.S. under a carbon policy for power plants and found that new interstate pipelines would likely not be necessary even under a high natural gas demand case, due in part to natural gas pipelines being underutilized.[158]

In addition, EDF has attached to these comments a new analysis from M.J. Bradley & Associates ("MJB&A") that evaluates the availability of natural gas transportation capacity in interstate pipelines and finds significant potential for increased natural gas co-firing at existing coal-fired

[151] Andover Technology Partners, Natural Gas Conversion and Cofiring for Coal-Fired Utility Boilers.
[152] *Id.*
[153] *See* Sourcewatch, *Coal Plant Conversion Projects* (last visited Oct. 23, 2018), https://www.sourcewatch.org/index.php/Coal_plant_conversion_projects.
[154] CPP Reconsideration Denial: Appendix 3, at 19.
[155] *Id.* at 3; *see also* Scott Gossard, *Coal-to-Gas Plant Conversions in the U.S.*, Power Engineering (June 18, 2015), http://www.power-eng.com/articles/print/volume-119/issue-6/features/coal-to-gas-plant-conversions-in-the-u-s.html.
[156] Comments of the Clean Air Task Force on EPA's 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 (Oct. 31, 2018).
[157] *See* EPA Documentation for Base Case v.5.13: Emission Control Technologies, Chapter 5 and Table 5-22, https://www.epa.gov/airmarkets/documentation-base-case-v513-emission-control-technologies.
[158] U.S. Dep't of Energy, Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector (Feb. 2015), https://energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20Natural%20Gas%20Infrastructure%20Implications%20of%20Increased%20Demand%20from%20the%20Electric%20Sector.pdf.

EGUs.[159] MJB&A mapped all existing coal-fired EGUs that were in operation in 2018 in the lower 48 U.S. states to the existing interstate natural gas pipeline infrastructure.[160] By examining daily flow volumes at each natural gas flow point or meter point attached to interstate pipelines over a multi-year period from 2012 through 2017, MJB&A was able to estimate operationally available capacities for additional gas flow through each flow point.[161] MJB&A examined several co-firing scenarios including the use of the average available gas capacity at each flow point and a more conservative base scenario that relied on the mid-point of the average and minimum available gas capacity.[162] Coal-fired EGUs' natural gas needs for co-firing were calculated based on their 2015 generating output and adjusted heat rates to account for any efficiency loss from the co-firing process.[163]

As shown in Figure 1 below, MJB&A found that the existing interstate natural gas pipeline infrastructure and natural gas flow volumes in the recent past suggest that roughly 60% of the existing U.S. coal-fired fleet would be able to convert entirely to natural gas, and about 75% would be able to achieve some level of co-firing.[164] MJB&A also found that nearly 60% of the existing coal-fired fleet would need less than 25 miles of lateral pipelines to transport natural gas from their nearest interstate pipeline flow points and, at more than 50% of the existing coal-fired EGUs, only one lateral pipeline to the nearest interstate pipeline is needed.[165] According to MJB&A, in most states the majority of existing coal-fired EGUs are already equipped to co-fire with natural gas at some level.[166]

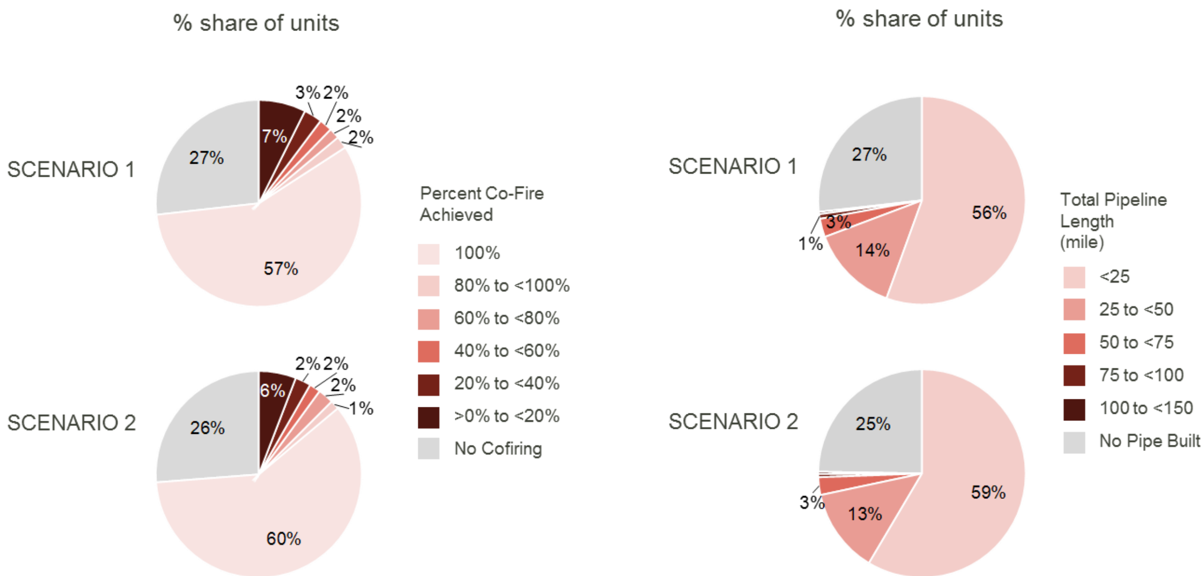
As noted by MJB&A, its analysis considers only interstate pipelines that are already in service with flow points reporting gas flow data—in other words, pipelines with in-service dates in the future as well as those with missing or unreported flow point data are not factored into the analysis. Further, a large share of gas pipelines in Texas are intrastate and not considered in MJB&A's analysis due to lack of data availability for flow points on intrastate pipelines.[167] Including interstate natural gas pipelines with in-service future dates as well as the intrastate natural gas pipeline infrastructure in Texas would yield even greater co-firing potential.

In sum, many existing steam EGUs are already equipped to co-fire natural gas and would require either modest modifications or no modifications to increase their utilization of natural gas. Moreover, the *current* interstate pipeline infrastructure has sufficient capacity to allow a majority of steam EGUs to substantially increase their use of natural gas or even convert entirely to natural gas. In light of this record evidence, it is manifestly arbitrary for EPA to reject the possibility of *any* increase in natural gas co-firing on grounds of technical feasibility or infrastructure limitations.

---

[159] M.J. Bradley & Associates, Pipeline Analysis Results (October 2018) ("MJB&A Natural Gas Pipeline Analysis")
[160] *Id.* at 5.
[161] *Id.* at 5, 7.
[162] *Id.* at 6.
[163] *Id.*
[164] *Id.* at 11.
[165] *Id.* at 12.
[166] *Id.* at 14.
[167] *Id.* at 4.

Figure 1: Number of Coal-Fired Units by Achieved Level of Co-Firing and Length of Pipeline Laterals[168]



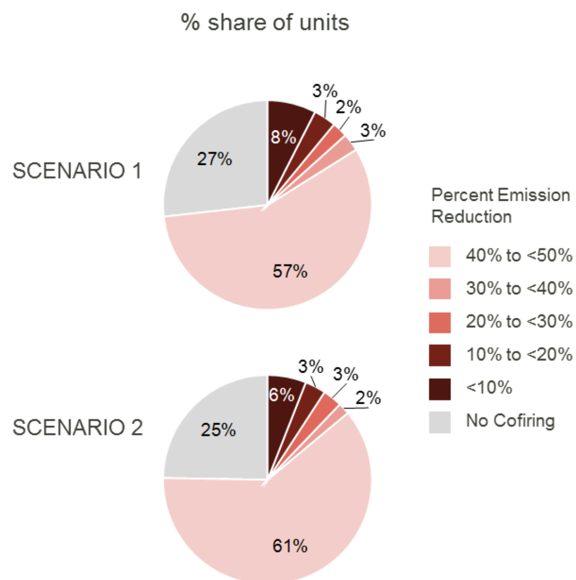
Environmental and Health Impacts: As already discussed in comments we filed in the ANPR record, co-firing with or switching to natural gas has significant potential for reducing CO_2 emissions from coal-fired EGUs.[169] EPA's analysis for the proposed CPP showed that 10% natural gas co-firing at a utility boiler could lead to an emission rate of 2,021 lbs CO_2/MWh_{net}, roughly 4% lower than 100% coal firing.[170] Fifty percent natural gas co-firing could lower the emission rate to 1,673 lbs CO_2/MWh_{net}, representing a 21% reduction.[171] Switching to 100% natural gas at fossil steam units could reduce the CO_2 emission rate by 42.8%.[172] Indeed, according to case studies by Andover, five units that have already completed conversions have reported an average 38% reduction in CO_2 emission rates.[173]

In its analysis of natural gas co-firing potential, MJB&A finds that a technical maximum of 614 million short tons or 43.5% reduction in CO_2 emissions from 2015 levels at existing coal-fired EGUs is possible.[174] MJB&A also finds that the existing natural gas pipeline infrastructure alone may be adequate to produce more than a 20% reduction in CO_2 emissions of the existing coal-fired EGU fleet—almost 50% of the technical maximum possible.[175] Indeed, according to

[168] *Id.* at 11-12 (showing that roughly 60% of the existing U.S. coal-fired fleet would be able to convert entirely to natural gas and nearly 60% would need less than 25 miles of lateral pipelines. Scenario 1 represents a conservative base scenario using the mid-point of the average and minimum available gas capacity, and Scenario 2 uses the average available gas capacity).
[169] EDF ANPR Comments at 51.
[170] EPA, GHG Abatement Measures Technical Support Document at 6-6 tbl. 6-1 (June 2014).
[171] EDF ANPR Comments at 51.
[172] CPP Reconsideration Denial: Appendix 3 at 16.
[173] Andover Technology Partners, Natural Gas Conversion and Cofiring for Coal-Fired Utility Boilers, at 3.
[174] MJB&A Natural Gas Pipeline Analysis
[175] *Id.*

MJB&A's analysis and as shown in Figure 2 below, roughly 60% of existing coal-fired EGUs would see CO_2 emission reductions of 40% to 50% relative to 2015 emissions.[176] This is consistent with MJB&A's finding that nearly 60% of the existing coal-fired fleet would be able to meet 100% of their co-firing related natural gas needs.[177] MJB&A also notes that new pipelines under various stages of planning and construction were not considered in its analysis and could produce even further opportunities for emission reduction.[178]

Figure 2: Number of Coal-Fired Units by Percent Carbon Dioxide Emission Reduction Relative to 2015 Levels[179]



In the proposed CPP, EPA also reasonably estimated that converting to 100% natural gas would significantly reduce a unit's emissions of sulfur dioxide ("SO_2"), nitrogen oxides ("NO_x"), and fine particulate matter ("$PM_{2.5}$").[180] The five completed conversion projects documented in the Andover report show average emission rate reductions of 99% for SO_2 and 48% for NO_x.[181] These pollutants' serious health impacts are well documented. According to EPA, the value of the health benefits associated with these reductions are estimated to be between $67/MWh$_{net}$ and $150/MWh$_{net}$—a factor of at least two times the cost associated with conversion.[182]

---

[176] *Id.* at 10.
[177] *Id.* at 11.
[178] *Id.*
[179] *Id.* at 10 (showing that roughly 60% of the existing U.S. coal-fired fleet would see CO_2 emission reductions of 40% to 50% relative to 2015 emissions. Scenario 1 represents a conservative base scenario using the mid-point of the average and minimum available gas capacity, and Scenario 2 uses the average available gas capacity).
[180] EPA, GHG Abatement Measures Technical Support Document, at 6-6 tbl. 6-2. EPA estimated that 100% natural gas conversion would reduce SO_2 emissions by 3.1 lb/MWh$_{net}$, NO_x by 2.04 lb/MWh$_{net}$, and $PM_{2.5}$ by 0.2 lb/MWh$_{net}$.
[181] Andover Technology Partners, Natural Gas Conversion and Cofiring for Coal-Fired Utility Boilers.
[182] EPA, GHG Abatement Measures Technical Support Document, at 6-7 tbl. 6-3. Even with a steep 7% discount rate, EPA estimated the health benefits of reducing co-pollutants through 100% natural gas conversion to be between $61/MWh$_{net}$ and $140/MWh$_{net}$. EPA estimated the value of the health benefits associated with 10% natural gas co-firing to be between $6.5/MWh$_{net}$ and $15/MWh$_{net}$.

Switching to natural gas firing at existing units also has substantial non-air health and environmental benefits. For instance, coal-to-gas conversion eliminates an existing unit's production of coal combustion residuals or coal ash, an industrial waste that contains toxic substances such as arsenic, selenium, and cadmium. Conversion to natural gas also reduces on-site water quality impacts.[183]

Cost: As discussed in comments we filed in the ANPR record, natural gas co-firing has long been recognized as a cost-effective option for coal-fired boilers to reduce emissions of criteria and hazardous pollutants.[184] In the final NSPS for new, modified, and reconstructed electric generating units, EPA also found natural gas co-firing to be cost-effective for achieving carbon emission limitations.[185] Indeed, the fact that many conversion projects have recently been completed or are currently underway demonstrates that costs are reasonable. According to Andover, many power companies are undertaking coal-to-gas conversions because they sometimes represent the most economical option for complying with emission limitations.[186]

In its analysis of natural gas co-firing potential at existing coal-fired EGUs, MJB&A estimates the levelized cost of avoided carbon pollution from co-firing to be in the range of $67 to $72 per ton across all scenarios through 2035.[187] According to MJB&A's analysis, EGU retrofit and pipeline costs contribute a relatively small part to the levelized abatement cost.[188] In other words, units can undergo co-firing at reasonable cost even when they are located at a significant distance from existing pipeline infrastructure. MJB&A's analysis also shows a decrease in a unit's fixed and variable operating costs with natural gas co-firing.[189] In fact, the majority of the abatement cost from natural gas co-firing is fuel cost.[190]

Importantly, MJB&A's cost analysis is conservative in several respects. First, it relies on natural gas price projections from the Energy Information Administration's ("EIA") 2018 Annual Energy Outlook ("AEO") Reference Case and accounts for potential increases in natural gas prices due to additional incremental natural gas demand from co-firing at existing coal-fired EGUs.[191] Using lower natural gas price projections consistent with EIA's AEO 2018 High Oil and Gas Resource and Technology case would yield much lower abatement costs for co-firing. Indeed, EPA's own Regulatory Impact Analysis for the ACE rulemaking relies on natural gas price projections that are on average 11% lower than EIA's AEO 2018 Reference Case.[192] Using EPA's own natural gas price projections would mean lower co-firing abatement costs, on the order of 11% lower than MJB&A estimated since overall abatement costs are dominated by fuel costs.

---

[183] EDF ANPR Comments at 52.
[184] *Id.* at 50.
[185] EPA, Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,510, 64,530 (Oct. 23, 2015) ("GHG NSPS Final Rule").
[186] Andover Technology Partners, Natural Gas Conversion and Cofiring for Coal-Fired Utility Boilers.
[187] MJB&A Natural Gas Pipeline Analysis.
[188] *Id.*
[189] *Id.*
[190] *Id.*
[191] *Id.*
[192] *See* Joint Environmental Comments on Regulatory Impact Analysis.

Moreover, MJB&A's scenarios assume near-maximum levels of natural gas co-firing using the existing interstate pipeline infrastructure, *without* considering how existing EGUs would alter their utilization if they were required to use such high levels of co-firing. Due to the interconnected nature of the grid and the sensitivity of power plant dispatch to changes in relative costs, it is virtually certain that steam EGUs would reduce their utilization in response to a requirement to use increased levels of natural gas co-firing. This would significantly lower the costs associated with natural gas co-firing in an absolute and relative sense. Likewise, the costs of natural gas co-firing would be lower if the analysis had assumed lower levels of co-firing. In fact, modeling in IPM performed by ICF, International Inc. for the Natural Resources Defense Council ("NRDC"), relying on assumptions specified by NRDC, shows that emission rate targets based on 60% co-firing at existing coal-fired EGUs would result in lower utilization of these units—61% utilization versus 70% utilization under business-as-usual in 2030—and yield significant carbon pollution reductions at a cost of $24 per ton (2016$).[193]

Conversion of a Steam EGU to Natural Gas is not Precluded by the Redefining the Source Policy. We explain in the Joint Environmental Comments on the BSER that it would be unlawful and arbitrary for EPA to apply the "redefining the source" policy from the PSD permitting context to preclude the consideration of certain systems of emission reduction under section 111. Even if the "redefining the source" policy did apply, however, it would not categorically preclude the conversion of steam EGUs to natural gas as EPA argues in the Proposed Rule.[194] As we explain above, many steam EGUs are either already equipped to utilize natural gas as a primary fuel source or can undertake relatively modest modifications to do so. Many steam EGUs are also either already connected to natural gas supply infrastructure or are located close to natural gas pipelines with adequate available capacity to supply all or a large portion of their heat input requirements. Further, a substantial number of formerly coal-fired steam EGUs have *already* fully converted to natural gas to comply with the Mercury and Air Toxics Standards or other regulatory requirements, or in response to market pressures. This record evidence contradicts EPA's completely unsupported assertion in the Proposed Rule that natural gas conversion would implicate the redefining the source policy because it would require "significant modification" or "decommissioning, redesign, and new construction."[195] It also shows that conversion to natural gas is a measure these sources can take "to reduce pollutant emissions without disrupting [their] basic business purpose."[196]

Neither does the Proposal's implication that a switch in "primary fuel type" would redefine the source mean that conversion of steam EGUs to natural gas is categorically precluded.[197] That converting a coal-fired steam EGU to natural gas would entail a change in primary fuel type does not mean that it would redefine the source. The definition of "best available control technology" specifically incorporates "clean fuels" as an option that PSD permitting authorities must

---

[193] Comments of the Natural Resources Defense Council on EPA's 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 (Oct. 31, 2018).
[194] ACE, 83 Fed. Reg. at 44,753.
[195] ACE, 83 Fed. Reg. at 44,753.
[196] *Helping Hand Tools v. EPA*, 848 F.3d 1185, 1194 (9th Cir. 2016).
[197] ACE, 83 Fed. Reg. at 44,752.

consider, and the conversion of a steam EGU to natural gas (especially where the EGU is already using natural gas in some form) easily fits within that statutory mandate.[198]

And contrary to EPA's suggestion in the Proposed Rule,[199] neither EPA's own permitting guidance nor administrative precedents indicates that a change in primary fuel type invariably redefines the source. As we explain in the Joint Environmental Comments on the BSER, the "redefining the source" policy requires a case-by-case "hard look" at the basic business purpose of individual facilities, and does not allow an "automatic off-ramp" for any particular control measure.[200] To be sure, there are cases (involving, for example, power plants located at the mouth of a coal mine) in which PSD permitting authorities applying the "redefining the source" policy have found that the consumption of coal as a primary fuel is part of the "basic business purpose" of a particular facility.[201] However, these cases have typically involved unique situations in which a particular facility was located adjacent to – and premised on the use of – a particular stockpile or source of fuel. Where such constraints have not applied, PSD permitting authorities have found that a facility's primary fuel type is *not* essential to its "basic business purpose" and that the facility *must* therefore consider switching to a cleaner fuel type as a control option.[202]

Moreover, EPA's own permitting guidance for greenhouse gases—which is cited in the Proposed Rule—similarly recognizes that a secondary fuel (such as natural gas) that is already "incorporated . . . into one aspect of the project design (such as startup or auxiliary applications)" is "available" to an applicant and should be considered as a potential control option.[203] In light of these precedents and the information in this docket underscoring the present availability of natural gas at many steam EGUs and the feasibility of converting those EGUs to natural gas, it is arbitrary for EPA to categorically rule out conversion to natural gas as a potential "best system" for *any* steam EGUs based on its hand-waving invocation of the "redefining the source" policy.

Arbitrariness of EPA's Analysis. The cursory analysis of co-firing that appears in the Proposed Rule considers none of these factors, and is therefore manifestly arbitrary. EPA dismisses the possibility of natural gas co-firing as the "best system"—at *any* level and for *any* EGU—because of unexplained concerns about the supposed costs of modifying EGUs to operate on natural gas, and pipeline capacity constraints and natural gas availability. Yet EPA provides no support to substantiate these concerns, much less any demonstration that such concerns are so serious and so widespread that no subcategory of steam EGU should be subject to a standard based on natural gas co-firing. There is simply no evidence in the rulemaking record that EPA has made

---

[198] 42 U.S.C. § 7479(3).
[199] ACE, 83 Fed. Reg. at 44,752.
[200] *In re Ariz. PSC Ocotillo Power*, 17 E.A.D. 323, 336-37 (E.P.A. Sept. 1, 2016) (citing *In re N. Mich. Univ.*, 14 E.A.D. 283, 302 (EAB 2009); *In re La Paloma,* 16 EAD 267, 289 (EAB 2014)).
[201] *In re Prairie State*, 13 E.A.D. at 28.
[202] *See In re Hibbing Taconite Co.*, 2 E.A.D. 838, 843(Adm'r 1989) (finding it reasonable to consider burning natural gas instead of or in combination with coal where the plant at issue was already equipped to burn natural gas); *In re Cash Creek Generation LLC,* 2009 EPA CAA Title V LEXIS 4, 25-26 (EAB 2009); *In re Desert Rock,* 14 E.A.D. at 538 (finding that converting proposed pulverized coal plant to integrated gasification combined cycle technology would not alter the "business purpose" of the facility and must be considered as potential BACT).
[203] *See* EPA, PSD and Title V Permitting Guidance for Greenhouse Gases at 28.

the requisite "reasonable effort to develop the facts," and EPA instead appears to have rejected co-firing based on an arbitrary and impermissible "guess about what the facts might be."[204]

Meanwhile, EPA's own prior analyses for the CPP as well as the information set forth above indicates that natural gas co-firing is available to a large majority of steam EGUs (and that many EGUs already use natural gas co-firing, or wholesale conversion, for emissions control); that the costs of lateral pipelines and EGU modifications needed to enable natural gas co-firing are modest; that *existing* interstate pipeline transmission capacity is ample enough to permit much higher levels of co-firing; and that the emissions benefits of a standard based on natural gas co-firing would be significant (and far greater than the trivial and potentially nonexistent emission reductions anticipated from this Proposed Rule).

In addition to the lack of support for EPA's contentions, EPA fails in the Proposed Rule to consider whether any of the concerns it has raised could be avoided or mitigated through appropriate subcategorization of steam EGUs. For example, EPA does not consider whether certain steam EGUs that are already equipped to use natural gas as a secondary fuel could increase their utilization without additional physical modifications. It does not consider whether certain steam EGUs that are located closer to interstate pipelines, or to pipelines that have demonstrable spare capacity, would find it more cost-effective and feasible to co-fire. In light of the patent inadequacies of HRI as a BSER, and the urgent need to achieve significant reductions in climate pollution from the power sector, EPA's failure to consider these obvious "reasonable alternatives" is arbitrary.[205]

EPA also asserts in the Proposed Rule that natural gas co-firing cannot be the BSER because "co-firing natural gas in coal-fired utility boilers is not the best, most efficient use of natural gas" and that co-firing could "redirect" natural gas from more efficient NGCCs. EPA does not explain how it has determined that co-firing is not the "best" use of natural gas. Indeed, the information we have provided above about the emissions benefits of co-firing, and the fact that many power companies have either converted their steam EGUs entirely to natural gas or undertake co-firing at some level, suggests that EPA's determination is incorrect.[206]

EPA's claim that co-firing natural gas at steam EGUs would somehow "redirect" natural gas from NGCC units is also completely unsupported. Moreover, it is directly contradicted by the MJB&A analysis above, which fully takes into account demand for natural gas from existing NGCC units. MJB&A's analysis further found that increased natural gas demand resulting from

---

[204] *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 531 (D.C. Cir. 1983).

[205] *Del. Dep't of Nat. Res. v. EPA*, 785 F.3d 1, 18 (D.C. Cir. 2015) ("Because EPA too cavalierly sidestepped its responsibility to address reasonable alternatives, its action was not rational and must, therefore, be set aside.") (citations omitted).

[206] *See* Comments of the Clean Air Task Force on EPA's 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 (Oct. 31, 2018) (showing over 10 GW of coal capacity that exists in a variety of states, ownership structures, and regulatory regimes that has converted to natural gas or invested in co-firing capabilities); *see also* Comments of the Natural Resources Defense Council on EPA's 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 (Oct. 31, 2018) (Appendix listing over 50 GW of U.S. coal units that currently co-fire with natural gas).

increased co-firing would be well within current EIA forecasts for future natural gas demand growth, and would have minimal impacts on natural gas prices. There is simply no basis for EPA to claim that natural gas supplies are so constrained that designating co-firing as the BSER (at any level and for any EGU) would divert natural gas from NGCC (or any other use).

C. **Carbon Capture and Storage**

As discussed in detail in comments we filed in the ANPR record, carbon capture and storage ("CCS") is adequately demonstrated and has been successfully implemented at multiple projects around the world over several decades.[207] EPA should consider CCS as a potential BSER for existing coal-fired electric generating units. Since submission of our comments on the ANPR in February 2018, Congress passed 45Q tax credit legislation, opening up even more cost-effective opportunities for carbon capture and storage projects.

Technical Feasibility: In promulgating New Source Performance Standards ("NSPS") for carbon pollution from new, modified, and reconstructed power plants, EPA discussed in great detail both the technology and feasibility of CCS to limit carbon pollution emissions from new fossil fuel-fired electric generating units.[208] EPA found that CCS has been adequately demonstrated in full-scale operations at steam electric generating units, and is the system that achieves the greatest degree of emission reduction from those units at acceptable cost. EPA determined that the BSER for new steam generating units is a highly efficient supercritical pulverized coal boiler using partial post-combustion CCS technology.[209]

For existing steam generating units, retrofit CCS is also broadly available across the U.S. A 2010 study by DOE's National Energy Technology Laboratory ("NETL") evaluated the feasibility of retrofitting capture technology at existing power plants, using aerial and satellite images of various power plant sites, and concluded that no sites were totally infeasible for retrofit.[210] A study by well-regarded power engineering experts at Carnegie Mellon University modeled the feasibility of reducing unit-level CO_2 emission rates by 30% through CCS retrofits at existing coal-fired EGUs and found that about 60 GW of the existing coal-fired capacity is amenable to CCS—roughly 20% of the coal-fired fleet.[211]

---

[207] There are currently 17 large-scale CCS facilities operating globally and an additional four coming on stream in 2018. *See* Global CCS Institute, *The Global Status of CCS: 2017*, http://www.globalccsinstitute.com/sites/www.globalccsinstitute.com/files/uploads/global-status/1-0_4529_CCS_Global_Status_Book_layout-WAW_spreads.pdf.
[208] *See* GHG NSPS Final Rule; Literature Survey of Carbon Capture Technology Technical Support Document (July 10, 2015).
[209] *Id.*
[210] *See* IEAGHG, Retrofitting CO_2 Capture to Existing Power Plants (May 2011) at 84, 86, http://ieaghg.org/docs/General_Docs/Reports/2011-02.pdf; *see also* Clean Air Task Force, Comments on EPA's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units, at 38-39 (Dec. 1, 2014).
[211] Haibo Zhai, Yang Ou, & Edward S. Rubin, *Opportunities for Decarbonizing Existing U.S. Coal-Fired Power Plants via CO_2 Capture, Utilization, and Storage*, Envtl. Sci. & Tech. (May 2015), http://www.cmu.edu/epp/iecm/rubin/PDF%20files/2015/Pages%20from%20Zhai_Rubin_CCUSretrofits_ES&T_2015.pdf; *see also* CPP Reconsideration Denial: Appendix 3, at 5.

Since finalizing the NSPS and the CPP, at least one additional retrofit project on an existing steam generating unit has been completed: the Petra Nova project, which is a commercial-scale post-combustion carbon capture project at Unit #8 of NRG Energy's W.A. Parish generating station. The project is designed to capture approximately 90% of the CO_2 from a 240 MW slip-stream of the 610 MW W.A. Parish facility—roughly 35% of the plant's total carbon pollution emissions. The project was originally envisioned as a 60 MW slip-stream demonstration and received DOE Clean Coal Power Initiative funding on that basis. However, the project was later expanded to the larger 240 MW slip-stream in order to capture greater volumes of CO_2 for enhanced oil recovery ("EOR"). No additional federal funding was obtained for the expansion. The Petra Nova project successfully started operation in December 2016 and will capture over 1 million tons of CO_2 each year.[212]

Another project that further demonstrates the feasibility of retrofitting CCS to an existing power plant is the Boundary Dam Unit 3 CCS project in Canada which is operated by SaskPower.[213] Recent data shows that since operation began in October 2014, the unit has captured over 2 million metric tons of CO_2.[214] CCS is also being utilized at other non-utility industrial sources. In April 2017, the world's first large-scale bioenergy with CCS facility was launched into operation in Illinois.[215]

Opportunities to store captured CO_2 are also widely available across the country. In the NSPS rulemaking, EPA discussed in great detail the geographic availability of geologic sequestration,[216] and since EPA finalized the NSPS and the CPP, DOE has published additional information that continues to show that geologic sequestration is available throughout most of the United States.[217] This data identified 39 states with potential onshore and offshore deep saline formation storage resources; EOR operations were being conducted in 12 states with an additional 17 states having geology that may be amenable to EOR operations.[218] The data also showed 20 states within 100 km of an active EOR location and 13 states that have operating CO_2 pipelines.[219] DOE estimates potential storage capacity of approximately 2,420 billion metric tons to more than 21,299 billion metric tons of CO_2 in the U.S. from deep saline formations, oil and gas reservoirs, and un-mineable coal seams.[220]

---

[212] *See* NRG, *Petra Nova – WA Parish Generating* Station, http://www.nrg.com/generation/projects/petra-nova/; Umair Irfan, *World's Largest Carbon Capture Retrofit On Track To Open*, (Oct. 4, 2016), http://www.eenews.net/climatewire/2016/10/04/stories/1060043791; Chris Mooney, *America's First 'Clean Coal' Plant Is Now Operational — and Another Is on the Way*, Wash. Post, (Jan. 10, 2017); https://www.washingtonpost.com/news/energy-environment/wp/2017/01/10/americas-first-clean-coal-plant-is-now-operational-and-another-is-on-the-way/?utm_term=.69047055d77e; *see also* CPP Reconsideration Denial: Appendix 3.

[213] CPP Reconsideration Denial: Appendix 3, at 4.

[214] SaskPower, *BD3 Status Update: April 2018* (May 8, 2018), https://www.saskpower.com/about-us/our-company/blog/bd3-status-update-april-2018.

[215] *See* Global CCS Institute, *The Global Status of CCS: 2017*, http://www.globalccsinstitute.com/sites/www.globalccsinstitute.com/files/uploads/global-status/1-0_4529_CCS_Global_Status_Book_layout-WAW_spreads.pdf.

[216] *See* GHG NSPS Final Rule; EPA, "Geographic Availability" Technical Support Document (July 31, 2015).

[217] *See* CPP Reconsideration Denial: Appendix 3, at 6.

[218] *Id.*

[219] *Id.*

[220] *See id.* at 7.

A recent study conducted for the Clean Air Task Force ("CATF") maps existing coal-fired power plants to saline storage and oil and gas fields and demonstrates the significant potential for carbon capture and storage at existing coal plants.[221] The study shows that 90% of existing coal plants are within 100 miles from the center of a basin with adequate capacity and more than half of the existing plants are less than 10 miles from the center of a basin.[222]

Cost: The cost of retrofitting a plant with CCS depends on several factors including proximity to EOR sites or pipelines, the costs of capturing CO_2, transporting it by pipeline, and the revenue that a power plant owner receives for selling the CO_2 to the oil field. In 2014, NETL estimated the cost of capture to be just over $70 per metric ton of CO_2 at an existing pulverized coal power plant.[223] Since then, CCS costs have continued to decline, and recent 45Q tax credit legislation has made CCS even more cost-effective. Recent analysis by the Clean Air Task Force estimates the total overnight capital cost of CCS retrofits at existing coal-fired power plants to be $1,190 per net kW of de-rated plant capacity (2011$) and the incremental levelized cost of energy including transportation and storage to be $42.3 per MWh (2011$).[224]

Modeling performed by Charles River Associates ("CRA") for CATF using updated assumptions including 45Q shows that more than 10 GW of existing available coal-fired capacity in the Western United States can cost-effectively retrofit with CCS at some level by 2030.[225] Analysis by ICF for NRDC and CATF also shows that with 45Q, roughly 14 GW of existing available coal capacity in the Western United States could economically retrofit with CCS at some level—after accounting for roughly 3 GW of potential retirements based on recent announcements, roughly 11 GW of existing available capacity remains.[226]

Emission Reductions: CCS on existing coal generating units has the potential to yield significant carbon pollution reductions. In its January 2017 Reconsideration Denial, EPA estimated that 90% CCS applied to 20% of fossil steam units could yield an 18% CO_2 emission rate reduction

---

[221] *See* Comments of the Natural Resources Defense Council and the Clean Air Task Force on EPA's 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, Comments focused on CCS (Oct. 31, 2018).
[222] *Id.*
[223] *See* Kristin Gerdes, *NETL Studies on the Economic Feasibility of the CO_2 Capture Retrofits for the U.S. Power Plant Fleet*, U.S. Dep't of Energy (Jan. 9, 2014), http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/NETL-Retrofits-Overview-2014-01-09-rev2.pdf.
[224] CATF, John Thompson, Cost Analysis of Capture Costs with Alternative Steam Supply (October 2018) at 11, 16, http://catf.us/resources/other/CCS_Cost_Development.pdf.
[225] CATF, *Impact of 45Q on Carbon Capture & Sequestration Deployment in the US Power Sector* (July 2018) at 8, 9, http://catf.us/resources/other/CATF_45Q_Analysis.pdf (showing 8 GW of CCS coal retrofits in Arkansas, Kansas, Texas, Oklahoma, and Missouri in 2030, accounting for partial capture on a total of 10.8 GW of available capacity).
[226] *See* Comments of the Natural Resources Defense Council and the Clean Air Task Force on EPA's 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, Comments focused on CCS (Oct. 31, 2018) at Appendix (showing CCS retrofits in states including Texas, New Mexico, Arizona, Montana, Nebraska, and Utah. The ICF analysis uses publicly available information and CCS assumption structure from EPA's IPM v6 documentation).

for fossil steam from 2012 levels.[227] The CRA modeling for CATF shows that CCS retrofits at existing coal-fired plants could cost-effectively reduce carbon pollution by roughly 46 million short tons per year in 2030.[228]

Arbitrariness of EPA's Analysis. The Proposed Rule's brief discussion of CCS relies heavily on EPA's determination in the CPP that CCS (or partial CCS) is "significantly more expensive than alternative options" and may not be viable for certain facilities. However, the Proposed Rule fails to note that EPA opted not to designate CCS as the BSER in the CPP because it had (correctly) determined that *generation-shifting would achieve comparable or greater emission reductions at lower cost.*[229] Indeed, the EPA expressly stated in the CPP that "co-firing and CCS measures are technically feasible and within price ranges that the EPA has found to be cost-effective in the context of other GHG rules, that a segment of the source category may implement these measures, and that the resulting emission reductions could be significant."[230] Now that EPA has proposed to discard the far more cost-effective and environmentally effective approach reflected in the CPP, the basis for its prior rejection of CCS no longer exists. It therefore must revisit its conclusions about the cost-effectiveness and feasibility of CCS, and consider whether CCS might be the BSER for all or some "segment of the source category" as discussed in the CPP.[231]

Moreover, the Proposed Rule arbitrarily fails to acknowledge more recent information considered by EPA in its 2017 denial of reconsideration of the Clean Power Plan as well as information submitted by EDF and other commenters in response to the ANPR. The 2017 Reconsideration Denial, for example, described several recent commercial-scale CCS retrofit projects for steam EGUs; cited a Carnegie Mellon study concluding that up to 60 GW of coal-fired generation (20% of the coal-fired fleet) might be amenable to CCS; and provided an extensive discussion of the geographic availability of CCS concluding that "opportunities to store captured CO_2 are widely available across the country."[232] The Proposed Rule also does not consider how policy changes since the finalization of the CPP, most notably the enactment of the 45Q tax credits, have improved the economics of CCS. Recent analyses indicate that 45Q tax credit could spur substantial additional investments in CCS in the United States, making it far more feasible and cost-effective to undertake these projects than before.[233]

---

[227] *See* CPP Reconsideration Denial: Appendix 3, at 16 tbl. 5.
[228] CATF, Impact of 45Q on Carbon Capture & Sequestration Deployment in the US Power Sector (July 2018) at 7, http://catf.us/resources/other/CATF_45Q_Analysis.pdf.
[229] CPP, 80 Fed. Reg. at 64,727-28.
[230] *Id.*
[231] *See Fed. Commc'ns Comm'n v. Fox Television Stations*, 556 U.S. 502, 537 (2009) (Kennedy, J., concurring) ("Where there is a policy change the record may be much more developed because the agency based its prior policy on factual findings. In that instance, an agency's decision to change course may be arbitrary and capricious if the agency ignores or countermands its earlier factual findings without reasoned explanation for doing so. An agency cannot simply disregard contrary or inconvenient factual determinations that it made in the past, any more than it can ignore inconvenient facts when it writes on a blank slate.").
[232] CPP Reconsideration Denial: Appendix 3, at 6.
[233] *See* Simon Bennett & Tristan Stanley, *U.S. Budget Bill May Help Carbon Capture Get Back on Track*, International Energy Agency, (Mar. 12, 2018), https://www.iea.org/newsroom/news/2018/march/commentary-us-budget-bill-may-help-carbon-capture-get-back-on-track.html ("IEA analysis suggests it could trigger the largest surge in carbon capture investment of any policy instrument to date. . . . This would increase total global carbon capture by around two thirds and, by incentivizing industry to find the lowest-cost projects, could be cheaper than projects already operating around the world.").

EPA's prior analyses, in addition to the information above, indicate that CCS is adequately demonstrated and feasible for, at a minimum, a significant number of steam EGUs—particularly EGUs that are close to CO_2 pipeline infrastructure or geologic sequestration sites, and that are in a position to take advantage of tax incentives for CCS. Moreover, CCS would achieve far greater emission reductions than HRI and would have significant co-benefits in the form of reduced non-GHG pollution. Rather than arbitrarily rely on its prior comparison of CCS with the CPP BSER, EPA must carefully evaluate CCS with respect to the statutory factors in section 111(a)(1).

D. On-Site Integration and Utilization of Renewable Energy Technologies

As discussed in comments we filed in response to the ANPR, power companies have been demonstrating on-site renewable energy integration and co-location with fossil fuel-fired generation for the past decade, and EPA should explore this option for reducing carbon pollution at coal-fired EGUs.[234] Even though we submitted comments on this option in response to the ANPR, EPA completely ignored it in the Proposed Rule.

Concentrated Solar Power ("CSP") is currently one of the renewable energy technologies with the highest potential for integration with existing fossil fuel-fired power plants. The two types of CSP technology that are available for integration are: (1) parabolic trough power plants, which consist of a solar field filled with hundreds or thousands of solar collector assemblies, and (2) power tower systems, where a large number of flat, sun-tracking mirrors known as heliostats focus sunlight onto a receiver at the top of a tall tower. A heat transfer fluid heated in the receiver is used to heat a working fluid, which is then used in a conventional turbine generator to produce electricity.

A study by DOE's National Renewable Energy Laboratory ("NREL") showed that, in 16 states, parabolic trough CSP technology could contribute about 1% to total annual energy generation at fossil-fired plants and power towers could contribute up to 2.2%.[235] NREL found that the potential carbon pollution avoided in those 16 states was as much as 23.5 million metric tons per year at existing coal-fired plants.[236] In addition to reducing carbon pollution emissions, parabolic trough and power tower augmentation were projected to contribute to lower SO_2 and NO_x emissions.[237]

One demonstration of renewable energy integration is the Colorado Integration Solar Project.[238] The project was a hybrid CSP/coal plant using parabolic trough solar technology. A parabolic trough solar field provided thermal energy to produce supplemental steam for power generation at Xcel Energy's Cameo Station's Unit 2 (approximately 2 MW equivalent) in order to decrease the overall consumption of coal, reduce emissions from the plant, improve plant efficiency, and

---

[234] EDF ANPR Comments at 55.

[235] National Renewable Energy Laboratory ("NREL"), *Solar-Augment Potential of U.S. Fossil-Fired Power Plants* (Feb. 2011), https://www.nrel.gov/docs/fy11osti/50597.pdf. The NREL study followed up on a 2009 study by the Electric Power Research Institute ("EPRI") and examined the use of CSP to augment power at fossil fuel-fired plants in 16 states in the southeast and southwest.

[236] NREL *Solar-Augment Potential of U.S. Fossil-Fired Power Plants* at 20 tbl. 6 & fig. 8.

[237] *Id.*

[238] *See* CPP Reconsideration Denial: Appendix 3, at 11.

test the commercial viability of CSP integration. The plant was used for testing purposes until the coal plant was retired and the CSP plant was decommissioned.[239]

Co-located renewable energy resources also provide a unique opportunity for fossil fuel-fired EGUs to take advantage of renewable energy generation. One example of such a project is Tampa Electric Company's Big Bend Solar facility, which began commercial operation in February 2017 and includes a 23 MW solar PV array adjacent to Tampa Electric's Big Bend Power Station.[240] Tampa Electric's Big Bend Solar facility is expected to provide environmental savings of up to 30,000 tons of CO_2 every year.[241] Another example is Xcel Energy's Comanche Solar Project, which became operational in 2016 and includes a 156 MW_{dc}/120 MW_{ac} solar project located next to Xcel's Comanche Generating Station.[242] The Comanche Solar Project has a 25-year power purchase agreement with Xcel Energy. The agreement was awarded as part of a competitive bid process where the project was found to be more cost-effective than natural gas on a dollar per megawatt hour basis.[243] Xcel's Comanche Solar Project is expected to result in 3.5 million tons of CO_2 reduction over its lifecycle.[244]

As explained in the Joint Environmental Comments on the BSER and Other Issues, EPA's proposal to apply the "redefining the source" policy from the PSD permitting context to the determination of the BSER in the present rulemaking is unlawful and arbitrary. Even if the policy did apply, however, EPA's administrative precedent makes clear that the policy does not categorically preclude the consideration of integrated renewable energy.[245]

E. <u>Coal Rank Improvements and Drying</u>

As already discussed in comments we filed in the ANPR record, coal rank improvements and drying can contribute to lower carbon pollution and should be considered by EPA.[246]

Coal-fired power plants generally burn one of three types of coal: lignite, sub-bituminous, and bituminous. These different coal types or ranks have different properties (such as heating value, carbon and moisture content) that affect the carbon emission intensity of the coal. In general, lignite emits more carbon pollution per unit of heat input, followed by sub-bituminous coal, and bituminous coal with averages of 216.3, 211.9, and 205.3 lbs CO_2/MMBtu, respectively.[247] In

[239] *Id.*
[240] *Id.* at 12.
[241] Tampa Electric, *Tampa Electric Completes Bay Area's Largest Solar Project* (Feb. 15, 2017), http://www.tampaelectric.com/company/mediacenter/article/index.cfm?article=897.
[242] *See* CPP Reconsideration Denial: Appendix 3, at 12.
[243] *See id.*
[244] *See* Community Energy Solar, *Comanche Solar*, https://communityenergysolar.com/project/comanche-solar/; NovatusEnergy, *Novatus Energy Acquires the 156 MW Comanche Solar Project in Colorado* (May 16, 2017), http://www.novatusenergy.com/novatus-energy-acquires-the-156-mw-comanche-solar-project-in-colorado/.
[245] *See In re La Paloma Energy Center*, 16 E.A.D. 267, 289-92 (EAB Mar. 14, 2014) (upholding regional office's determination that integration of solar power into a NGCC facility would "redefine the source," but basing the decision on technical and geographic considerations unique to the facility and emphasizing that such determinations require a detailed case-by-case analysis).
[246] EDF ANPR Comments at 57.
[247] EPA, Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Coal-Fired Electric Generating Units (Oct. 2010).

addition, due to the inherent moisture in sub-bituminous and lignite coals, all else being equal a bituminous coal-fired boiler is more efficient than a corresponding boiler burning sub-bituminous or lignite coal. Therefore, switching from a low to a high-rank coal will lower emissions.[248]

In its 2010 report on available and emerging technologies for reducing greenhouse gas emissions from coal-fired EGUs, EPA listed coal drying as a CO_2 control technology for coal plants.[249] According to EPA, while low-rank coals are often used because of their low cost per unit of heat input relative to bituminous coal and their low sulfur content, their high moisture content—typically 25 to 40% with lignite having the highest moisture content—can be a major disadvantage.[250] EPA explained that "[a]s fuel moisture decreases, the heating value of the fuel increases so that less coal needs to be fired to produce the same amount of electric power. Drier coal is also easier to handle, convey, and pulverize—reducing the burden on the coal-handling system. In addition, an EGU boiler designed for dried coal is also smaller and has lower capital costs than a comparable EGU designed to burn coal that has not been dried."[251] According to EPA, "[t]he pre-combustion drying of low-rank coals can improve overall efficiency and several advanced coal drying technologies are or nearly are commercially available."[252]

One such example is Great River Energy which developed the DryFining technology. The technology, which uses waste heat to dry coal in a fluidized bed dryer, has been in commercial-scale operation in Units 1 and 2 at Great River Energy's Coal Creek Plant since December 2009. The technology can reduce coal moisture from 38% to 29%, increasing the energy content of lignite from 6,200 to more than 7,000 BTU/lb and reducing fuel input.[253] This in turn increases the unit's net heat rate by 4% with a corresponding 4% decrease in carbon pollution emissions. The DryFining technology also allows for separation of denser material such as pyrites from the coal, thereby improving the quality of coal fed to the boiler and reducing emissions of mercury, SO_2, and NOx. The technology is reported to have reduced operating costs at Coal Creek by more than $18 million per year.[254]

Another example is RWE Power in Germany, which developed a fluidized bed drying technology for lignite, called WTA. A prototype commercial-scale drying plant using this process began operation in 2009 at the utility's Nederaussem Power Station site, with net gains in cycle efficiency on the order of 4 percentage points reported.[255]

---

[248] *Id.*
[249] *Id.*
[250] *Id.*
[251] *Id.* at 32.
[252] *Id.*
[253] *Id.*; *see also* Nigel Dong, IEA Clean Coal Centre, *Techno-Economics of Modern Pre-Drying Technologies for Lignite-Fired Power Plants* (Aug. 2014), https://www.usea.org/sites/default/files/082014_Techno-economics%20of%20modern%20pre-drying%20technologies%20for%20lignite-fired%20power%20plants_ccc241.pdf; Sandra Broekema, *Innovative Coal Drying Process Benefits Power Plant* (October 25, 2017), https://www.processingmagazine.com/innovative-coal-drying-process-benefits-power-plant/.
[254] *See* Sandra Broekema, *Innovative Coal Drying Process Benefits Power Plant*.
[255] EPA, Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Coal-Fired Electric Generating Units, at 33 (Oct. 2010); *see also* IEA Clean Coal Centre, Nigel Dong, *Techno-Economics of Modern Pre-Drying Technologies for Lignite-Fired Power Plants*.

Other coal drying technologies for low-rank coals in various stages of development include attrition milling of coal followed by air drying, compressing heated coarse crushed coal to squeeze out water, and heating wet coal under pressure.[256]

F. <u>In Light of the Alternatives Above, EPA's Determination that Heat Rate Improvements Are BSER Is Arbitrary and Violates the Statutory Mandate to Identify the *Best* System of Emission Reduction.</u>

As we discuss in more detail in the Joint Environmental Comments on BSER issues, and in light of the alternative pollution reduction measures described above, EPA's determination that heat rate improvements are the best system of emission reduction is arbitrary and capricious and violates the statutory mandate to identify the *best* system.

As EPA has previously determined, the "quantity of emission reductions achievable through heat rate improvement measures [is] insufficient for these measures alone to constitute the BSER."[257] Several expert analyses have also shown that policy approaches based on coal heat rate improvements alone would result in increased utilization of coal plants and associated increases in emissions—also known as the "rebound effect." According to a recent paper by Resources for the Future, a policy approach based only on measures such as coal HRI would result in minimal improvements in carbon pollution and increases in sulfur dioxide pollution at the national level compared to no policy at all.[258] The paper also shows that carbon pollution would increase in some states compared to a no-policy reference case since any emission reductions from heat rate improvements are more than offset by increased coal generation, which drives up emissions.

In fact, EPA's own modeling shows that the Proposed Rule would result in minimal nationwide reductions in carbon pollution compared to a base case with no policy and could increase carbon pollution in as many as 17 states in 2030.[259] In addition, many states could see an increase in harmful pollution that contributes to soot and smog. According to EPA's own analysis, sulfur dioxide and nitrogen oxide pollution could increase in as many as 19 states in 2030 compared to a base case with no policy.[260]

EPA has a legal obligation to establish carbon pollution limits that achieve maximum feasible pollution control and protect the public from the urgent threat of climate change. The record already shows that heat rate improvement is not the best system of emission reduction for power plants. EPA's selection of heat rate improvement as BSER in the Proposed Rule violates the

---

[256] EPA, Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Coal-Fired Electric Generating Units, at 33.
[257] CPP 80 Fed. Reg. at 64,745.
[258] Amelia T. Keyes, *et al*., Resources for the Future, Carbon Standards Examined: A Comparison of At-the-Source and Beyond-the-Source Power Plant Carbon Standards (Aug. 2018), http://www.rff.org/files/document/file/RFF%20WP%2018-20.pdf.
[259] EPA, ACE RIA (using IPM State-Level Emissions: Illustrative No CPP and IPM State-Level Emissions: Illustrative 4.5 percent HRI at $50/kW modeling output files); *See also* Rama Zakaria, *The Trump administration's Clean Power Plan replacement – for many states, worse than nothing, http://blogs.edf.org/climate411/2018/09/14/the-trump-administrations-clean-power-plan-replacement-for-many-states-worse-than-doing-nothing/* (Sept. 14, 2018).
[260] *Id.*

statutory mandate to identify the *best* system and would increase climate and health-harming pollution in many states and endanger the health and well-being of Americans.

II. EPA HAS UNLAWFULLY AND ARBITRARILY OVERLOOKED POLLUTION REDUCTION OPPORTUNITIES FOR NGCC THAT MEET THE BSER CRITERIA.

As we discuss in more detail in the Joint Environmental Comments on BSER Issues,[261] section 111 clearly directs EPA to ensure the establishment of standards of performance for "any existing source" that would be subject to a section 111(b) standard if it were a new source. Because new and reconstructed NGCC units are subject to standards of performance for carbon pollution under section 111(b), EPA *must* produce emission guidelines that ensure existing NGCC sources will be subject to standards of performance under section 111(d). Yet the Proposed Rule utterly fails to address existing NGCC, even though NGCC represent a large and growing share of existing EGU capacity, generation, and carbon pollution.

EPA suggests in the Proposed Rule that it lacked sufficient information to designate a BSER for NGCC. Despite the extensive comments we filed in the ANPR record, EPA fails to consider pollution reduction opportunities for NGCC that meet the BSER criteria. The utilization of NGCC units has increased over the past few years due in large part to the increased availability and low cost of natural gas. In fact, since 2015 the average utilization of NGCC units has exceeded that of coal-fired EGUs.[262] With higher utilization, NGCC units will experience more frequent maintenance intervals and may find investment in improvements more economically attractive than in the past when capacity factors were lower.[263]

A. <u>Heat Rate Improvement (HRI)</u>

As discussed in comments we filed in the ANPR record, heat rate or efficiency improvements at existing NGCC units are an adequately demonstrated and cost-effective way of reducing carbon pollution from those units.[264] A new report by Andover Technology Partners finds total cost-effective NGCC heat rate improvements on the order of 6% or more may be possible.[265] The new report builds on and updates a previous 2016 report by Andover that we submitted in the ANPR record.[266]

Turbine inlet cooling and intercooling: According to Andover, one promising approach to improving the heat rate of gas turbines involves turbine inlet cooling ("TIC") and related technologies, such as wet compression. These technologies have been installed at over 400 facilities, with about half in the United States.[267] While the benefits are greatest in warm climates, these technologies have also been installed in more moderate climates.

---

[261] Joint Environmental Comments on BSER Issues § 6.
[262] Andover Technology Partners, Improving Heat Rate on Combined Cycle Power Plants, at 7 (Oct. 3, 2018)
[263] *Id.*
[264] EDF ANPR Comments at 58.
[265] Andover Technology Partners, Improving Heat Rate on Combined Cycle Power Plants, at 3 (Oct. 3, 2018).
[266] Andover Technology Partners, Improving Heat Rate on Combined Cycle Power Plants (Dec. 2016).
[267] Andover Technology Partners, Improving Heat Rate on Combined Cycle Power Plants, at 3 (Oct. 3, 2018).

Turbine inlet cooling technologies can be deployed quickly and have low capital costs. According to Andover, TIC can yield NGCC heat rate improvements in the range of 2% with capacity increases of 6% to 11% at capital costs from $0.9 to $19/kW.[268] If dispatch considerations are accounted for, the overall effect on heat rate is even higher because increased capacity from TIC is achieved more efficiently than increased capacity from the use of Heat Recovery Steam Generator duct burners or less efficient simple cycle peaking capacity or steam EGUs—in other words the increase in NGCC plant output from TIC can be used to displace less fuel efficient methods of increasing generating output.[269]

While TIC is estimated to already have a significant market penetration, there is still a long way to go so that more improvements are possible. Using the Turbine Inlet Cooling Association database, Andover estimates that TIC is installed on roughly 48.5 GW of capacity as part of NGCC systems in 20 states that were determined to be most attractive for TIC.[270] Andover estimates that there remains roughly 100 GW of gas turbine capacity installed in combined cycle arrangements that could be retrofit with TIC in those 20 states.[271] When combined with NGCC capacity in the remaining 30 states, Andover finds that in total, close to 130 GW of gas turbine capacity in NGCC arrangements could potentially be retrofit with TIC in the entire United States.[272]

Gas turbine upgrades: Another promising approach that is offered by various turbine manufacturers and aftermarket suppliers involves upgrading gas turbine components. Older turbines can benefit from replacement of existing components with newer components with improved designs or materials that offer the potential for heat rate improvements over the original equipment. For instance, General Electric has developed improved wire brush seals for the compressor shaft that can increase output by about 1% and improve heat rate by about 0.5%.[273] Replacing high pressure packing seals on the turbine with brush seals can also improve performance, typically 0.3% in output and 0.2% heat rate.[274] Another option involves installing higher flowrate inlet guide vanes which can boost power and improve heat rates by approximately 1%.[275] Andover estimates that gas turbine upgrades can achieve NGCC heat rate improvements on the order of 3% depending upon the circumstances with capacity increases of roughly 13% at a capital cost of $172 per kW—a fraction of what new capacity costs.[276]

Steam turbine upgrades: In addition to improving the heat rate of the gas turbine, there are also several approaches that can be used to improve the heat rate of the steam system. These include steam turbine upgrades or overhauls, condenser cleaning, and rebuilding of feed pumps.[277]

---

[268] *Id.* at 4.
[269] *See Id.* at 19-21 (showing that by dispatching TIC to meet load prior to using duct burners, overall operating heat rate is lower over the full dispatch range and CO_2 emissions can be reduced by about 30%).
[270] *Id.* at 21-22.
[271] *Id.*
[272] *Id.*
[273] *Id.* at 22.
[274] *Id.*
[275] *Id.* at 25.
[276] *See id.* at 4, 25 (new combustion turbine capacity is at $680/kW to $1,107/kW and combined cycle is at $982/kW to $1,108/kW).
[277] *Id.* at 3.

Installing variable speed drives for pumps and fans can also improve heat rates by reducing parasitic load.[278] There are also operating and maintenance practices that help minimize losses in the steam system. Andover estimates that steam turbine upgrades can achieve NGCC heat rate improvements on the order of 3.2% with capacity increases of roughly 3% at a capital cost of $130 per kW.[279]

According to Andover, the opportunity for upgrading gas and steam turbine systems at NGCC plants is growing. Within a few years, well over half of the currently installed base of NGCC plants will be in excess of 20 years old.[280] This means that worn out or dated equipment can be replaced with newer equipment with potentially improved technology. While the total heat rate improvement possible for any facility will vary depending upon its circumstances, as shown in Table 1 below, Andover finds that through gas turbine upgrades, steam turbine upgrades, and TIC about 6% or greater heat rate improvement may be possible.[281]

Table 1. Approximate heat rate improvement, capacity increase and capital cost (2017$) relative to NGCC plant heat rate, capacity and total NGCC plant output[282]

Technology	Approx. NGCC HRI %	Capacity Increase %	Capital Cost $/kW
Inlet Fogging	2.0%	6%	$0.93
Wetted Media	2.0%	6%	$0.90
Wet Compression	1.3%	11%	$10
Inlet Chiller	2.0%	11%	$19
Gas Turbine Upgrade	3.0%	13%	$172
Steam Turbine Upgrade	3.2%	3%	$130

B. Other Non-HRI Pollution Reduction Measures

Carbon Capture and Storage: As discussed in section I.C. above, CCS is adequately demonstrated and has been successfully implemented at multiple projects around the world during the past few decades. In 2014, NETL estimated the cost of capture to be close to $90 per metric ton of CO_2 at an existing natural gas combined cycle plant.[283] Since then, CCS costs have continued to decline and recent 45Q tax credit legislation has made CCS even more cost-effective. Recent analysis by CATF estimates the total overnight capital cost of CCS retrofits at existing NGCC plants to be $719 per net kW of de-rated plant capacity (2011$) and the incremental levelized cost of energy including transportation and storage to be $22.8 per MWh

---

[278] *Id.*
[279] *Id.* at 4.
[280] *Id.* at 3.
[281] *Id.* at 3, 30.
[282] *Id.* at 4.
[283] *See* Kristin Gerdes, *NETL Studies on the Economic Feasibility of the CO_2 Capture Retrofits for the U.S. Power Plant Fleet*, U.S. Dep't of Energy (Jan. 9, 2014), http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/NETL-Retrofits-Overview-2014-01-09-rev2.pdf.

(2011$).[284] Modeling performed by CRA for CATF using updated assumptions including 45Q shows that more than 9 GW of existing available gas capacity in the Western United States can cost-effectively retrofit with CCS at some level yielding carbon pollution reductions of more than 8 million short tons per year in 2030.[285]

On-site integration and utilization of renewable energy technologies: As discussed in section I.D.1. above, power companies have been experimenting with on-site renewable energy integration and co-location with fossil fuel-fired generation for the past decade, and EPA should explore this option for reducing carbon pollution at NGCC units.[286] NREL's study on the solar-augment potential of U.S. fossil-fired power plants found that the potential carbon pollution avoided at existing NGCC units in 16 states was as much as 6.61 million metric tons per year.[287] One demonstration of renewable energy integration is the Florida Power and Light Martin Next Generation Solar Energy Center.[288] This 75 MW project uses parabolic trough technology and is the first hybrid solar facility in the world to connect to an existing natural gas combined cycle power plant. Construction began in December 2008 and was completed in 2010 and the facility continues to operate today.[289] Another example of co-locating renewable energy resources is the Clean Path Energy Center project which involves a 680 MW natural gas combined cycle and a 70 MW solar photovoltaic (PV) array.[290]

III. EPA MUST CONSIDER NOT ONLY THESE EMISSION REDUCTION OPPORTUNITIES IN ISOLATION, BUT ALSO MUST CONSIDER HOW THE SOURCE CATEGORY CAN BE SUBCATEGORIZED AND HOW EMISSION REDUCTION OPPORTUNITIES CAN BE COMBINED TO ACHIEVE MAXIMUM FEASIBLE CONTROL.

In considering systems of emission reduction, EPA must evaluate all "reasonable alternatives"[291] and must make a "reasonable effort to develop the facts" rather than base its decisions on a "guess about what the facts might be."[292] Accordingly, EPA must consider all the emission reduction systems discussed in detail above. The Agency must also consider how source categories can be subcategorized and how systems can be combined to achieve maximum feasible control.

[284] CATF, John Thompson, Cost Analysis of Capture Costs with Alternative Steam Supply (October 2018) at 12, 17, http://catf.us/resources/other/CCS_Cost_Development.pdf.
[285] CATF, *Impact of 45Q on Carbon Capture & Sequestration Deployment in the US Power Sector* (July 2018) at 7, 8, 9, http://catf.us/resources/other/CATF_45Q_Analysis.pdf (showing close to 3 GW of CCS gas retrofits in California, Texas, and Oklahoma in 2030, accounting for partial capture on a total of 9.6 GW of available capacity).
[286] EDF ANPR Comments at 55.
[287] National Renewable Energy Laboratory, *Solar-Augment Potential of U.S. Fossil-Fired Power Plants* (Feb. 2011), https://www.nrel.gov/docs/fy11osti/50597.pdf.
[288] *See* CPP Reconsideration Denial: Appendix 3, at 11.
[289] *Id.*; *see also* Florida Power & Light, *Solar Energy Centers*, https://www.fpl.com/clean-energy/solar/energy-centers.html.
[290] *See* CPP Reconsideration Denial: Appendix 3, at 11.
[291] *Del. Dep't of Nat. Res. v. EPA*, 785 F.3d 1, 18 (D.C. Cir. 2015) ("Because EPA too cavalierly sidestepped its responsibility to address reasonable alternatives, its action was not rational and must, therefore, be set aside.") (citations omitted).
[292] *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 531 (D.C. Cir. 1983).

A. Coal-Fired EGUs

As discussed in detail in section I above, carbon pollution reduction measures such as natural gas co-firing and CCS are adequately demonstrated at existing coal-fired EGUs and should be considered by EPA as part of any emission reduction system. In addition to evaluating each of these technologies in isolation, EDF has also assessed how these technologies could be combined and applied to different segments of the power sector to yield deeper emission reductions. We explain this assessment below.[293,294]

First, we examined the potential to cost-effectively deploy CCS in the existing fleet. Results from CCS modeling performed by CRA for CATF and ICF analysis for NRDC and CATF, show that it is not only technically feasible but also cost-effective for over 10 GW of existing available coal-fired capacity in the Western United States to retrofit with CCS at some level in the presence of 45Q tax credits.[295] Using the 2018 existing coal fleet and relying on both CRA and ICF results showing states where CCS retrofits could be economically feasible, together with 2015 operational data and CATF CCS costs as well as 45Q tax credits, we estimate close to 115 million short tons of potential emission abatement or 7.7% reduction below 2015 levels at *negative* cost in 2030.[296] Using information from CATF's study mapping existing coal plants to saline storage and oil and gas fields, we find that states where CCS retrofits were found to be cost-effective in the presence of 45Q have coal plants that are as far as 100 miles from the center of a basin.[297] As discussed in section I above, CATF's study also shows that 90% of existing coal plants are within 100 miles from the center of a basin with adequate capacity and more than half of the plants are less than 10 miles from the center of a basin.[298] Given our reliance on modeling results and analysis of economic feasibility, the CCS retrofit potential we use in our analysis is conservative and we would expect greater CCS retrofit potential to be technically feasible.

[293] Our analysis assumes that EGUs operate at the same output levels as they did before the application of the carbon pollution reduction measures (i.e. our analysis does not assess the impact of these measures on dispatch). The abatement costs we estimate are not intended to reflect compliance costs, which would depend on the compliance options available to the EGUs and the economics of alternative strategies. Where unit-level data was not available, we based the applicability of an emission reduction measure on estimates of the percent of the fleet to which it was applicable based on the identified literature.

[294] Our analysis uses the following financial assumptions based on EPA's IPM v6 documentation: discount rate of 5.81%; plant modification book life of 20 years; plant modification annuity factor of 11.7; plant modification capital charge rate of 8.58%; annual inflation rate of 1.83%.

[295] *See* CATF, *Impact of 45Q on Carbon Capture & Sequestration Deployment in the US Power Sector* (July 2018), http://catf.us/resources/other/CATF_45Q_Analysis.pdf; *See also* Comments of the Natural Resources Defense Council and the Clean Air Task Force on EPA's 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, Comments focused on CCS at Appendix (Oct. 31, 2018).

[296] *See* CATF, John Thompson, Cost Analysis of Capture Costs with Alternative Steam Supply (October 2018), http://catf.us/resources/other/CCS_Cost_Development.pdf. Using CATF CCS retrofit capital cost of $1,1190 per net kW de-rated capacity (2011$), variable costs based on deteriorated heat rate and EIA AEO 2018 fuel cost projections, CATF CO_2 transportation and storage costs, and 45Q tax credits.

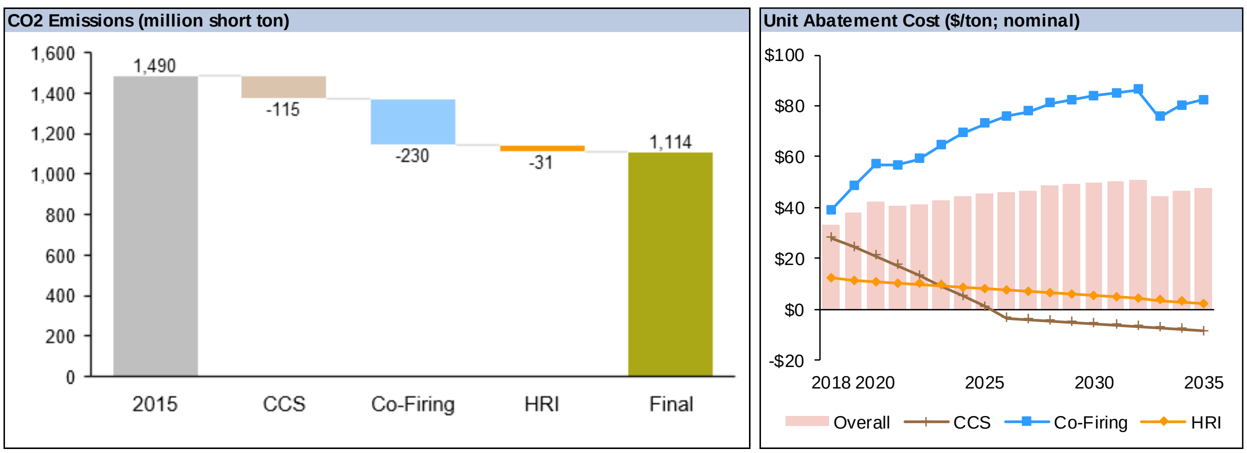
[297] *See* Comments of the Natural Resources Defense Council and the Clean Air Task Force on EPA's Proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program, Comments focused on CCS (Oct. 31, 2018).

[298] *Id.*

Using MJB&A's natural gas co-firing analysis and applying 50% co-firing to the remaining existing coal fleet—after accounting for coal-fired capacity that we estimated could retrofit with CCS—we find that close to 40% of the total 2015 coal generation is amenable to co-firing based on natural gas pipeline proximity and availability.[299] This yields close to 230 million short tons of additional abatement or a total of 23% emission reduction below 2015 levels from combined CCS retrofit and natural gas co-firing at an average cost of $54 per ton (nominal$) or $42 per ton (2016$) in 2030.[300,301] As discussed in section I above, the co-firing costs we use are conservative and we would expect costs to be lower.

Adding 4.5% heat rate improvement to the remaining existing coal fleet at $100/kW yields 31 million short tons of additional abatement or a combined total of 25% emission reduction—or 25% emission rate reduction—below 2015 levels from CCS retrofit, natural gas co-firing, and heat rate improvements at an average cost of $50 per ton (nominal$) in 2030 or $39 per ton (2016$) in 2030.[302,303]

Figure 3: Estimate of Emission Abatement and Cost from Pollution Reduction Measures at Coal-Fired EGUs



Including the potential for renewable energy integration at coal-fired capacity that does not retrofit with CCS or co-fire with natural gas using information from NREL's study on the solar-augment potential of U.S. fossil-fired power plants and improving coal rank in the remaining

---

[299] *See* MJB&A Natural Gas Pipeline Analysis. (The co-firing cut-off percentage used here means that co-firing is applied only to coal-fired EGUs that were found in the original MJB&A pipeline analysis to co-fire at levels higher than or equal to this percentage.)
[300] *See Id.*
[301] Deflating nominal$ in 2030 to real 2016$ using 1.83% annual inflation rate.
[302] *See* EPA, GHG Abatement Measures Technical Support Document (August 2015); *See also* ACE RIA (variable costs based on fuel cost savings and EIA AEO 2018 fuel price projections); *see also* Comments of Sierra Club on EPA's 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 (Oct. 31, 2018) (finding 7.43% heat rate improvement based on 95th percentile lowest rolling annual average and 2017 annual average).
[303] Deflating nominal$ in 2030 to real 2016$ using 1.83% annual inflation rate.

fleet from lignite or subbituminous to bituminous could yield close to 20 million short tons of additional abatement.[304]

B. <u>NGCCs</u>

As discussed in detail in section II above, carbon pollution reduction measures such as heat rate improvement at existing NGCC units and CCS are adequately demonstrated and should be considered by EPA as part of any emission reduction system.

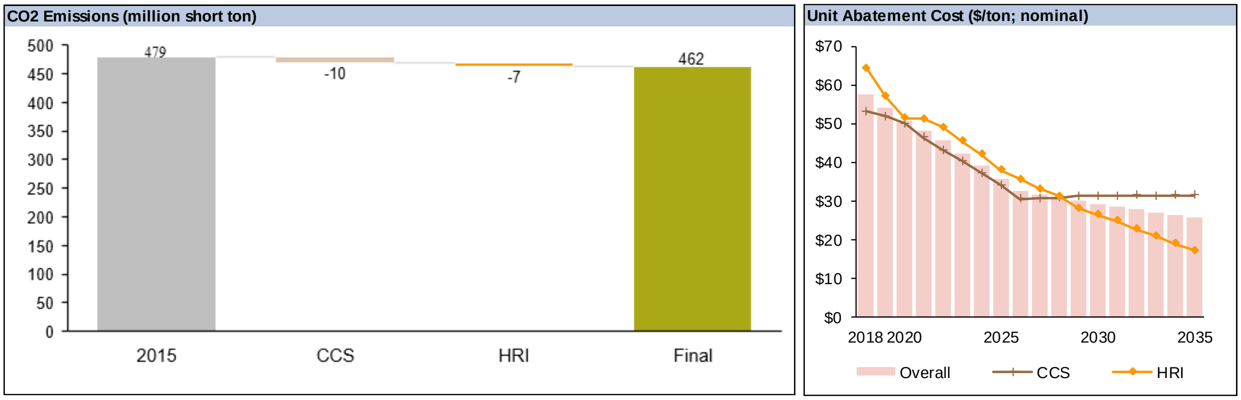
Using results from CCS modeling performed by CRA for CATF which shows that it is not only technically feasible but also cost-effective for more than 9 GW of existing available gas capacity in the Western United States to retrofit with CCS at some level in the presence of 45Q—together with 2015 operational data and CATF CCS costs as well as 45Q tax credits, we estimate roughly 10 million short tons of emission abatement or 2% reduction below 2015 levels at a cost of $31 per ton (nominal$) or $24 per ton (2016$) in 2030.[305,306]

As already discussed in section II above, based on Andover Technology Partners' new report, a total of 6% or more NGCC heat rate improvement may be possible through TIC, gas turbine and steam upgrades.[307] Using 2015 operational data and applying 2% heat rate improvement from TIC to the remaining existing NGCC fleet and combining with additional heat rate improvements from gas and steam turbine to reach a total of 6% heat rate improvement, yields approximately 7 million short tons of additional abatement or a total of 3.6% emission reduction—or 3.6% emission rate reduction—below 2015 levels from combined CCS retrofits and heat rate improvements at an average cost of $29 per ton (nominal$) or $22 per ton (2016$) in 2030.[308,309]

---

[304] *See* National Renewable Energy Laboratory, *Solar-Augment Potential of U.S. Fossil-Fired Power Plants* (Feb. 2011), <u>https://www.nrel.gov/docs/fy11osti/50597.pdf</u> (using state-specific generation potential of power tower scaled to account for coal generation change between NREL study year and 2015); *see also* EPA, Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Coal-Fired Electric Generating Units (Oct. 2010), Exhibit 2-7 at 20 (5% improvement estimated for lignite to bituminous and 3% improvement estimated for sub-bituminous to bituminous using improvement in CO_2 emission factors on a heat input basis).
[305] *See* CATF, Impact of 45Q on Carbon Capture & Sequestration Deployment in the US Power Sector (July 2018), http://catf.us/resources/other/CATF_45Q_Analysis.pdf; *See also* CATF, John Thompson, Cost Analysis of Capture Costs with Alternative Steam Supply (October 2018), <u>http://catf.us/resources/other/CCS_Cost_Development.pdf</u>. Using CATF CCS retrofit capital cost of $719 per net kW de-rated capacity (2011$), variable costs based on deteriorated heat rate and EIA AEO 2018 fuel cost projections, CATF CO_2 transportation and storage costs, and 45Q tax credits.
[306] Deflating nominal$ in 2030 to real 2016$ using 1.83% annual inflation rate.
[307] *See* Andover Technology Partners, Improving Heat Rate on Combined Cycle Power Plants (Oct. 3, 2018).
[308] *See id.* (assuming turbine upgrade applicable to NGCC capacity represented by 50% of plants greater than 20 years of age and TIC applicable to only gas turbine part of NGCC capacity; using capital cost estimate of $33/kW per 1% HRI and variable costs based on fuel cost savings and EIA AEO 2018 fuel cost projections).
[309] Deflating nominal$ in 2030 to real 2016$ using 1.83% annual inflation rate.

Figure 3: Estimate of Emission Abatement and Cost from Pollution Reduction Measures at NGCC units



Including the potential for renewable energy integration at NGCC units that do not retrofit with CCS based on NREL's study on the solar-augment potential of U.S. fossil-fired power plants could yield an additional 5 million short tons of aggregate abatement.[310]

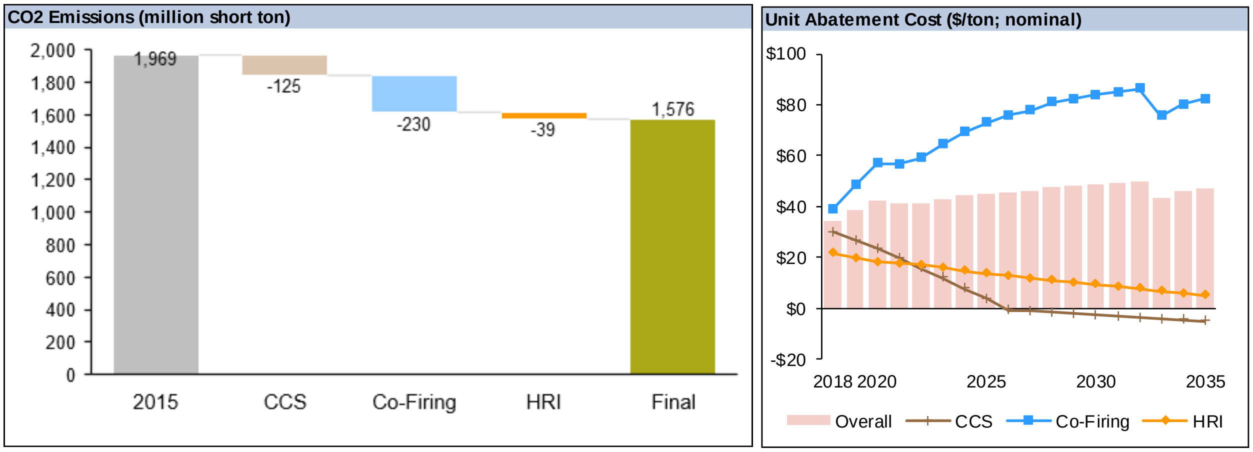
In sum, we find that the emission reduction systems discussed above—CCS retrofits, natural gas co-firing, and HRI at existing coal-fired EGUs together with CCS retrofits and HRI at existing NGCC units—could result in aggregate emission reductions of 393 million short tons across the existing coal and NGCC fleet or 20% reduction below 2015 levels at an average cost of $49 per ton (nominal$) or $38 per ton (2016$) in 2030.[311] This estimate of emission abatement is conservative and does not include additional abatement potential from coal rank improvements, renewable energy integration, or additional CCS retrofit opportunities. Yet this aggregate emission reduction estimate is significant and emphasizes the need for EPA to conduct a proper assessment of the *best* system of emission reduction at both coal-fired EGUs and NGCC units.

---

[310] *See* National Renewable Energy Laboratory, *Solar-Augment Potential of U.S. Fossil-Fired Power Plants* (Feb. 2011), https://www.nrel.gov/docs/fy11osti/50597.pdf.

[311] Deflating nominal$ in 2030 to real 2016$ using 1.83% annual inflation rate.

Figure 4: Estimate of Emission Abatement and Cost from Pollution Reduction Measures at Fossil-Fuel Fired EGUs



As already discussed in detail, all the emission reduction systems described here are adequately demonstrated and technically feasible. Our analysis also demonstrates the potential to apply different emission reduction systems to subcategories of source categories and combine systems to achieve maximum feasible emission reductions. EPA cannot simply rely on modest heat rate improvements at existing coal-fired EGUs that would yield minimal, if any, emission reductions—less than 30 million short tons in 2030—and neglect to consider other emission reduction systems that are available and feasible and could in aggregate yield much greater emission reductions.[312] These emission reductions are also achievable at abatement costs that are similar to those in the Proposed Rule.[313]

IV. EPA'S PROPOSED RESTRICTIONS ON AVERAGING AND TRADING ARE ARBITRARY AND UNLAWFUL, PARTICULARLY WHEN APPLIED TO EGUs.

These comments build upon and supplement the Joint Environmental Comments on Framework Regulations, which EDF has also joined. Here, we focus on why revisions to the 111(d) implementing regulations, together with aspects of the proposal specific to the implementation of ACE, would be particularly harmful in the context of section 111(d) limits on carbon pollution from electric generating units.

A. EPA's Proposed Restrictions on "Standards of Performance" Are Arbitrary and Lack Statutory Support.

1. The proposal to exclude allowances from the definition of standard of performance is arbitrary and unlawful.

EPA proposes to eliminate "allowance system" from the definition of "emission standard" (which EPA proposes to redesignate as "standard of performance") on the grounds that the

[312] ACE RIA tbl. 3-5 at 3-15 (comparing emissions under the Proposed Rule relative to No CPP base case).
[313] *Id.* tbl. ES-4 at ES-7, tbl. ES-6 at ES-8 (using compliance costs and emission abatement relative to No CPP base case for 2% HRI at $50/kW and 4.5% HRI at $100/kW illustrative scenarios yields $33 to $38/ton (2016$) in 2030).

reference to an allowance system is a "vestigial artifact."[314] EPA implies that such removal would be "[c]onsistent with the court's opinion" in *New Jersey v. EPA*,[315] in which the U.S. Court of Appeals for the District of Columbia Circuit vacated EPA's Clean Air Mercury Rule. But EPA's proposed revision is in no way mandated by the cited opinion, which neither references the definition of "emission standard" nor provides any other assessment of the availability of allowance systems under section 111(d). Indeed, it is telling that the ACE proposal does not actually cite or even name the opinion with which EPA claims to be acting "[c]onsistent[ly]."

Since EPA fatally misconstrues the only legal authority to which it even vaguely alludes, the Agency has not provided any legal grounds supporting its decision. EPA has also not provided any other reasons that such a change is necessary or beneficial. Its proposal is utterly unfounded, rendering it arbitrary and capricious. Below we explain why EPA's broader attacks on trading and averaging lack merit, and why trading and averaging are particularly useful when regulating carbon pollution from power plants. EPA must not attempt to unlawfully preclude averaging and trading through a wholly unsupported definitional revision.

2. <u>The proposal to require rate-based standards for ACE is arbitrary and unlawful and would undercut the effectiveness and purpose of § 111 to control pollution.</u>

EPA's proposed definition of "standard of performance" would allow the standard to take the form of "a legally enforceable regulation setting forth an allowable rate or limit of emissions into the atmosphere."[316] However, EPA has proposed that standards of performance under ACE must take a "rate-based" form, expressed in terms of a maximum allowable amount of carbon pollution per unit of output.[317] Under the Proposed Rule, EPA would not allow a state to submit a plan that establishes standards of performance in terms of a maximum allowable amount of pollution per year (either from individual EGUs or in aggregate)—even though such a limitation would unquestionably satisfy the statutory definition of a "standard of performance" and could result in equivalent or greater emission reductions compared to a rate-based standard. This restriction is arbitrary and unlawful.

EPA has provided no legitimate justification for requiring rate-based standards; the reasons that it provides fall flat. As its "primar[y]" reason, the Agency asserts that there is a "natural correspondence between" its proposed BSER and a rate-based standard. But "natural correspondence" does not appear in the statute; rather, EPA's responsibility under section 111 is to determine whether a state plan is "satisfactory,"[318] insofar as it establishes "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable" through the BSER.[319] Because a mass-based standard is clearly "a standard for emissions of air pollutants" that can "reflect[] the degree of emission limitation achievable" through the BSER as

[314] ACE, 83 Fed. Reg. at 44,773.
[315] 517 F.3d 574 (D.C. Cir. 2008).
[316] 40 C.F.R. § 60.21a(f) (proposed), 83 Fed. Reg. at 44,804.
[317] ACE, 83 Fed. Reg. at 44,764.
[318] 42 U.S.C. § 7411(d)(2)(A).
[319] *Id.* § 7411(a)(1).

well or better than the proposed rate-based standard,[320] it is arbitrary for EPA to preclude mass-based standards of performance based on its extra-statutory notion of a "natural correspondence" between its BSER and a rate-based standard. EPA's proposal is especially arbitrary since the preclusion of mass-based standards could undermine emission reductions by taking major pollution-reduction strategies off the table, despite the statute's command to reflect the "*best* system" (emphasis added).

Second, EPA suggests that requiring standards of performance to take the same form nationwide will create continuity across states, prevent ambiguity, and ensure as much simplicity as possible. This claim also fails to withstand scrutiny. Again, EPA identifies no reason that "continuity across states" in the form of standards, as opposed to the degree of stringency (which might facilitate trading or averaging and be more equitable[321]), is a valid factor to consider—it does not appear in the statute, and the Agency does not explain how it would further statutory purposes. Moreover, we show elsewhere in this document and the Joint Environmental Comments on BSER Issues that ACE could create extreme disparities across states on matters that directly implicate the statutory purpose, such as the degree and timing of emission reductions. In those areas, which directly implicate the Agency's core purpose, EPA should be concerned about continuity in order to ensure meaningful, near-term pollution reductions. EPA has failed to explain why continuity supports depriving states of a highly effective implementation option.

Nor does EPA provide any support for the claim that requiring rate-based standards would "prevent ambiguity." To the contrary, mass-based pollution limits have been used successfully by EGUs for decades. A clearly defined limit on the amount of carbon pollution a source may emit is no more ambiguous—and may be even clearer—than a rate-based goal. Similarly, EPA provides no support for its claim that mandating rate-based standards of performance "ensures as much simplicity as possible." Requiring rate-based standards will not necessarily create simplicity for sources, which are generally familiar with compliance under a mass-based standard. It will not create simplicity for states, many of which already utilize mass-based standards for carbon pollution from power plants—and which, in any event, could be permitted to choose between mass- and rate-based standards, at their preference. And it would not create simplicity for EPA, which has ample experience with mass-based standards. As EPA notes in the CPP, the Agency "received significant comment to the effect that mass-based allowance trading was not only highly familiar to states and EGUs, but that it could be more readily applied than rate-based trading for achieving emission reductions in ways that optimize affordability and electric system reliability."[322] EPA has offered nothing in the ACE proposal that effectively rebuts that observation. Below we cite several examples of CPP commenters who specifically highlighted the relative simplicity of mass-based trading programs.

The Proposed Rule also arbitrarily ignores the negative impacts of restricting standards of performance to rate-based standards. Compared to rate-based standards, mass-based standards offer significant advantages for public health and the environment—most notably, they provide a

[320] Notably, other section 111 standards that have taken the form of a limit on the quantity of pollution during a given period of time. *See* 40 C.F.R. § 60.532(a), (b) (establishing particulate matter standards for new residential wood heaters expressed in grams per hour).
[321] *See* CPP, 80 Fed. Reg. at 64,674.
[322] CPP 80 Fed. Reg. at 64,664.

firm limit on the overall quantity of harmful pollution that sources may emit. In the context of carbon pollution, such a limit directly helps to mitigate the harms of climate change: the climate impacts of carbon pollution from any given source are not determined by the rate per unit of output of that source, but by how much overall carbon pollution that source emits over time. In addition, ten states already use mass-based standards to control carbon pollution from EGUs. Through its proposed definition of "standard of performance,"[323] even EPA acknowledges that mass-based limits are legally permissible under section 111(d). It is arbitrary and unlawful for EPA to prohibit an option that is proven effective in this precise context, when there is no valid statutory or policy reason for doing so.

B. EPA Has Failed to Provide a Lawful Justification for Precluding Averaging and Trading Under Section 111(d) – but if EPA Allows These Mechanisms for Compliance, Averaging and Trading Must Also Inform the BSER.

As many commenters on the proposed CPP observed, averaging and trading are proven mechanisms for assuring cost-effective pollution reduction that are extremely well-suited for the interconnected power sector.[324] EPA's current proposal to prohibit averaging and trading in section 111(d) plans not only runs contrary to the operational realities of the power sector and the long history of averaging and trading in this sector, it has no statutory support and is based on arbitrary rationales.

However, if EPA proceeds to finalize a BSER that is limited to site-constrained measures (such as HRI) and does not require the "degree of emission limitation achievable" considering averaging and trading, it would be unlawful for any state plan to establish a standard that permitted averaging and trading. Likewise, to the extent EPA allows averaging and trading for compliance with standards established under section 111(d), it *must* take them into account when determining the BSER and the stringency of the emission guidelines.

1. <u>The CPP appropriately recognized that averaging and trading are integral to the BSER.</u>

In the CPP, EPA correctly recognized that "it is reasonable for our analysis of the BSER to include an element of source-category wide multi-unit compliance which could be implemented via a state-set standard of performance incorporating emissions trading . . . ."[325] EPA identified a "host of factors" that supported this determination, including:

> (i) the global nature of the air pollutant in question—i.e., CO2; (ii) the transactional nature of the industry; (iii) the interconnected functioning of the industry and the coordination of generation resources at the level of the regional grid; (iv) the extensive experience that states—and EGUs—

[323] *See* 40 C.F.R. § 60.21a(f) (proposed), 83 Fed. Reg. at 44,804 (standard of performance can take the form of "an allowable rate *or limit* of emissions into the atmosphere" (emphasis added). *See also* 83 Fed. Reg. at 44,764 (explaining that the requirement for a rate-based standard applies to "these emission guidelines," thereby acknowledging other forms of standards may be appropriate in some circumstances).
[324] CPP, 80 Fed. Reg. at 64,733 n.380.
[325] *Id.* at 64,733.

> already have with emissions trading; and (v) material in the record demonstrating strong interest on the part of many states and affected EGUs in using emissions trading to help meet their obligations.[326]

EPA further identified a large number of diverse commenters that supported the permissibility of averaging and trading under section 111(d), because of the "well-recognized benefits that trading provides."[327] And EPA detailed the long history of emission trading programs established for the power sector under the Clean Air Act – from the Acid Rain Program to the Cross-State Air Pollution Rule, and state-level trading programs such as the Regional Greenhouse Gas Initiative.[328] Based on this extensive record, EPA concluded that "it is reasonable . . . to determine that states can establish standards of performance that incorporate trading," and that "as a result" the BSER determination itself should "evaluate prospective emission control measures in light of the availability of trading."[329]

2. <u>EPA has failed to provide a lawful, well-reasoned explanation for precluding averaging and trading in section 111(d) plans.</u>

As discussed below, EPA has failed to provide a sound statutory basis for precluding averaging and trading in state plans under section 111(d) and ignoring the availability of such mechanisms in its BSER. Nor has it provided "good reasons" for departing from the conclusions it reached in the CPP or an adequate explanation as to why it is "disregarding facts and circumstances that underlay or were engendered by the prior policy."[330]

EPA has not offered any valid statutory grounds for excluding averaging and trading from the BSER determination and from the design of standards established under section 111(d) state plans. In its discussion of state plans, EPA cryptically references "source-focused language in 111(d)" but fails to cite specific statutory language. In the proposed CPP Repeal—on whose legal analysis the ACE proposal "relies"—EPA stated that, in the 1975 regulations, the Agency interpreted section 111 standards "to be technology-based and source-focused."[331] As we explained in comments on that proposal, EPA's conclusion is incorrect.[332] For one thing, the 1975 Preamble does not utilize the term "source-focused." Its reference to "technology-based" standards is expressly in contrast to "health-based"—it is not presented as a limit on the measures that should be available for either the BSER or compliance.[333]

EPA also fails to address in this context the cross-reference to section 110, upon which the procedure for developing state plans under section 111(d) must be based.[334] Section 110 expressly permits state plans to achieve emission limitations through the use of such flexible

---

[326] *Id.* at 64,733.
[327] *Id.* at 64,733 n.380.
[328] *Id.* at 64,734.
[329] *Id.* at 64,735.
[330] *Fed. Commc'ns Comm'n v. Fox Television Stations*, 556 U.S. 502, 515 (2009).
[331] Proposed Repeal, 82 Fed. Reg. at 48,041.
[332] EDF Repeal Comments at 56-59.
[333] 40 Fed. Reg. 53,340, 53,342.
[334] 42 U.S.C. § 7411(d)(1).

measures as "fees, marketable permits, and auctions of emissions rights."[335] Hence, the statutory evidence strongly suggests that section 111(d) emission guidelines may incorporate such measures into BSER determinations when warranted by the characteristics of the source category and particular pollutant at issue. EPA's regulatory history bears this out: EPA's existing source emission guidelines for large municipal waste combustors, issued in 1995 under the authority of sections 111(d) and 129, authorize sources to use two different flexible mechanisms for compliance: averaging emission rates of several units within a facility, and trading emission credits for nitrogen oxides.[336]

EPA attempts to reconcile its interpretation with the statute by observing that the inclusion of averaging or trading in section 111(d) implementation plans could render superfluous states' authority to consider remaining useful life and other factors when establishing and applying standards of performance. This argument lacks statutory support and defies logic. It is certainly true, as EPA explains in the Clean Power Plan, that the availability of averaging and trading for compliance inherently gives states the flexibility to account for remaining useful life on a source-specific basis without adjusting the overall stringency of a quantitative section 111(d) emission guideline.[337] That indicates that averaging and trading work in harmony with the statute, not that they create a conflict. EPA now seems to suggest that it is *required* to issue emission guidelines that, when converted to standards, some sources are incapable of meeting just so that states have cause to invoke the remaining useful life provision. That interpretation is highly implausible: the statute's recognition that consideration of a source's remaining useful might sometimes be appropriate does not mandate that EPA create such a scenario. Moreover, in adopting a program that allows averaging and trading, states *are* accommodating compliance by sources with short remaining useful lives.[338]

In addition, averaging and trading meet the two criteria that EPA proposes for available compliance options: "(1) They are implemented at the source itself, and (2) they are measurable at the source of emissions using data, emissions monitoring equipment or other methods to demonstrate compliance, such that they can be easily monitored, reported and verified at a unit."[339] EPA premises these criteria on its proposed requirement for a rate-based standard.[340] As explained above, that premise is arbitrary and unlawful, meaning that these criteria have no legal foundation. But here we make the separate point that, even if these criteria apply, averaging and trading satisfy them, so using these criteria to prohibit averaging and trading would be arbitrary.

Averaging and trading "are implemented at the source itself" because, at least in the context of an allowance system, they require that a source procure compliance instruments representing the amount of pollution it emits or credits that may effectively reduce its emissions rate. This does not require the source to take action at any other location. Second, averaging and trading "are measurable at the source of emissions using data, emissions monitoring equipment or other methods to demonstrate compliance, such that they can be easily monitored, reported and

[335] *Id.* § 7410(a)(2)(A).
[336] *See* Richard L. Revesz, Denise A. Grab, & Jack Lienke, *Familiar Territory: A Survey of Legal Precedents for the Clean Power Plan*, 46 ELR 10190, 10191 (2016).
[337] CPP, 80 Fed. Reg. at 64,734-35.
[338] *See* CPP Legal Memorandum at 41.
[339] ACE, 83 Fed. Reg. at 44,765.
[340] *Id.*

verified at a unit."[341] Monitoring compliance with a trading program could be accomplished by measuring the pollution emitted from a smokestack. It is true that that pollution would need to be compared to the number of compliance instruments that a source possesses. But under any pollution control program, the pollution has to be compared to some standard. The only difference is that, in an averaging or trading program, that standard is determined by credits or allowances rather than a regulatory code.

To the extent that EPA would prefer not to consider compliance instruments because—depending on how a state structures its approach—they may represent emission reductions that occurred somewhere other than the source itself, such concerns are misplaced. First, this concern does not apply in the context of a mass-based trading program, in which every allowance represents a ton of emissions from a regulated source and a source's only obligation is to hold allowances commensurate with *its own* emissions. Moreover, such a concern would not be consistent with EPA's proposed approach to biomass co-firing. EPA explains that biomass co-firing satisfies the two criteria because "there are different methods that can be used to monitor or calculate the amount of biogenic CO_2 emissions associated with biomass use at a unit."[342] However, EPA acknowledges that the purported benefits of using biomass

> can typically only be realized if biomass feedstocks are sourced responsibly, which can include ensuring that forest biomass is not sourced from lands converted to non-forest uses. . . . EPA's policy is to treat biogenic CO_2 emissions resulting from the combustion of biomass from managed forests at stationary sources for energy production as carbon neutral.[343]

If stack emissions resulting from the combustion of biomass can be adjusted based on whether the fuel came from a "managed forest," then surely compliance instruments for the purpose of emission trading are not impermissibly removed from the source itself. (We explain below why EPA's proposal regarding biomass is unlawful and arbitrary for other reasons.)

3. <u>EPA's stated "practical concerns" about averaging and trading are unfounded.</u>

EPA also asserts that averaging or trading would introduce "relative complexity" into the state planning process and would increase the difficulty of ensuring robust compliance.[344] This assertion of *relative* complexity, however, neglects to compare the complexity of averaging and trading with other compliance options. As we explain elsewhere in this docket,[345] EPA's proposed approach would create a state planning process rife with uncertainty and confusion. There would be uncertainty about how to assess which HRI technologies are appropriate for each source; uncertainty about quantifying the standard of performance; uncertainty about when sources must demonstrate compliance; uncertainty about which variances may be invoked; uncertainty about the degree of scrutiny with which EPA intends—or is required—to review state plans; and, at several steps along the way, uncertainty as decisions are subject to legal

---

[341] *Id.*
[342] *Id.* at 44,765 n.33.
[343] *Id.* at 44,766.
[344] *Id.* at 44,768.
[345] *See* Joint Environmental Comments on Framework Regulations.

challenge. The CPP approach, in which EPA established definite national performance rates that could be achieved through emissions trading programs similar to those that states and power companies have successfully used for years (such as the Cross-State Air Pollution Rule and the NO_x SIP Call) is far less complex along each of these dimensions.

Moreover, EPA's concerns about the complexity of averaging and trading are unfounded, overblown, and conflict with significant evidence in the record. EPA addresses this problem head-on in the CPP when it determines that trading is "adequately demonstrated" for the purpose of limiting carbon pollution from EGUs. EPA listed several federal and state programs that

> established successful environmental programs for this industry that allow trading of environmental (or similar) attributes, and trading has been widely used by the industry to comply with these programs. Examples include the CAA Title IV Acid Rain Program, the NO_X SIP Call (currently referred to as the NO_X Budget Trading Program), the Clean Air Interstate Rule (CAIR), the Cross-State Air Pollution Rule (CSAPR), the Regional Haze trading programs, the Clean Air Mercury Rule, RGGI, the trading program established by California AB32, and the South Coast Air Quality Management District RECLAIM program.[346]

Reviewing these examples, EPA concludes, "Trading is a regulatory mechanism that works well for this industry. The environmental attributes in the preceding programs (representing emissions of air pollutants) are identical to or similar in nature to the environmental attribute here (CO_2 emissions)."[347]

Against this evidence, EPA now provides two sentences vaguely alleging complexities with trading programs, including concerns about the "difficulty of ensuring robust compliance" and the need for "means of evaluation, monitoring and compliance."[348] The Agency neither cites any source for these allegations, nor provides any example of when such complexities prevented the successful adoption of an emission trading program. Indeed, these unsupported claims fly in the face of the numerous successful trading programs that EPA itself has established – such as CSAPR and the NO_x SIP Call – as well as state-level programs such as RECLAIM that EPA has approved for purposes of attaining the NAAQS. In the context of a rate-based emissions trading program established under the CPP, the Emission Reduction Credits (ERCs) that sources would utilize to demonstrate compliance are functionally equivalent to Renewable Energy Credits that have been in widespread use for decades.[349] EPA has not provided a well-reasoned basis for overturning the Agency's prior, well-supported conclusion.[350]

[346] CPP, 80 Fed. Reg. at 64,735 (citations omitted).
[347] *Id.*
[348] ACE, 83 Fed. Reg. at 44,768.
[349] CPP, 80 Fed. Reg. at 64,806 ("Nearly all states with a mandatory RPS have established RECs as a means of compliance ., . . The development of REC markets to facilitate RPS compliance provides evidence that markets can develop to facilitate compliance with rate-based state plans.").
[350] *See Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (A decision is arbitrary and capricious where the Agency "offered an explanation for its decision that runs counter to the evidence before the agency.").

Numerous comments from the CPP docket also contradict EPA's current claims, as EPA explained in its Response to Comments.[351] For instance, EPA stated:

- "Many commenters noted that cap-and-trade programs are efficient, simple to implement, and easy to enforce."[352]
- "[T]he measurement of CO_2 emissions at sources covered by the cap can be accomplished using existing emissions monitoring equipment and protocols already in place at these sources."[353]
- "Because of the simple and straightforward nature of determining whether the cap is met, Commenters believed budget trading programs obviate the need for EPA or states to conduct a complex analysis to determine whether a state meets its compliance requirements."[354]

EPA referenced several supporting examples in its brief defending the CPP before the D.C. Circuit.[355] And in the CPP Preamble, EPA cites many additional examples of commenters who supported trading as a compliance option.[356] The Regional Greenhouse Gas Initiative ("RGGI") states commented that "every serious proposal to reduce carbon emissions from EGUs . . . has identified allowance trading as the best approach. . . . [M]arket-based programs have been shown to reduce costs to all participants."[357] Attorneys general from RGGI states commented that RGGI's approach is "effective in reducing CO_2 emissions and straightforward to administer."[358] DTE Energy commented that a mass-based program, which it expected would involve trading, would "[p]rovide a simple and cost effective method for achieving the most efficient emission reductions."[359] In joint comments, six utilities stated, "The market-based approach of the 1990 [Clean Air Act] amendments resulted in a substantial reduction in compliance costs."[360]

---

351 EPA's Responses to Public Comments on the EPA's *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* § 5.13, Docket ID No. EPA-HQ-OAR-2013-0602-37106 (Aug. 2015).
352 *Id.* at 278.
353 *Id.* at 278.
354 *Id.* at 278-79.
355 *See, e.g.*, "West Virginia's Principles to Consider in Establishing Carbon Dioxide Emission Guidelines for Existing Power Plants" at 14 (Feb. 20, 2014), Docket ID No. EPA-HQ-OAR-2013-0602-24999. West Virginia noted that "[a] mass-based allowance system would automatically account" for a variety of pollution-reduction measures and called a program modeled on the Acid Rain Program and Clean Air Interstate Rule "one of the most straight-forward approaches." EPA cited these comments and others in Respondent EPA's Final Brief 47-48, *West Virginia v. EPA*, D.C. Cir. No. 15-1363 (filed Apr. 22, 2016).
356 CPP, 80 Fed. Reg. at 64,733 n.380.
357 "RGGI States' Comments on Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 FR 34830" at 8, Docket ID No. EPA-HQ-OAR-2013-0602-22395 (June 18, 2014).
358 Comments of Attorneys General of Eleven States and the District of Columbia and the New York City Corporation Counsel at 3, Docket ID No. EPA-HQ-OAR-2013-0602-25433 (Dec. 1, 2014).
359 "Comments of DTE Energy" at 34, Docket ID No. EPA-HQ-OAR-2013-0602-24061 (Dec. 1, 2014).
360 Calpine Corp. et al., Comments on Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Docket ID No. EPA-HQ-OAR-2013-0602-23167 (Dec. 1, 2014). *See also* The Clean Energy Group, Comments on Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Docket ID No. EPA-HQ-OAR-2017-0355-19852 (Apr. 26, 2018); M.J. Bradley & Associates, Comments on Proposed Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Docket ID No. EPA-HQ-OAR-2017-0355-19928 (Apr. 26, 2018); The Clean Energy Group, Comments on State Guidelines for Greenhouse Gas Emissions from Existing

EPA has pointed to nothing in the record of the CPP or the ACE proposal that contradicts—much less overcomes—the comments and historical evidence indicating that enabling emission trading as a compliance option would reduce the complexity of compliance. In the few areas where CPP commenters raised possible complexities of trading programs—e.g., the interaction of rate- and mass-based trading—EPA addresses the concerns in the final CPP. And even if EPA allows averaging and trading as compliance options, no state would be required to adopt them; EPA's concerns about complexity are not a valid basis for *prohibiting* states from allowing averaging and trading, at the states' discretion.

EPA also states that section 111(d) precludes averaging and trading because it "is directed toward the *improvement* . . . of existing sources . . . not . . . the aggregate emissions of an industrial sector as a whole."[361] EPA provides no support whatsoever for this assertion, and section 111(d) does not utilize any permutation of the word "improve" in the context that EPA suggests. Rather, section 111 is concerned with reducing dangerous air pollution that sources emit.[362] In the case of carbon dioxide—a global pollutant—reductions are equally beneficial wherever they occur. In that context, assigning each source a standard of performance, and allowing the source to demonstrate compliance with the standard through compliance instruments, fully aligns with statutory objectives. It is arbitrary and unlawful for EPA to prohibit that compliance option on this basis.

Lastly, EPA's preclusion of averaging and trading arbitrarily ignores the implications that its legal interpretation of section 111 would have for state leadership and existing state programs. Unlike the CPP, which was deliberately designed to provide states with ample compliance flexibility and to be compatible with existing state climate programs such as RGGI, EPA's rigid proposed approach would limit states to submitting rate-based standards that incorporate no averaging and trading (and as discussed in the next section, can be no more stringent than any standard based on HRI). This would require states with existing and highly effective climate programs (almost all of which are based on mass-based emissions trading programs) to create a new, redundant, and less effective system of rate-based standards solely to comply with EPA's emission guidelines. The CPP carefully avoided this absurd outcome by appropriately recognizing that averaging and trading are permissible means of compliance *and* should inform the determination of the "degree of emission limitation achievable" through the BSER.

4. <u>If EPA does not consider averaging and trading when determining the BSER, it cannot allow these measures for compliance.</u>

Although EPA's rationales for precluding averaging and trading both in its BSER determination and as a compliance measure are not grounded in the statute or the record before the agency, it

---

Electric Utility Generating Units Advance Notice of Proposed Rulemaking, Docket ID No. EPA-HQ-OAR-2017-0545-0349 (Feb. 26, 2018); M.J. Bradley & Associates, Comments on State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units Advance Notice of Proposed Rulemaking, Docket ID No. EPA-HQ-OAR-2017-0545-0350 (Feb. 26, 2018).

[361] ACE, 83 Fed. Reg. at 44,768.

[362] *See Sierra Club v. Costle*, 657 F.2d 298, 325 (D.C. Cir. 1980) (stating that one of the purposes of section 111 is to "maximize the potential for long-term economic growth by reducing emissions as much as practicable," to "increase the amount of industrial growth possible within the limits set by the air quality standards").

would also be unlawful for EPA to allow such measures for compliance if they are not contemplated when determining the stringency of the BSER. To permit averaging and trading for compliance with a BSER that is based solely on site-constrained measures with no averaging and trading would create an unlawful and arbitrary disconnect between the requirements sources face and the pollution reductions sources could achieve.[363] EPA must determine a BSER that bears a rational connection to the compliance measures that EPA expects sources to utilize; otherwise, any standard of performance premised on that BSER may not "reflect" the full "degree of emission limitation achievable" through the application of that BSER, as section 111(a)(1) requires. Congress did not intend asymmetry between standard-setting and compliance, and a rule in that mold would run afoul of section 111.

5. If EPA allows trading and averaging for compliance, it must also consider those measures as a part of the best system of emission reduction evaluation and build them into the stringency of the emission guidelines.

As explained above, trading and averaging offer relatively low-cost means of achieving greater levels of pollution reduction—especially when compared to EPA's proposed BSER and compliance options. Since EPA cannot show that these options are statutorily prohibited for compliance, and they would enable sources to achieve greater pollution reductions at considerably lower cost, EPA has neither a legal nor a policy basis for disallowing them.

Once EPA determines—as it must—that averaging and trading *may* be used for compliance under section 111(d), two important consequences follow. First, it would be logically inconsistent and arbitrary for EPA to recognize that such mechanisms are available for *compliance* while, at the same time, determining that they *cannot* be considered in determining the "best system" and establishing emission guidelines. If a source can lawfully meet a "standard of performance" by obtaining credits representing reduced emissions from other affected sources, there is no logical reason why such transactions—and the emission-reducing activities that those transactions represent—should not be considered when selecting the "best system of emission reduction" and when crafting the emission guideline.

Allowing trading and averaging for compliance, while ruling out such techniques in setting standards, would be like calculating a golfer's handicap assuming that she only has a putter in her bag, while allowing the golfer to play using the full bag of clubs. It would also violate the statutory requirement that standards of performance "reflect" the degree of emission limitation "achievable" through application of the BSER. As EPA stated in its brief defending the CPP in the D.C. Circuit,

> [I]f states can properly craft standards designed to accommodate and encourage the use of generation-shifting as a suitable pollution-control strategy, then EPA can likewise reasonably interpret the phrase "system of emission reduction" to encompass the same

[363] *See Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 397 (D.C. Cir. 1973) ("[A] significant difference between techniques used by the agency in arriving at standards, and requirements presently prescribed for determining compliance with standards, raises serious questions about the validity of the standard.").

> suitable strategy. Section 111 does not dictate the provision of maximum flexibility for the purpose of achieving the most minimal emission limitation.[364]

Second, to the extent EPA's emission guideline encourages or allows states to craft plans that incorporate averaging and trading programs, it would be arbitrary not to consider how such mechanisms would affect the costs of the BSER (even if the BSER consisted of physical modifications adopted at individual sources). This is implicit in the text of section 111(a)(1), which requires that, in selecting the "best system," EPA take into account "the cost of achieving *such reduction*."[365] Where EPA expects that "such reduction" would be achieved primarily through the use of allowance trading or averaging of emission reduction credits rather than implementation of the BSER at each individual source, EPA should take into account the *actual* cost of those "real-world" reduction strategies in determining the BSER. If EPA were to blind itself to those compliance mechanisms in assessing the costs of the BSER, it would arrive at an inaccurate (and almost certainly inflated) assessment of costs and establish an emission limitation that is far weaker than those that could be achieved in practice—contrary to section 111's purpose of achieving "maximum feasible control" of harmful pollution.[366]

Accounting for the cost of achieving emission reductions when setting requirements for stringency is consistent with the D.C. Circuit's recognition in *Sierra Club v. Costle* that "section 111 gives EPA authority when determining the best technological system to weigh cost, energy, and environmental impacts *in the broadest sense at the national and regional levels and over time* as opposed to simply at the plant level in the immediate present."[367] Indeed, in the 1979 NSPS for coal-fired electric generating units at issue in *Sierra Club*, EPA assessed the cost, energy, and environmental impacts of the flue gas desulfurization system it had selected as the BSER by using a national-scale econometric model of the power system. As the court explained, this model took into account changes in new plant construction and utilization that would result from the adoption of the particular standard of performance based on that BSER—to wit, the model took into account how the power system would *actually* respond to the promulgated NSPS.[368] EPA's finding, based on this modeling, that "uniform control is expected to result in greater reliance on old plants and less utilization of new plants than will variable control" was a key factor underlying its selection of the BSER. The court upheld this approach, finding that "to exercise [its] discretion [under section 111] EPA *must* examine the effects of technology on the grand scale in order to decide which level of control is best."[369]

---

[364] Respondent EPA's Final Brief, *West Virginia v. EPA,* D.C. Cir. No. 15-1363 at 48-49 (filed Apr. 22, 2016).
[365] 42 U.S.C. § 7411(a)(1).
[366] State Plans for the Control of Certain Pollutants From Existing Facilities, 40 Fed. Reg. 53,340, 53,342 (Nov. 17, 1975) (Section 111 "requires maximum feasible control of pollutants from new stationary sources . . . . [Section 111(d)] reflected a decision in conference that a similar approach (making allowance for the costs of controlling existing sources) was appropriate for the pollutants to be controlled under section 111(d).").
[367] *Sierra Club,* 657 F.2d at 330 (emphasis added).
[368] *Id.* at 335-36 ("Under the cost minimization model the higher the costs of pollution controls required by the NSPS, the more utilities will delay the retirement of older plants which do not have to comply with the NSPS, and the more utilities will be discouraged from building and operating new plants which must meet the NSPS. Since uniform control is costlier than variable control, uniform control is expected to result in greater reliance on old plants and less utilization of new plants than will variable control, which in turn leads to higher emissions.").
[369] *Id.* at 330 (emphasis added).

C. EPA's Proposed Limitations on the Stringency of State Plans Undermine the Purpose of Section 111 and Violate the Clean Air Act.

Although EPA claims to recognize that "states have the primary role of developing standards of performance consistent with application of the BSER,"[370] the ACE proposal would unlawfully and arbitrarily stifle state leadership and innovation by requiring states to submit standards that are no more stringent than EPA's ineffectual proposed BSER. This approach arbitrarily undermines the role of state innovation and leadership in carrying out climate and clean air protections, and violates the state prerogatives that are guaranteed in section 116 of the Clean Air Act.

In the Proposed Rule, EPA takes direct aim at state leadership to reduce carbon pollution. The Agency objects to implementation measures that "might result in a more stringent standard than could otherwise be derived from application of the BSER."[371] That is, EPA is seeking to prevent states from providing more than the minimal level of public health and environmental protections that ACE would provide. EPA provides no statutory foundation for this concern, other than the requirement that standards of performance must "'reflect . . . the application of the [BSER],' CAA section 111(a)(1)."[372] EPA's truncated snippet of statutory text omits that the statute actually requires standards of performance not to reflect the BSER itself, but to "reflect[] the *degree of emission limitation* achievable through the application of the [BSER]."[373] EPA's position appears to be that a standard of performance that may result in more than the absolute minimum level of pollution reduction does not reflect that "degree of emission limitation." But with complete context, the natural reading of this language is that Congress wished to foreclose *less* protective standards, not that Congress was hostile to greater public protections.

Moreover, EPA's concern runs directly afoul of section 116, which provides that the Clean Air Act shall not "preclude or deny the right of any State or political subdivision thereof to adopt or enforce (1) *any* standard or limitation respecting emissions of air pollutants or (2) *any* requirement respecting control or abatement of air pollution," provided that it is at least as stringent as applicable requirements under sections 111 and 112.[374] Despite the clear statutory directive that states retain authority to adopt "*any* standard," EPA proposes to forbid standards of performance that are more stringent than can be achieved with its feeble proposed BSER because of the mere possibility that they could inhibit sources from emitting the maximum amount of pollution possible under ACE.

EPA attempts to reconcile its proposal with section 116 with the footnote, "While CAA section 116 allows for states to adopt more stringent state laws, and provides that the CAA does not preempt such state laws, it does not provide that those more stringent standards are federalized." This explanation is unavailing. As EPA explains in its discussion of state trading programs in the CPP,

---

[370] ACE, 83 Fed. Reg. at 44,748.
[371] *Id.* at 44,767.
[372] *Id.* at 44,767 (alterations in original).
[373] 42 U.S.C. § 7411(a)(1).
[374] *Id.* § 7416 (emphases added).

> [I]f a state plan complies with all applicable requirements of the CAA (including these guidelines), then the EPA must approve it as satisfactory. This is true even if the emission standards in the state plan are more stringent than the minimum requirements of these guidelines, or the state plan achieves more emission reductions than required by these guidelines. This follows from section 116 of the CAA as interpreted by the U.S. Supreme Court in *Union Elec. Co. v. EPA*, 427 U.S. 246, 263–64 (1976).[375]

By asserting that more stringent pollution limits than those required under ACE should not be "federalized" in standards of performance, EPA seems to imply that states may adopt such limits only through a separate pollution control program under state law. But the *Union Electric Company* Court expressly rejected a reading of section 116 that "would simultaneously require States desiring stricter standards to enact and enforce two sets of emission standards, one federally approved plan and one stricter state plan. We find no basis in the [1970 Clean Air Act] Amendments for visiting such wasteful burdens upon the States."[376] Because Congress in 1970 intended the process of developing implementation plans under section 111(d) to be "similar" to that under section 110,[377] and because section 116 expressly refers to a "standard . . . under section 111," the Supreme Court's reasoning in 1975 applies to section 111(d) rules as well.

Even as the ACE proposal places significant constraints on states' ability to protect their citizens, it arbitrarily opens the door for states that wish to set very weak standards. EPA's proposed BSER is a list of candidate technologies that would modestly improve the heat rate of a coal-fired power plant. In setting standards of performance, EPA proposes that states can decide which of those technologies apply to specific units—or decide none applies at all.[378] Despite this unit-specific approach, EPA has narrowly limited the candidate technologies available. For example, EPA excluded options like carbon capture and sequestration ("CCS") and fuel co-firing in part because they might not be available at some units.[379] As we explain elsewhere, this reasoning is incompatible with EPA's proposed unit-specific approach to standard-setting. In addition, EPA proposes that measures like co-firing and CCS should be available for compliance, claiming that "states and sources are best suited" to make that determination.[380] EPA thereby acknowledges that states are likely to evaluate the availability of such measures to individual units and that some sources may actually implement the measures. But even then, EPA precludes the measures from informing standards of performance, arbitrarily restricting states that wish to establish more stringent standards.

[375] CPP, 80 Fed. Reg. at 64,840.
[376] 427 U.S. at 264; *see also New York v. EPA*, 413 F.3d 3, 42 (D.C. Cir. 2005) ("Section 116 of the Act, 42 U.S.C. § 7416, provides that states and localities may adopt provisions as part of a SIP that deviate from those required for SIPs by EPA, *unless* the state or local provision is 'less stringent' than the EPA provision.").
[377] 42 U.S.C. § 7411(d)(1). *Compare* Pub. L. No. 91-604, § 4(a), 84 Stat. 1684, 1676 ("The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 110 . . . ."), *with id.* § 4(c), 84 Stat. at 1689 ("[I]f an emission standard or limitation is in effect under an applicable implementation plan or under section 111 or 112, such State or political subdivision may not adopt or enforce any emission standard or limitation which is less stringent than the standard or limitation under such plan or section.").
[378] ACE, 83 Fed. Reg. at 44,765.
[379] *Id.* at 44,761-62.
[380] *Id.*

Not satisfied with limiting states to establishing standards of performance based on a narrow and ineffectual list of HRI technologies, EPA also proposes to give states unfettered discretion to apply "variances" in order to weaken the application of the standards to individual EGUs.[381] EPA provides no requirements that would ensure that the resulting standards of performance would achieve the statutory goal of maximum feasible control of emissions. Moreover, EPA's approach would be especially arbitrary in the context of the Proposed Rule, which *already* allows states to set extremely non-protective standards based on unit-specific factors. As with the process for setting standards of performance, EPA makes clear that the invocation of variances can only weaken public protections—not strengthen them—regardless of the measures that may be available at any particular source.

Although the Proposed Rule touts the flexibilities that it provides to states, these flexibilities are unidirectional—giving license to states seeking weaker protections, and restricting states seeking to address climate change in a meaningful way. These one-sided flexibilities are arbitrary and unlawful, and contrary to the protections that Congress intended the Clean Air Act to provide.

D. EPA's Proposed Implementation of the "Remaining Useful Life" Provision Is Arbitrarily Less Protective than BART.

As we explain in the Joint Environmental Comments on the Framework Regulations, the Proposed Rule unlawfully and arbitrarily allows states unfettered discretion to determine standards of performance for existing EGUs without providing any binding, quantitative federal emissions limitations. We also explain that although states are permitted under section 111(d) to take into account "remaining useful life" when applying a standard of performance to "any particular source,"[382] this provision does not displace the states' clear responsibility under section 111(d) to establish "standards of performance" that reflect "the degree of emission limitation achievable" through application of the BSER.[383] EPA's implementing regulations appropriately reflect the view that states should establish standards no less stringent than the quantitative emission limitations contained in EPA emission guidelines, unless physical impossibility or other source-specific limitations render such standards unachievable or unreasonable.[384]

The Proposed Rule's implementation of the "remaining useful life" provision is, however, arbitrary and unlawful for another reason: it fails to acknowledge or consider the fact that EPA has implemented a similar statutory provision under section 169A of the Clean Air Act, and fails to explain why EPA has departed from that approach in the Proposed Rule. As we note above in our discussion of emissions-reducing utilization, section 169A allows states to consider the "remaining useful life" of existing sources when establishing "best available retrofit technology" requirements in state plans.[385] But unlike the Proposed Rule, EPA's long-standing guidance

---

381 *Id.* at 44,773.
382 42 U.S.C. § 7411(d)(1).
383 *Id.* § 7411(a)(1), (d)(1).
384 40 C.F.R. § 60.24(f). Although section 60.24(f)(3) of the implementing regulations also provides that states may cite "other factors" that make application of a less stringent standard "significantly more reasonable," this provision should be read consistently with the other provisions of section 60.24(f) that clearly convey that a less stringent standard is appropriate only in cases of unreasonable cost or "physical impossibility."
385 42 U.S.C. § 7491(g)(2).

implementing that section recognizes that this discretion is not and should not be unlimited. Instead, EPA's guidance for the Regional Haze program provides clear criteria for determining when a source's remaining useful life is sufficiently short to justify altering BART requirements – and requires that a source adopt a federally- or state-enforceable date for its retirement if remaining useful life is used as a justification for a less stringent BART.[386] This guidance fulfills the statutory requirements of section 169A while ensuring that states do not undermine the statute by invoking "remaining useful life" as an all-purpose excuse to avoid the pollution reductions that Congress expected. It would be arbitrary for EPA to finalize the Proposed Rule in its current form without considering this administrative precedent implementing a similar statutory provision,

V. EPA'S PROPOSAL TO DEEM THE BURNING OF FOREST BIOMASS CARBON-NEUTRAL WOULD BE ARBITRARY, CAPRICIOUS, AND UNLAWFUL.

EPA's proposal to deem biomass from managed forests "carbon-neutral" for the purpose of ACE compliance conflicts sharply with the available scientific research. It also violates several principles of administrative and substantive law. EPA provides no support for this approach in the ACE proposal and instead refers to the Agency's Biomass Policy Statement.[387] However, the Biomass Policy Statement indicates that it is not a final action and does not provide a basis for treating biomass as carbon-neutral in any particular context.[388] If EPA intends to treat biomass as carbon-neutral for ACE compliance, it must fully support that decision as part of this rulemaking. Relying upon the Biomass Policy Statement would come nowhere close to meeting that obligation.

A. <u>The Biomass Policy Statement Is Arbitrary and Capricious Because It Is Inconsistent with the Available Scientific Research.</u>

The Proposed Rule is arbitrary and capricious because it is inconsistent with—and largely ignores—the best available science on the climate impacts of forest bioenergy. The Supreme Court has held that, in order to sustain a decision, an Agency "must explain the evidence which is available, and must offer a 'rational connection between the facts found and the choice made.'"[389] Likewise, the D.C. Circuit will reverse an Agency decision premised on a scientific model that lacks a "rational relationship" to "known behavior."[390] EPA's proposed treatment of forest bioenergy fails those basic requirements.

---

[386] 40 C.F.R. Part 51, Appendix Y, section k.1 ("Where the remaining useful life is less than the time period for amortizing costs [of candidate BART controls], you should use this shorter time period in your cost calculations."); section k.2(2) (providing that where the expected retirement date of the facility "affects the BART determination, this date should be assured by a federally- or State-enforceable restriction preventing further operation"); section k.3 (requiring that BART controls be required no later than 5 years after EPA approves the relevant SIP, if the source does not commit to shut down before that date).
[387] ACE, 83 Fed. Reg. at 44,766.
[388] EPA, "EPA's Treatment of Biogenic Carbon Dioxide (CO_2) Emissions from Stationary Sources that Use Forest Biomass for Energy Production" 2 (Apr. 2018), https://www.epa.gov/sites/production/files/2018-04/documents/biomass_policy_statement_2018_04_23.pdf ("Biomass Policy Statement").
[389] *Id.* at 52.
[390] *Chem. Mfrs. Ass'n v. EPA*, 28 F.3d 1259, 1265 (D.C. Cir. 1994).

The Biomass Policy Statement's fatal error is that it assumes *all* forest biomass from managed forests has *zero* climate impact, regardless of the type of feedstock, how the forest is managed, or other relevant factors. This blanket assumption is arbitrary and flies in the face of the scientific literature on biomass carbon accounting. As the attached report prepared by EDF staff explains, the scientific consensus makes clear that the climate impacts of all biofuels, including forest biomass, depend greatly on factors unique to regions and feedstock.[391] As the report explains, "the net greenhouse gas implications of using forest biomass for energy depend on factors such as the current and prior land-use and management practices, the production region, the feedstock type, and the appropriate spatial scale and time horizon for the assessment. Depending on such factors, energy production from forest biomass has the potential to reduce net emissions—as well as to increase net emissions—relative to the use of fossil fuels."[392] If such factors are not appropriately applied and the forests in question are treated with blanket carbon neutrality assumptions, the report makes clear that the total atmospheric impact resulting from forest biomass will go unaccounted for—even where those impacts are as significant or more significant than the fuels that forest biomass replaces.[393]

A recent draft review of EPA's 2014 biomass accounting framework prepared for the Agency's Science Advisory Board likewise concludes that "not all biogenic emissions are carbon neutral nor net additional to the atmosphere, and assuming so is inconsistent with the underlying science."[394] The draft review further recommends that any emissions accounting adjustments for bioenergy be "feedstock-specific" and "region-specific," noting that "estimates of the effects of biomass harvest on carbon stocks depend on the spatial scale of consideration (stand level or landscape level), the initial conditions of carbon stock on the land (e.g., managed forestland, old growth forestland, or agricultural land), the management practices used, and the time horizon over which effects are measured."[395]

Neither the Biomass Policy Statement nor the Proposed Rule give any serious consideration to these factors. Rather, the Biomass Policy Statement contains a brief technical summary of just over two pages, which makes only glancing and selective references to a few of the many considerations relevant to the carbon accounting of biomass.[396] EPA acknowledges the SAB's prior conclusions that it is not "scientifically valid" to assume that all forms of bioenergy are carbon neutral, and that the "net biogenic carbon profile related to the use of biomass feedstocks depends upon . . . feedstock characteristics, production and consumption, and alternative uses." EPA then dismisses these complexities by saying that the scientific analysis "has not to date

---

[391] *See* Ruben Lubowski and Gabriela Leslie, *A review of scientific literature on the climate impacts of forest biomass use* at 1 (Oct. 31, 2018) ("Lubowski & Leslie"). This report has been filed in the docket as an attachment to our comments.
[392] *Id.* at 1.
[393] *Id.* at 3 ("[F]or many forest types and/or regions, the regeneration of forests following harvest can take many decades to centuries, with emissions contributing to dangerous warming effects in the interim . . . For such harvesting types and intensities, the net impact on greenhouse gas emissions from burning the additional biomass harvested will persist for long periods, making their use for bioenergy roughly equivalent to burning fossil fuels for many decades.").
[394] EPA Science Advisory Board, "SAB review of *Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources* (2014)" (Draft Report) at 2 (Aug. 29, 2018).
[395] *Id.* at 10.
[396] Biomass Policy Statement at 2-4.

resulted in a workable, applied approach for consistently assessing the net atmospheric contribution of biogenic CO_2 emissions at stationary sources."[397] And finally, EPA provides a two-paragraph discussion explaining that U.S. forests are currently a net carbon sink, and speculating that increasing demand for U.S. forest biomass could increase forested area.

This is not a well-reasoned basis to assume that all biomass from managed forests is carbon neutral. That accounting for the emissions impacts of biomass is complex, difficult, and subject to uncertainty does not entitle EPA to act "on the basis of a guess about what the facts might be."[398] Nor does it entitle EPA to substitute its desire to support the biomass industry, which is explicitly cited as a basis for the Biomass Policy Statement,[399] for a sound scientific judgment about the climate impacts of forest biomass. Neither section 111 nor any of the authorities EPA points to in the Biomass Policy Statement suggest that EPA may ignore certain types of emissions (or pretend that they have zero impacts on climate) based on extra-statutory policy preferences that are not grounded in a well-reasoned scientific judgment. The Agency has not fully grappled with the uncertainties, nor has it performed a thorough evaluation of the available information and proposed a balanced, scientifically grounded methodology. To the contrary, the Agency has merely noted that pertinent scientific research and analysis is ongoing, acknowledged that the matter is highly complex,[400] and then adopted the most extreme position available. But the complexity of an issue does not relieve the Agency of the requirements of reasoned decisionmaking.

As the attached report demonstrates, none of the rationales advanced by EPA for its assumption of carbon-neutrality are valid. EPA's Biomass Policy Statement cites selectively to a single study suggesting that encouraging use of forest biomass could increase carbon stocks in forests,[401] but does not consider or even acknowledge literature reaching a contrary conclusion. Indeed, our attached report cites several studies finding that "increased forest biomass demand will be partially met by the wood products market instead of increased forest area, such that there is no net gain, or by an increase in harvest frequency and intensity, which may result in decreased carbon stocking relative to less intensive harvesting methods."[402]

The Biomass Policy Statement also suggests that treating forest biomass as carbon-neutral would be consistent with policies in the European Union, California, and the RGGI states. But the statement fails to acknowledge prominent criticisms of this approach, or recent actions by European Union institutions questioning the validity of the carbon-neutrality policy and committing to resolve acknowledged scientific deficiencies in the policy.[403]

---

397 *Id.* at 4.
398 *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 531 (D.C. Cir. 1983).
399 Biomass Policy Statement at 2 ("Use of these biomass feedstocks for energy at stationary sources can provide numerous economic benefits to rural communities, including new jobs and income from forest biomass industry and support of existing tourism and recreation industries in forested areas….Many forest and forest products industry stakeholders view the lack of a clear EPA policy on the treatment of biogenic CO_2 emissions resulting from the combustion of forest biomass for energy at stationary sources as an impediment to the use of biomass from managed forests for bioenergy purposes, thus frustrating the realization of its expected environmental and economic benefits.").
400 *Id.* at 3.
401 *Id.* at 5.
402 Lubowski & Leslie, at 4-5, 11-12.
403 *Id.* at 5.

Moreover, it does not help EPA that the proposed carbon-neutral treatment of forest biomass extends only to "managed forests." As the attached report explains, EPA's proposed definition of managed forests is extraordinarily broad and is not limited to forests that are managed for the specific purpose of conserving carbon stocks. As one example of the deficiencies in EPA's definition, the shifting of a more mature managed forest to a "more frequently harvested system" would qualify as carbon-neutral under the Biomass Policy Statement, even though the effect of this change in management could be to diminish carbon stocks.[404]

The attached report also explains that the consequences of EPA's arbitrary assumption of carbon-neutrality are significant. Depending on feedstock- and region-specific factors, forest biomass that is used for fuel can have severe climate impacts that lasts for decades – impacts that are, in some cases, even greater than the fossil fuels it is replacing.[405] In the context of roundwoods and large trees covered by the Biomass Policy Statement, the report notes that "While certain regions and feedstock types may perform better relative to others, when assessed at an appropriate scale, few biomass feedstocks exhibit carbon neutrality over 100 year timelines, let alone over 10-, 20-, or 30-year timelines that are most relevant for near- and mid- term climate mitigation policy targets."[406]

EPA's proposal to allow the use of biomass for ACE compliance fails to reasonably incorporate the available scientific information, violates statutory obligations, and undermines statutory purposes.

B. <u>Treating Biomass as Carbon-Neutral Is Neither Required Nor Permitted by Statute.</u>

In the Biomass Policy Statement, EPA observes that the Consolidated Appropriations Act, 2018, H.R. 1625, directs EPA, among other agencies, "to establish policies that reflect the carbon-neutrality of forest bioenergy . . . provided the use of forest biomass for energy production does not cause conversion of forests to non-forest use."[407] Elsewhere, EPA states that its Biomass Policy Statement is "in accordance with" the Appropriations Act's language.[408]

EPA's interpretation of the Appropriations Act is unsupported by any analysis and is arbitrary and capricious. The statutory language does not compel EPA to adopt a blanket policy that forest bioenergy used in stationary sources is carbon-neutral. The phrase "reflect the carbon-neutrality of forest bioenergy" is broad and does not dictate a particular outcome. Nor does it divest EPA of authority and responsibility to develop policies based on reasoned decisionmaking. Rather, the statutory language calls on EPA to establish policies that account for and reflect the actual extent to which bioenergy is carbon-neutral. By analogy, if an exchange rate "reflects" the strength of the dollar, it does not mean that the dollar is infinitely strong, only that the actual degree of strength is incorporated into the calculation. EPA arbitrarily misinterpreted the statutory

[404] *Id.* at 4.
[405] *Id.* at 1, 3.
[406] *Id.* at 10.
[407] Biomass Policy Statement at 1; *see also* H.R. 1625 § 431.
[408] Biomass Policy Statement at 2.

language as mandating a particular, scientifically flawed outcome and consequently established a policy that neither satisfies its statutory obligations nor adequately encompasses a reasoned assessment of forest biomass.

Additionally, EPA improperly bound itself to its misinterpretation of a single phrase in the Appropriations Act, while ignoring other important language in the statute. Section 431 of the Appropriations Act specifically states that the biomass policies must be carried out "consistent with [EPA's] mission."[409] Accordingly, EPA has the responsibility to establish policies that are consistent with the pollution reduction objectives of the statutes it implements, including section 111 of the Clean Air Act, and its mission "to protect human health and the environment."[410] But the Biomass Policy Statement would thwart the Clean Air Act by arbitrarily adopting an approach that would result in an inaccurate calculation of pollution resulting from stationary sources.

EPA also failed to fully consider Congress's direction by inadequately ensuring that the policy "does not cause conversion of forests to non-forest use." Appropriations Act § 431. In the Policy Statement, EPA states in a footnote that the forests covered by the policy will not result in conversion, but the Agency does not provide support for this proposition.[411] Rather than analyze the serious concerns that blanket carbon-neutrality will lead to more forest conversion, EPA is satisfied with concluding that its policy "could potentially" have the opposite effect.[412] This conclusion, which is unsupported by any analysis, is insufficient to give effect to the congressional directive.

Even if EPA's interpretation of the Appropriations Act were permissible—which EDF strongly disputes—it could not be upheld as a matter of discretion because the Agency failed to consider other permissible interpretations. When an agency incorrectly believes a particular statutory interpretation is compelled, its interpretation is arbitrary, does not warrant deference, and is subject to reversal.[413] EPA violates this D.C. Circuit precedent to the extent the Biomass Policy Statement is grounded in statutory language that the Agency has misconstrued as a congressional mandate to reach a particular policy outcome. Even if the Agency had acknowledged other possible interpretations of the statute, it did not perform the analysis necessary to sustain a legitimate act of discretion: the Biomass Policy Statement does not indicate that EPA considered alternatives to its statutory interpretation, and it is devoid of any demonstration of the process by which EPA reached its conclusion. Either EPA incorrectly believed it was mandated to adopt the Biomass Policy Statement, or it issued an inadequately supported discretionary decision. Either way, no deference is warranted.

---

[409] H.R. 1625 § 431.

[410] EPA, *Our Mission and What We Do*, https://www.epa.gov/aboutepa/our-mission-and-what-we-do (last visited October 30, 2018).

[411] *See* Biomass Policy Statement at 1 n.1 (defining "managed forest").

[412] *Id.* at 5.

[413] *See, e.g., Prill v. Nat'l Labor Relations Bd.*, 755 F.2d 941, 947 (D.C. Cir. 1985) ("An agency decision cannot be sustained . . . where it is based not on the agency's own judgment but on an erroneous view of the law.").

C. The Biomass Policy Statement Cannot Be Justified by Executive Orders.

The Biomass Policy Statement claims to be consistent with Executive Orders 13,777 and 13,783, but these directives do not compel EPA's approach and cannot supplant the Agency's obligations to adhere to principles of reasoned decisionmaking. While these executive orders generally address regulatory and energy policy, neither order mandates a particular treatment of forest biomass—or even mentions bioenergy at all. EPA fails to cite any specific language in the executive orders to support the claim that the Biomass Policy Statement is "in accordance with" them.

Even if the Executive Orders did provide explicit direction with respect to forest biomass accounting, both executive orders must be implemented "consistent with applicable law."[414] The Executive Orders cited by EPA do not and cannot abrogate the Agency's responsibility to engage in reasoned decisionmaking as required by section 307(d) of the Clean Air Act.[415] Establishing compliance pathways under ACE based on the Biomass Policy Statement or executive orders would mean relying on extra-statutory considerations that are not relevant or permissible for EPA to consider under the Clean Air Act.[416] EPA must guarantee that any policy regarding forest biomass is in line with its statutory authority and obligations.

VI. THE PROPOSAL UNLAWFULLY FAILS TO CONSIDER ENVIRONMENTAL JUSTICE.

The proposal unlawfully neglects to consider environmental justice concerns. EPA is required to consider the impact of its actions on environmental justice communities by a number of statutes, executive orders, and internal policies. Executive Order 12,898 directs federal agencies to identify and address disproportionate adverse health or environmental effects of Agency programs, policies, and activities on communities of color and low-income populations within the United States and its territories. Title VI of the Civil Rights Act of 1964 prohibits discrimination on the basis of race, color, or national origin in all programs or activities receiving federal funding—including both intentional discrimination and actions resulting in discriminatory impacts. The ACE proposal could result in a violation of Title VI if it results in an inequitable distribution of environmental benefits or harms. In order to stop and reverse the advancement of discrimination, EPA must actively center environmental justice and equity in its policies and ensure that the most vulnerable and overburdened communities will benefit from climate and clean air protections.

EPA has previously recognized the importance of these obligations and taken concrete steps to meet them. EPA's EJ 2020 Action Agenda identified air quality issues, specifically fine particulate matter pollution, as a significant national environmental justice challenge prioritized

[414] Exec. Order. 13,777 § 6(b) (Mar. 1, 2017); Exec. Order 13,783 § 8(b) (Mar. 28, 2017).
[415] *See Chrysler Corp. v. Brown*, 441 U.S. 281, 302 (1979) (The exercise of authority by agencies, even when consistent with presidential executive orders, "must be rooted in a grant of such power by the Congress and subject to limitations which that body imposes.").
[416] *See Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) ("Normally, an Agency rule would be arbitrary and capricious if the Agency has relied on factors which Congress has not intended it to consider.…").

for progress.[417] EPA set as a goal: "Achieve air quality that meets the fine particle pollution national ambient air quality standards in all areas of the country, with special emphasis on communities with poor air quality and low-income populations."[418] It further identified climate change as an important cross-cutting issue, recognizing: "Climate change is an environmental justice issue because low-income communities and communities of color are likely to be disproportionately affected by, and be less resilient in absorbing and adapting to, the impacts of climate change."[419] EPA discussed its ongoing climate justice work, including "an emphasis on objectives such as ensuring that underserved communities benefit from energy efficiency and green infrastructure initiatives, training the next generation of young climate justice leaders, and applying EJSCREEN and other Agency efforts and tools that impact communities."[420] It set a goal to advance efforts to mitigate the effects of climate change in vulnerable communities.[421] EPA pledged to "[e]nsure environmental justice is appropriately analyzed, considered and addressed in EPA rules with potential environmental justice concerns, to the extent practicable and supported by law."[422]

EPA's ACE proposal does not advance any of these goals, and indeed reverses progress on these initiatives. First, EPA provides scant analysis or consideration of environmental justice impacts of the proposal. The preamble contains a mere two paragraphs on environmental justice. With no justification or analysis EPA states that the proposed rule "is unlikely to have a proportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples."[423] EPA has no basis to draw such a conclusion when the RIA itself, as discussed in the Joint Environmental Comments on Regulatory Impact Analysis, states that EPA has not yet completed a distributive analysis and will provide so only in a final rule.[424] Moreover, as explained below, EPA does not explain how this conclusion is consistent with its well-documented findings in the CPP that reductions in pollution from power plants (which the Proposed Rule would virtually undo) would have significant beneficial impacts on minority and low-income communities. EPA dubiously states that it "believes that this proposal will achieve CO_2 emission reductions resulting from implementation of these proposed guidelines, as well as ozone and $PM_{2.5}$ emission reductions as a co-benefit."[425] EPA barely acknowledges the drastic lost benefits from the repeal of the CPP and the actual minimal emission reductions anticipated under this rule, which is in fact likely to increase carbon emissions and other air pollutants.

Indeed, this rule is likely to have a disproportionate impact on environmental justice communities. The loss of CO_2 emission reductions disproportionately impacts environmental justice communities. Communities of color and low income communities face increased vulnerability to climate impacts due to numerous issues including their higher likelihood of

[417] EPA, EJ 2020 Action Agenda at 45 (Oct. 2016), https://www.epa.gov/environmentaljustice/environmental-justice-2020-action-agenda.
[418] *Id.*
[419] *Id.* at 11-12.
[420] *Id.* at 12.
[421] *Id.* at 26.
[422] *Id.* at 2.
[423] ACE, 83 Fed. Reg. at 44,797.
[424] ACE RIA at 5-7.
[425] ACE, 83 Fed. Reg. at 44,797.

"living in risk-prone areas. . . , areas with older or poorly maintained infrastructure, or areas with an increased burden of air pollution."[426] These communities can face higher incidences of chronic medical conditions that can be exacerbated by climate impacts.[427] And these communities can face other barriers to preparing for and dealing with climate impacts—such as language barriers, decreased access to health care, and limited transportation.[428] Higher levels of co-pollutants under the ACE proposal as compared to the CPP are also likely to disproportionately impact communities of color and low income communities. These communities are more likely to live in areas with poor air quality[429] and have some of the highest rates of asthma prevalence.[430] A higher percentage of people of color and low-income communities live near power plants compared to the national averages and thus these already overburdened communities will be unduly impacted by the lack of emission reductions in fine particulate matter and other co-pollutants.

EPA must provide an analysis and remedy any disparate impacts that arise from this proposal. This includes addressing impacts from the loss of emission reductions and potential increase in emissions resulting from EPA's choice of BSER and decision not to issue a binding, numerical emission limit to guide state plans. EPA also must analyze, consider, and address the impacts of the proposed changes to the New Source Review ("NSR") program. As discussed in the Joint Environmental Comments on NSR Issues, these changes are also likely to result in significant increases in air pollutants that are damaging to human health for nearby populations.

EPA has the ability to conduct a thorough environmental justice analysis. In the CPP rulemaking, EPA provided a proximity analysis using its EJSCREEN tool which analyzed demographical data for populations living near power plants affected by the rule and found them to be disproportionately minority and low-income.[431] EPA has the ability to conduct air quality modeling using tools such as Environmental Benefits Mapping and Analysis Program ("BenMAP") as well as other Agency resources outlined in EPA's Technical Guidance for Assessing Environmental Justice in Regulatory Analysis.[432]

In the CPP, EPA took steps to take into account environmental justice considerations—EPA must implement similar and greater measures here to ensure environmental justice concerns are addressed. EPA's current proposal does not even provide for basic procedural mechanisms to account for environmental justice. EPA must at minimum require states to meaningfully involve environmental justice communities and consider the equitable distribution of impacts as they develop state plans.

---

[426] Janet L. Gamble et al., *Populations of Concern* at 252, in U.S. Global Change Research Program, *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment* (2016), http://dx.doi.org/10.7930/J0Q81B0T.

[427] *Id.*

[428] *Id.*

[429] Marie Lynn Miranda et al., *Making the Environmental Justice Grade: the Relative Burden of Air Pollution Exposure in the United States*, International Journal of Environmental Research and Public Health, vol. 8,6 (2011): 1755-71, https://www.ncbi.nlm.nih.gov/pmc/articles/PMC3137995/.

[430] LJ Akinbami et al., *Trends in Asthma Prevalence, Health Care Use, and Mortality in the United States, 2001–2010* [NCHS Data Brief], National Center for Health Statistics (2012), https://www.cdc.gov/nchs/data/databriefs/db94.pdf.

[431] CPP, 80 Fed. Reg. at 64,915.

[432] EPA, Technical Guidance for Assessing Environmental Justice in Regulatory Analysis at 38-40 (June 2016).

The Proposal itself also failed to provide for meaningful involvement by environmental justice communities. EPA held only one public hearing on the proposal, in Chicago, which shut out participation by all those unable to travel to that location on that day. There is no evidence that EPA conducted any targeted outreach to environmental justice communities. As described above, EPA has not provided enough transparency on the impacts of this proposal to ensure that their participation would be meaningful. EPA must involve environmental justice communities in this rulemaking process and address their concerns. EPA's technical guidance on environmental justice highlights the importance of providing an analysis of environmental justice concerns in plain language and to allow for early engagement of stakeholders to provide information on unique exposure pathways or end points of concern to improve the environmental justice analysis.[433] In order to achieve meaningful involvement, EPA must not finalize the proposal without providing for an environmental justice analysis that actively engages communities and allows ample time and opportunity for their feedback and review.

VII. THE PROPOSED RULE IS ARBITRARY, CAPRICIOUS, AND UNLAWFUL DUE TO SEVERAL ADDITONAL PROCEDURAL FLAWS.

A. EPA Has Provided Inadequate Opportunities for Public Comment.

Since the comment period opened on August 31, EPA has received a flood of requests from a variety of stakeholders seeking an extension of the comment period as well as additional opportunities for public hearings. These requests have been filed by state attorneys general and city attorneys;[434] state environmental regulators;[435] governors;[436] tribal environmental regulators;[437] the nation's most high-profile associations of state legislators, state utility

---

[433] *Id.* at 9.

[434] *See* Attorneys General of New York et.al., Request for Extension of Comment Period Regarding Proposed Rule to Replace the Clean Power Plan, 83 Fed. Reg. 44,746 (Aug. 31, 2018), (Sept. 11, 2018) (request by Attorneys General of New York, nineteen other states, and the District of Columbia; the City Attorneys of six cities; and the county attorney of Broward County, FL).

[435] *See* Kansas Department of Health and Environment, Comment on EPA Proposed Affordable Clean Energy (ACE) Rule, Docket ID No. EPA-HQ-OAR-2017-0355-22135, (Oct. 1, 2018); New Mexico Environment Department, Request for 90-Day Extension of Comment Period on Proposed "Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating units; Revisions to the Emission Guideline Implementing Regulations; Revisions to New Source Review Program" - Docket ID No. EPA-HQ-OAR-2017-0355, Docket ID No. EPA-HQ-OAR-2017-0355-21901 (Sept. 21, 2018); Minnesota Pollution Control Agency and Minnesota Department of Commerce, Request for Extension of Comment Period for Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program (Docket ID No. EPA—HQ—OAR-2017-0355), Docket ID No. EPA-HQ-OAR-2017-0355-21364, (Sept. 7, 2018).

[436] *See* Connecticut Governor Daniel P. Malloy, Request for Additional Public Hearings to be Scheduled, Docket ID No. EPA-HQ-OAR-2017-0355-22768, (posted to docket Oct. 18, 2018).

[437] *See* National Tribal Air Association, Comment Deadline Extension Request for Docket # EPA-HQ-OAR-2017-0355: Emission Guideline for Greenhouse Gas Emissions From Existing Electric Utility Generating units; Revisions to the Emission Guideline Implementing Regulations; Revisions to New Source Review Program Proposed Rule (Affordable Clean Energy Rule), Docket ID No. EPA-HQ-OAR-2017-0355-21710, (Sept. 5, 2018).

commissioners, and other state officials;[438] members of Congress;[439] environmental justice organizations;[440] public health organizations;[441] and EDF and other public health and environmental organizations.[442]

These requests have pointed out that a 61-day comment period and a sole opportunity for public hearing are manifestly inadequate to allow the public to meaningfully comment on a proposal as complex and consequential as the Proposed Rule. Indeed, the Proposed Rule effectively comprises three major rulemakings in one. In addition to proposing a complete reversal from the CPP that relies on both new technical analyses and new legal interpretations, the Proposed Rule also contains major amendments to EPA's long-standing implementing regulations for section 111(d) and sweeping changes that would severely weaken the New Source Review program for modifications to EGUs. Each of these three initiatives would, standing alone, represent major regulatory undertakings that would warrant an unusually long comment period. By compressing them into one rulemaking with a 61-day comment period, EPA has effectively truncated the public's opportunity to comment.

What is worse, the Proposed Rule rests on a patently deficient technical record that is riddled with gaps—making it even more difficult for the public to understand and respond in an informed way. As we have documented in these comments, EPA rejects a number of alternative systems of emission reduction, such as natural gas co-firing and carbon capture and sequestration, without any analysis of the costs, pollution reduction benefits, or feasibility of those options; has not analyzed the full impacts of the New Source Review modifications it has proposed, and provides no analysis of what the pollution reduction benefits and costs of maintaining the current New Source Review regulations would be; and makes generalized assertions about the impacts of the Clean Power Plan without providing any specific evidence or support to substantiate them. Responding to this deeply technical and multi-faceted rulemaking has necessarily required complex and time-consuming analysis, providing yet more need for additional time to comment.

---

[438] *See* National Conference of State Legislatures, the Environmental Council of the States, National Association of Clean Air Agencies, National Association of State Energy Officials, and the National Association of Regulatory Utility Commissioners, Request for 120-day Comment Period on Proposed Rule "Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program", or ACE Rule, Docket ID No. EPA-HQ-OAR-2017-0355-21870, (Sept. 13, 2018).)

[439] Letter from Sen. Edward J. Markey and 22 other Senators to Acting Administrator Wheeler, EPA (Oct. 9, 2018), *available at* https://www.markey.senate.gov/imo/media/doc/Extend%20ACE%20Public%20Comment%20Period.pdf.

[440] *See* WE ACT for Environmental Justice, Comment period extension request for proposed Affordable Clean Energy Rule – (Docket No. EPA-HQ-OAR-2017-0355), Docket ID No. EPA-HQ-OAR-2017-0355-22770, (Oct. 12, 2018).

[441] *See* American Lung Association et. al., Comment period extension request for proposed rulemaking– Docket No. EPA-HQ-OAR-2017-0355, Docket ID No. EPA-HQ-OAR-2017-0355-21872, (Sept. 18, 2018) (request of American Lung Association and seven other public health organizations).

[442] Request for extension of the comment deadline and public hearings for Proposed Rule: Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program, Docket ID No. EPA-HQ-OAR-2017-0355-21199, (Sept. 6, 2018) (request by EDF and eleven other environmental NGOs).

Despite these deficiencies, EPA has refused to grant any of the multitude of requests for additional time and additional public engagement. It is difficult to overstate the stark contrast between EPA's approach here and the process that was used to develop the CPP itself, in which EPA provided a nearly six-month period for comment; held four public hearings in different regions of the country; and preceded the proposed rule with numerous public listening sessions and stakeholder meetings. With such significant public health and environmental consequences at stake, and major legal and technical questions in play, it would be arbitrary and unlawful for EPA to finalize a rule based on this truncated and inadequate comment period. We urge EPA once again to provide an extended window for public comment, as well as additional opportunities for public hearings so that individuals and communities who were not able to attend the October 1 hearing in Chicago can participate in this rulemaking.

B. EPA Has Violated Executive Order 13,132 on Federalism by Failing to Consult with State and Local Officials as Required.

As the Proposed Rule states, "[u]nder Executive Order 13132, EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs and that is not required by statute unless the federal government provides the funds necessary to pay the direct compliance costs incurred by state and local governments, or EPA consults with state and local officials early in the process of developing the proposed action."[443]

The Proposed Rule acknowledges that this proposal "may have federalism implications" and in particular may "impose substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs."[444] The Proposed Rule further recognizes that the "development of state plans will entail many hours of staff time to develop and coordinate programs for compliance with the proposed rule."[445] As noted elsewhere, the proposal's indeterminate approach, in addition to undermining achievement of pollution reductions, also creates a significant time and staff burden for state agencies. Moreover, states will suffer harmful impacts under the proposed rule because they cannot control emissions from beyond their boundaries, a duty that Congress ascribed to the federal government.[446]

Under E.O. 13,132, the agency must consult with state and local officials "early in the process of developing the proposed regulation."[447] The Proposed Rule does not claim that this plain requirement does not apply here, or provide any justification why compliance with this requirement is not practicable. Yet there is no sign that EPA has engaged in any such consultation, which the executive order clearly provides must occur early on, *before* a proposed rule is issued, as it is being developed. The preamble instead just includes a blanket request for comments, stating that "EPA specifically solicits comment on this proposed action from state and local officials."[448] Given the significant federalism implications that EPA recognizes are at

[443] ACE, 83 Fed. Reg. at 44,796; *see also* Exec. Order 13,132 Section 6(b), 64 Fed. Reg. 43,255 (Aug. 10, 1999).
[444] ACE, 83 Fed. Reg. at 44,796.
[445] *Id.*
[446] *Massachusetts v. EPA*, 549 U.S. 497, 519-20 (2007).
[447] Exec. Order 13,132 Section 6(b)(2)(A).
[448] 83 Fed. Reg. at 44,796.

stake in this rule, this generic and late request is wholly inadequate to meet the consultation requirements laid out in E.O. 13,132.

This failure to conduct required pre-proposal consultation with state and local officials is particularly egregious in light of the deeply harmful impacts at stake: according to EPA's own record, thousands of early deaths and massive pollution increases. Moreover, this omission is exacerbated by EPA's failure to grant (or even respond to) requests for an extension of the comment deadline submitted by numerous subnational officials.[449] This marginalization of state and local input belies the federalism concerns that EPA elsewhere trumpets as a justification for this deeply harmful rule.[450]

This inadequacy is particularly notable in comparison to the extensive pre-proposal consultation EPA carried out during the development of the Clean Power Plan. The Clean Power Plan proposal noted that, in advance of release of the proposed rule, EPA engaged with the "Big Ten" organizations representing elected state and local officials[451]; the proposal also described the "extensive stakeholder outreach" conducted by the agency which "allowed state leaders, including governors, environmental commissioners, energy officers, public utility commissioners, and air directors, opportunities to engage with EPA officials and provide input regarding reducing carbon pollution from power plants."[452]

In light of the failure to follow the deeply relevant requirements under Executive Order 13,132—or even acknowledge this omission—the agency must withdraw the current proposal.[453] Before moving forward, the agency must first meaningfully engage with state and local officials, and only issue any proposed rule after considering feedback and input received.

---

[449] *See supra* § VII.A.

[450] ACE, 83 Fed. Reg. at 44,765 ("In light of the cooperative-federalist structure of section 111(d) and its express language requiring that EPA allow states to take into account source specific factors when establishing standards of performance for existing sources, EPA believes it is appropriate in this proposal to provide considerable flexibility for states to set standards of performance for units and also allow states to have considerable latitude for implementing measures and standards for affected EGUs.").

[451] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule, 79 Fed. Reg. 34,830, 34,947 (June 18, 2014) (listing the Big Ten organizations as (1) National Governors Association; (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States).

[452] *Id.*; *see also id.* at 34,845-47 (detailing pre-proposal stakeholder engagement, including with state and local officials). The preamble of the Clean Power Plan final rule gave an update on this outreach and detailed how the final regulation reflected the specific feedback received. *See* Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule, 80 Fed. Reg. 64,662, 64,937-38 (Oct. 23, 2015).

[453] *See Steenholdt v. FAA*, 314 F.3d 633, 639 (D.C. Cir. 2003) (noting the longstanding principle that federal agencies must "follow their own rules, even gratuitous procedural rules that limit otherwise discretionary actions"); *see also Edison Elec. Inst. v. EPA*, 391 F.3d 1267, 1269 (D.C. Cir. 2004) (an agency must adequately account for any departures from its usual criteria and procedures).

C. EPA Has Failed to Follow Its Own Policy on Consultation and Coordination with Indian Tribes.

EPA's Policy on Consultation and Coordination with Indian Tribes provides that consultation with tribes "should occur early enough to allow tribes the opportunity to provide meaningful input that can be considered prior to EPA deciding whether, how, or when to act on the matter under consideration. As proposals and options are developed, consultation and coordination should be continued, to ensure that the overall range of options and decisions is shared and deliberated by all concerned parties . . . ."[454]

Yet the proposed rule indicates that no consultation with tribes has occurred, instead stating vaguely that "EPA will engage in consultation with tribal officials during the development of this action."[455] Thus the proposed rule concedes that tribal consultation is appropriate here—which it clearly is, given the implications for tribal resources and well-being. Yet it appears the agency has failed to initiate any such consultation during the development of the proposal, at the point when input can be particularly impactful and in contravention of the EPA consultation policy's own stipulation that consultation occur "early enough" and "prior to EPA deciding whether, how, or when to act."[456] Moreover, it appears that EPA has never responded to and functionally denied a request from a relevant tribal organization for an extension of the comment period, exacerbating the failure to consult.[457]

In contrast, the Clean Power Plan proposed rule detailed the extensive consultation with tribes that had already occurred—noting that "[c]onsultation letters were sent to 584 tribal leaders" and describing a webinar, a meeting with tribal representatives, teleconferences with representatives of the National Tribal Air Association, and listening sessions with tribes and state agencies as well as a separate session just with tribes.[458]

Again, in light of the failure to consult with tribes in advance of issuing this proposal—or even provide any explanation for this omission—the agency must withdraw the current proposal.[459] Before moving forward, the agency must first consult with tribes, and only issue any proposal after considering feedback and input received.

[454] EPA, EPA Policy on Consultation and Coordination with Indian Tribes at 7 (May 4, 2011), https://www.epa.gov/sites/production/files/2013-08/documents/cons-and-coord-with-indian-tribes-policy.pdf.
[455] ACE, 83 Fed. Reg. at 44,797.
[456] EPA Policy on Consultation and Coordination with Indian Tribes at 7.
[457] *See* National Tribal Air Association, Comment Deadline Extension Request for Docket # EPA-HQ-OAR-2017-0355: Emission Guideline for Greenhouse Gas Emissions From Existing Electric Utility Generating units; Revisions to the Emission Guideline Implementing Regulations; Revisions to New Source Review Program Proposed Rule (Affordable Clean Energy Rule), Docket ID No. EPA-HQ-OAR-2017-0355-21710, (Sept. 5, 2018).
[458] 79 Fed. Reg. at 34,948; *see also id.* at 34,845-57 (further detailing consultation and outreach efforts, including pre-proposal); 80 Fed. Reg. at 64,939 (same).
[459] *See Steenholdt v. FAA*, 314 F.3d 633, 639 (D.C. Cir. 2003) (noting the longstanding principle that federal agencies must "follow their own rules, even gratuitous procedural rules that limit otherwise discretionary actions"); *see also Edison Elec. Inst. v. EPA*, 391 F.3d 1267, 1269 (D.C. Cir. 2004) (an agency must adequately account for any departures from its usual criteria and procedures).

D. <u>The ACE Rulemaking Is Irredeemably Tainted by Former Administrator Pruitt's Involvement in the Proposed Repeal of the CPP, the Analysis of Which Has Been Incorporated into the Rulemaking Here.</u>

As EDF and other organizations as well as a coalition of states demonstrated in our respective comments submitted in April 2018 in opposition to the proposed repeal of the CPP, former Administrator Pruitt should have been barred from participating in the repeal rulemaking as a result of his numerous statements reflecting an unalterably closed and improperly biased mind on matters relating to the Clean Power Plan.[460]

Although former Administrator Pruitt has resigned, the Repeal Proposal that was developed and issued during his time as administrator remains operative, and, in fact, the ACE Proposal relies heavily on the Repeal Proposal for its basic statutory analysis and its explanation of why EPA now regards the CPP as beyond this agency's statutory authority.[461]

For all the reasons stated in our April 2018 filing, the proposal was rendered unlawful by Administrator Pruitt's participation and must be withdrawn. For EPA to finalize any rule that relies in whole or in part on the Repeal Proposal would be unlawful.

---

[460] *See* Environmental Defense Fund et al., Comments on EPA Administrator Scott Pruitt's Improper Prejudgment of Outcome of Proposed Repeal of Clean Power Plan, Docket ID No. EPA-HQ-OAR-2017-0355-17195, (Jan. 29, 2018); California, Delaware, Hawaii, Illinois, Maine, Maryland, New Mexico, New York, Oregon, Vermont, and Washington, the Commonwealth of Massachusetts, the District of Columbia, the County of Broward (Florida), and the Cities of Boulder (Colorado), Chicago (Illinois), New York (New York), Philadelphia (Pennsylvania), and South Miami (Florida), Comments on Administrator Scott Pruitt's Improper Prejudgment of Outcome of Proposed Repeal of Clean Power Plan, Docket ID No. EPA-HQ-OAR-2017-0355-7861, (Jan. 9, 2018).

[461] *See, e.g.*, 83 Fed. Reg. at 44,746 (noting that, "consistent with the interpretation described in the proposed repeal of the CPP, the Agency is proposing to determine that heat rate improvement (HRI) measures are the best system of emission reduction" for coal-fired power plants); *id.* at 44,748 ("This proposal relies in part on the legal analysis presented in the CPP repeal."); *id.* at 44,752 ("As explained in the proposed repeal, . . . the Agency proposes to return to a reading of section 111(a)(1) (and its constituent term, 'best system of emission reduction') as being limited to emission reduction measures that can be applied to or at an individual stationary source.").

Addendum: Emissions-Reducing Utilization Calculation Methodology

This addendum informs section I.A.3 of these comments and describes the approach used to determine mass-based emission limitations for fossil-fuel-fired EGUs based on a system of emissions-reducing utilization. Note that not all calculations are used in each policy case.

Step 1: Compile baseline data.

1. Baseline year is 2016.
2. Compile unit-level data for generation and emissions in the baseline year.
3. Make baseline adjustments where appropriate: treat units that are under the late stages of construction and units that began operating in 2016 as covered sources with baseline generation at 55% capacity factor. Leave retiring units in the baseline without adjustment.
4. Separate units into subcategories of Fossil Steam ("FS") and Natural Gas Combined Cycle ("NGCC"). FS includes both Coal Steam and O/G Steam units.
5. Aggregate generation and emissions to state level, separated within a state if the state is in more than one region (each interconnection is a region).

➢ This calculates:
   - State Baseline FS Generation Within Region
   - State Baseline FS Emissions Within Region
   - State Baseline NGCC Generation Within Region
   - State Baseline NGCC Emissions Within Region

Step 2: Aggregate baseline data to regional level.

1. Sum state-level data to regional level to derive regional baseline totals for each subcategory for both regional generation and regional emissions.

➢ This calculates:
   - Regional Baseline FS Generation
   - Regional Baseline FS Emissions
   - Regional Baseline NGCC Generation
   - Regional Baseline NGCC Emissions

Step 3: Calculate regional emission rates.

1. Divide regional baseline emissions by regional baseline generation to get regional emission rates for each subcategory.

➢ This calculates:
   - Regional FS Emission Rate
   - Regional NGCC Emission Rate

Step 4: Calculate regional FS generation and regional NGCC generation after adjusting utilization based on available Renewable Energy ("RE").

1. Calculate incremental RE generation in each region based on average annual capacity increase for each technology (utility-scale solar photovoltaics, concentrated solar power, distributed solar photovoltaics, onshore wind, geothermal, and conventional

hydroelectricity) from 2012 to 2017 and NREL 2017 Annual Technology Baseline representative capacity factors.[462]

2. Estimate replacement of generation from each subcategory on a pro-rata basis where incremental RE generation replaces FS or NGCC generation based on the share of baseline generation each subcategory represents in the region.
3. If incremental RE generation would completely replace either subcategory, any remaining incremental RE generation is used to replace generation from the other subcategory.

➢ This calculates:
   - Regional Post-RE FS Generation
   - Regional Post-RE NGCC Generation

Step 5: Calculate regional FS generation and NGCC generation after adjusting utilization of FS generation based on available NGCC generation.

1. State NGCC fleet summer capacity in a region is multiplied by the number of hours in a year (8,784) and then by 75 percent to get each state's total potential NGCC generation at 75 percent capacity factor.

➢ This calculates:
   - State's Regional NGCC Potential Generation

2. Combine each state's Regional NGCC Potential Generation within a region into regional totals.

➢ This calculates:
   - Regional NGCC Potential Generation

3. Subtract Regional Post-RE Utilization NGCC Generation from Regional NGCC Potential Generation.

➢ This calculates:
   - Regional Available NGCC Generation

4. Subtract the Regional Available NGCC Generation from Regional Post-RE Utilization FS Generation, stopping when Regional Post-RE Utilization FS Generation equals zero or all Regional Available NGCC Generation is used up. A 6 percent increase in NGCC generation per year is allowed until Regional Available NGCC Generation is reached.[463]

➢ This calculates:
   - Regional Post-RE + NGCC Utilization FS Generation

5. Add all used Regional Available NGCC Generation to the Regional Post-RE Utilization NGCC Generation.

➢ This calculates:
   - Regional Post-RE + NGCC Utilization NGCC Generation

Step 6: Determine regional mass-based limits.

1. Multiply Regional Post-RE + NGCC Utilization FS Generation by the Regional FS Emission Rate from Step 3 to get the region's total allowed FS emissions.

➢ This calculates:

[462] This is a conservative estimate of incremental renewable energy potential and actual renewable energy deployment may be closer to historical maximum deployment.
[463] A 6 percent increase is based on the average annual increase in natural gas generation from 1990 through 2016. This may be a conservative estimate given that natural gas generation increased by 22% in 2012 alone.

- Regional FS Emissions Limit

2. Multiply Regional Post-RE + NGCC Utilization NGCC Generation by the Regional NGCC Emission Rate from Step 3 to get the region's allowed NGCC emissions.

➢ This calculates:
   - Regional NGCC Emissions Limit

Step 7: Determine state mass-goals.

1. Distribute Regional FS Emissions Limit proportionally to states based on each state's share of regional FS generation (State Baseline FS Generation Within Region divided by Regional Baseline FS Generation[464]).
2. If a state falls within more than one region, combine the state's different regional FS emissions into the overall state FS emissions limit.

➢ This calculates:
   - State FS Emissions Limit

3. Distribute Regional NGCC Emissions Limit proportionally to states based on each state's share of the Regional NGCC Potential Generation (State's Regional NGCC Potential Generation divided by Regional NGCC Potential Generation[465]). Note: using the potential generation rather than the baseline NGCC generation captures the increased generation required of NGCC units to reduce FS utilization in Step 5.
4. If a state falls within more than one region, combine its regional NGCC emissions into the overall state NGCC emissions limit.

➢ This calculates:
   - State NGCC Emissions Limit

5. Add State FS Emissions Limit to State NGCC Emissions Limit[466]

➢ This calculates:
   - State Total Emissions Limit

Additional calculations for individual unit caps:

Step 8: Determine emission limitations for individual units.

1. Subtract State FS Emissions Limit from total State Baseline FS Emissions (adding separate regional emissions if state falls within more than one region).

➢ This calculates:
   - State FS Emission Reductions

2. Divide State FS Emission Reductions by State Baseline FS Emissions (adding separate regional emissions if state falls within more than one region).

➢ This calculates:
   - State FS Percentage Emission Reductions

3. Multiply State FS Percentage Emission Reductions by each FS unit's actual emissions in the baseline year.

➢ This calculates:
   - FS Unit Emissions Reduction

---

[464] This represents the state's expected FS generation divided by the region's expected FS generation.
[465] This represents the state's expected NGCC generation divided by the region's expected NGCC generation.
[466] Used in scenarios with combined state caps.

4. Subtract FS Unit Emissions Reduction from the unit's baseline emissions.
➢ This calculates:
    - FS Unit Emissions Limit
5. Subtract total State Baseline NGCC Emissions from State NGCC Emissions Limit (adding separate regional emissions if state falls within more than one region).
➢ This calculates:
    - State NGCC Emission Change
6. Divide State NGCC Emission Change by State Baseline NGCC Emissions (adding separate regional emissions if state falls within more than one region).
➢ This calculates:
    - State NGCC Percentage Emission Change
7. Multiply State NGCC Percentage Emission Change by each NGCC unit's baseline emissions.
➢ This calculates:
    - NGCC Unit Emissions Change
8. Add NGCC Unit Emissions Change to the unit's baseline emissions. If this step results in higher emissions from the unit, ensure that the unit does not exceed 75% capacity factor or its historical capacity factor, whichever is higher (i.e., maximum assumed feasible utilization). If it does, reapportion excess emissions increases to other NGCC units within the state until all emissions increases are assigned or all units are running at maximum assumed feasible capacity.
➢ This calculates:
    - NGCC Unit Emissions Limit