UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

	)	
New Source Performance	)	
Standards for Greenhouse Gas	)	
Emissions From New, Modified,	)	
and Reconstructed Fossil Fuel-	)	**Docket No. EPA–HQ–OAR–2023–0072**
Fired Electric Generating Units;	)	
Emission Guidelines for	)	*Via Regulations.gov*
Greenhouse Gas Emissions From	)	*August 8, 2023*
Existing Fossil Fuel-Fired	)	
Electric Generating Units; and	)	
Repeal of the Affordable Clean	)	
Energy Rule	)	

Comments of Sierra Club, Earthjustice, Conservation Law Foundation, and Appalachian Voices

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I. INTRODUCTION.

Sierra Club, Earthjustice, Conservation Law Foundation, and Appalachian Voices appreciate this opportunity to provide comments on EPA's proposed rule entitled *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 88 Fed. Reg. 33,240 (May 23, 2023), known in brief as the Carbon Pollution Standards or the Proposed Rule.

At the outset of these comments, it is critical to acknowledge the alarming state of global climate change as of mid-2023 and the dire future we face if we do not take the steps necessary to avoid its worst impacts. The Canadian wildfires and worldwide record temperatures of the past few months underscore the fact that catastrophic climate change is no longer a mere possibility, but is now an outright certainty without major policy interventions to eliminate greenhouse gas emissions. The Intergovernmental Panel on Climate Change's (IPCC) most recent Assessment Report warns that "[t]he cumulative scientific evidence is unequivocal: Climate change is a threat to human well-being and planetary health. Any further delay in concerted anticipatory global action on adaptation and mitigation will miss a brief and rapidly closing window of opportunity to secure a livable and sustainable future for all."[1] And the window is brief indeed: the Mercator Research Institute on Global Commons and Climate Change calculates that, at currently global GHG emission rates, the world has merely five years and 11 months before it expends its remaining carbon budget of approximately 250 billion metric tons of CO_2 for staying within the critical threshold of 1.5°C of warming.[2] Above this threshold, many of the severest impacts of climate change will be irreversible.

Any regulation meant to reduce CO_2 emissions from fossil fuel-fired power plants cannot ignore the fast-approaching climate tipping point, a reality that mandates a swift phase-out of *all* fossil fuel-fired electricity generation. EIA reports that fossil fuel-fired EGUs emitted 1,528 million metric tons of CO_2 in 2021.[3] This amounts to approximately one quarter of U.S. GHG emissions for that year[4] and more than the net emissions of every individual country on Earth apart from China, India, Russia, and

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[1] IPCC, *Climate Change 2022: Impacts, Adaptation and Vulnerability-- Working Group II Contribution to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change: Summary for Policymakers*, 35 (2022), https://www.ipcc.ch/report/ar6/wg2/downloads/report/IPCC_AR6_WGII_SummaryForPolicymakers.pdf.

[2] Mercator Research Institute on Global Commons and Climate Change, *Remaining Carbon Budget: That's How Fast the Clock is Ticking*, https://www.mcc-berlin.net/en/research/co2-budget.html (last visited Aug. 1, 2023).

[3] EIA, *Monthly Energy Review: July 2023*, Table 11.6 (July 26, 2023), https://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf.

[4] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021*, Table 2-1 (Apr. 15, 2023), https://www.epa.gov/system/files/documents/2023-04/US-GHG-Inventory-2023-Chapter-2-Trends.pdf. This figure does not include positive and negative emissions from emissions and sinks from removals from land use, land-use change, and forestry.

the United States itself.[5] According to the federal Interagency Working Group's central estimate of $52/metric ton for the social cost of carbon in 2021—a highly conservative value—this amounts to $79.5 billion in climate damages for that year alone.[6]

Despite the oversized contribution of fossil fuel-fired power plants to the climate crisis, utilities and independent power operators are forging ahead with construction of new gas-fired combustion turbines and are poised to considerably expand their numbers in the coming years. EIA projects an addition of approximately 87,000 MW of combustion turbine generating capacity by 2030 (70,000 MW of additional simple cycle capacity and 17,000 MW of additional combined cycle capacity).[7] By 2035—the year that the Biden Administration has targeted for achieving a carbon-free electric sector—EIA's projections show this figure expanding to 120,000 MW of additional capacity (98,000 MW of simple cycle capacity and 22,000 MW of combined cycle capacity).[8]

This growth trajectory could lock in a catastrophic quantity of CO_2 emissions, making it impossible for the U.S. to meet its international commitment to reduce its GHG emissions 50–52 percent by 2030, relative to 2005 levels.[9] To achieve even the lower end of that range, the U.S. will need to cut its annual net GHG emissions by a daunting 2.2 billion metric tons by 2030.[10] While EIA projects that electric sector gas consumption will fall by approximately 35 to 45 percent over the next three decades,[11] this is simply not enough to meet the emission reductions needed to satisfy our global climate obligations.

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[5] This figure reflects country-by-country emissions data from 2020 derived from the WRI/CAIT data set. *See* World Resources Institute, *Climate Watch: Data Explorer*, https://www.climatewatchdata.org/ghg-emissions?end_year=2020&start_year=1990 (last visited Aug. 1, 2023).

[6] Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990*, Table 1 (Feb. 2021), https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

[7] EIA, *Annual Energy Outlook 2023*, Table 9: Electric Generating Capacity (AEO2023 reference case) (March 16, 2023), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2023&cases=ref2023&sourcekey=0.

[8] EIA, *supra* n. 3.

[9] United Nations Framework Convention on Climate Change, *Nationally Determined Contribution for The United States of America- Reducing Greenhouse Gases in the United States: A 2030 Emissions Target*, https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/United%20States%20of%20America%20First/Unite d%20States%20NDC%20April%2021%202021%20Final.pdf (last visited Aug. 1 2023).

[10] A 50 percent reduction of 2005 U.S. GHG emissions, which EPA's GHG Inventory lists at 6,696 MMT, would amount to 3,348 MMT of avoided emissions. This figure is 2,237 MMT higher than net total U.S. emissions of 5,586 MMT for 2021, the most recent year listed in the Inventory.

[11] EIA, *supra* n. 3, at Table 2: Energy Consumption by Sector and Source, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=2-AEO2023&region=1-0&cases=ref2023&start=2021&end=2050&f=A&linechart=ref2023-d020623a.113-2-AEO2023.1-0&map=ref2023-d020623a.4-2-AEO2023.1-0&ctype=linechart&sourcekey=0.

Furthermore, decarbonizing the electric sector is critical not just for reducing its own emissions, but for facilitating clean transitions in other sectors. In 2021, fossil fuel combustion in the transportation, residential, and commercial sectors emitted nearly 2,300 MMT of CO_2, over 36 percent of the nation's net GHG emissions for that year.[12] By shifting away from gasoline-powered automobiles to electric vehicles, and by adopting heat pump technology and induction stoves for homes and commercial buildings, we can achieve dramatic cuts in GHG emissions from those sectors. The size of emissions reductions benefits of electrifying vehicles and buildings depends on the makeup of the electric grid itself. An electric car that is charged by power generated from a coal or gas plant will produce no tailpipe emissions but substantial upstream emissions. If that same vehicle is charged with power generated from a wind or solar facility, its upstream emissions will be zero. The same is true for electric heat pumps or induction stoves installed in homes that obviate the need for gas, fuel oil, propane, or kerosene for home heating and cooking purposes. Thus, even while the electric sector itself is currently responsible for approximately one-quarter of all U.S. GHG emissions, the sizable majority of all U.S. emissions can only be avoided if we decarbonize the electric grid.

The data overwhelmingly point to one conclusion: the U.S. cannot continue burning fossil fuels for electricity if it hopes to have any chance of avoiding runaway climate change. Joint Environmental Commenters thus support the orderly and expeditious retirement of existing fossil fuel-fired EGUs and strenuously oppose all new fossil fuel-fired generation capacity. To the extent that fossil plants continue to operate and that any new ones are built, they must, as a matter of law, be subject to the most stringent emission standards that are achievable. In this regard, Joint Environmental Commenters support EPA's proposed Carbon Pollution Standards and offer these comments both to endorse certain aspects of the proposed rule that we believe are sound and highlight certain flaws or shortcomings that we believe EPA should rectify.

While we endorse a rapid transition away from fossil fuels and toward renewable energy like wind and solar facilities, we recognize that the Carbon Pollution Standards must reflect a "best system of emission reduction" designation that allows sources to run more cleanly, not one that directly requires them to shift generation to renewable energy. That is the crux of the Supreme Court's holding in *West Virginia v. EPA*, 142 S.Ct. 2587 (2023): although EPA's technology-based standards may "incidental[ly]" cause fossil units to reduce their market share, *id.* at 2613 n.4, or persuade utilities to replace those units with more economically viable renewable resources, the agency may not *directly* mandate that sources shift generation toward wind and solar facilities or otherwise retire under section 111 of the Clean Air Act.

EPA's Proposed Rule fully complies with *West Virginia*'s directive: its "best system" measures are based entirely on technologies that allow sources to reduce their stack emissions when they operate. Moreover, it grants sources multiple compliance pathways; no source will be obligated to install any particular technology, but instead will be able to choose from a set of options that take into account different units' time horizons and operational characteristics. In emphasizing the need for a rapid transition away from fossil generation and toward renewable resources, we in no way suggest that EPA's rule should contravene *West Virginia.* On the contrary, precisely *because West Virginia* prohibits EPA from incorporating grid-level generation shifting into its "best system," it is all the

[12] EPA, *supra* n. 4.

more critical that the agency maximize the emission reduction opportunities that *are* lawfully available to it under section 111 in light of the urgent state of the climate crisis.

The comments that follow are focused on exactly that: identifying ways in which the draft regulations could achieve greater emission reductions within the established legal confines of section 111 and could otherwise be strengthened, including by addressing distributional inequities and ensuring meaningful community engagement that impacts outcomes. In addition, our comments highlight, and provide additional legal or technical justification, for certain key aspects of the proposed regulations that we support. Below, we provide a brief summary of the discussion that follows.

Section II addresses some of the key legal principles underscoring section 111(b)'s new source performance standards and section 111(d)'s emission guidelines for existing sources. In **Section III**, we analyze EPA's proposed standards of performance for new combustion turbines and in **Section IV**, its proposed emission guidelines for existing fossil steam units and combustion turbines. **Section V** explains why EPA must formulate its standards and guidelines in terms of net generation output, not gross output. **Section VI** advises EPA and other relevant federal agencies to close regulatory gaps for, and ensure the safety of, CO_2 pipelines and sequestration sites. **Section VII** addresses issues pertaining to hydrogen, and S**ection VIII** discusses monitoring, reporting, and compliance. **Section IX** urges the agency to ensure that all aspects of the rule advance section 111's technology-forcing mandate. In **Section X**, we discuss issues regarding remaining useful life and other factors (RULOF). In **Section XI**, we urge EPA not to permit averaging and trading in state plans, and to establish strict limitations if it if it does allow those options. Finally, in **Section XII**, we raise important considerations regarding affected communities and other stakeholders.

II. EPA MUST ISSUE PERFORMANCE STANDARDS AND EMISSION GUIDELINES THAT REDUCE POWER PLANT CO_2 POLLUTION TO THE MAXIMUM EXTENT THAT IS "ACHIEVABLE," "ADEQUATELY DEMONSTRATED," AND "NOT EXORBITANTLY COSTLY."

While the general legal requirements of section 111 of the Clean Air Act are well known, we consider it valuable to briefly highlight a handful of critical legal concepts that should guide EPA's rulemaking. First, the regulations at issue are mandatory, not discretionary. Under the Clean Air Act, EPA must review and, if appropriate, revise its new source performance standards for a regulated source category at least every eight years. 42 U.S.C. § 7411(b)(1)(B). The agency promulgated CO_2 performance standards for new fossil fuel-fired EGUs on October 23, 2015, 80 Fed. Reg. 64,510 (Oct. 23, 2015); it must, therefore review and, if necessary (and it is indeed necessary), update those standards by October 23, 2023. Furthermore, section 111(d) requires EPA to establish emission guidelines covering "any existing source for any air pollutant . . . to which a standard of performance under this section would apply if such existing source were a new source." 42 U.S.C. § 7411(d)(1). Thus, since October 23, 2015, EPA has had a legal obligation to issue CO_2 emission guidelines for existing fossil fuel-fired power plants.

Nor was the initial 2015 rulemaking discretionary. EPA listed fossil steam EGUs as a source category that "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare" in 1971, 42 U.S.C. § 7411(b), and listed stationary combustion turbines in 1977. 36 Fed. Reg. 5,931 (March 31, 1971); 42 Fed. Reg. 53,657 (Oct. 3, 1977). These listings alone require the agency to regulate air pollution from those power plants under section 111. In *Massachusetts v. EPA*, the Supreme Court held that greenhouse gases—including CO_2—"fit well within the Clean Air Act's capacious definition of an 'air pollutant'" and that EPA must regulate such emissions if it determined that they endanger public health and welfare. 549 U.S. 497, 532 (2007).

Two years later, the agency indeed determined, based on "a large body of robust and compelling scientific evidence," 82 Fed. Reg. at 64,682, that anthropogenic greenhouse gas emissions are the primary driver of climate change and thus seriously endanger public health and welfare. 74 Fed. Reg. 66,496 (Dec. 15, 2009). The D.C. Circuit upheld the Endangerment Finding in its entirety against an industry challenge, and the Supreme Court refused to review that holding. *Coal. for Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 116-25 (D.C. Cir. 2012), *rev'd in part on other grounds sub nom. Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427 (2014); *see also Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 418, 187 L. Ed. 2d 278 (2013) (granting certiorari only on a narrow issue that did not encompass EPA's Endangerment Finding). Furthermore, in the Inflation Reduction Act of 2022 (IRA), Congress included multiple amendments to the Clean Air Act explicitly defining greenhouse gases as "air pollutants" within the meaning of the statute. Pub. L. No. 117–169 (2022), 75 Stat. 1818, §§ 60101–60108, 60111–60114, 60116, 60201, 60503, 60506. The IRA also allocated $18,000,000 to EPA "to ensure that reductions in greenhouse gas emissions [from electricity generation] are achieved through use of the existing authorities of this chapter." *Id*. § 60107 (codified at 42 U.S.C. 7435(a)(6)).

As the agency notes in the preamble, the evidence for the Endangerment Finding has only grown more robust in recent years, with multiple comprehensive reports documenting the devastating impacts that climate change is now having on our planet and concluding that these impacts will grow worse—much worse—without deep and immediate cuts to global greenhouse gas emissions. 88 Fed. Reg. at 33,249–52. Indeed, the danger of the climate crisis and the toll it is already taking on our world is now so overwhelmingly clear as to be self-evident. We write these words in August 2023, having just experienced the hottest month in recorded human history.[13] At this point, we consider the danger of CO_2 emissions to human health and welfare to be an incontrovertible fact, of which courts should simply take judicial notice.

The agency cannot issue regulations that achieve merely nominal or marginal emission reductions from this sector; it must cut power plant CO_2 pollution as much as practicable within the confines of the law. In *Sierra Club v. Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981), the court held that "we can think of no sensible interpretation of the statutory words 'best technological system'[14] which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the

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[13] Ian Livingston, *These places baked the most during Earth's hottest month on record,* WASH. POST, Aug. 2, 2023, https://www.washingtonpost.com/weather/2023/08/02/july-hottest-month-global-temperatures/.

[14] In 1977, Congress amended section 111 to require new source standards reflecting "the best technological system of continuous emission reduction" and existing source standards reflecting the "best system of continuous emission reduction." Clean Air Act Amendments of 1977, Pub. L. No. 95-95, § 109(c)(1)(A), 91 Stat. 685, 699-700. In 1990, Congress restored the original "best system of emission reduction" for both new and existing source standards. Clean Air Act Amendments of 1990, Pub. L. No. 101-549, § 403(a), 104 Stat. 2399, 2631.

optimal standard for controlling . . . emissions." The court rejected an argument that "'EPA may not consider total air emissions in deciding on a proper NSPS,'" asserting that "this position [is] untenable given that one of the agreed upon legislative purposes . . . *requires* that the standards must maximize the potential for long term economic growth 'by reducing emissions *as much as practicable*.'" *Id.* (emphasis added); *see also* 42 U.S.C. § 7401(b) (the Clean Air Act's fundamental purpose is "to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population."[15]); Summary of the Provisions of Conference Agreement on Clean Air Act Amendments of 1970, 116 Cong. Rec. 42,384 (Dec. 18, 1970) (sources regulated under section 111 "must be controlled to the maximum practicable degree regardless of location").

This principle is made clear in *State of New York v. Reilly*, 969 F.2d 1147, 1153 (D.C. Cir. 1992). In that case, the court rejected EPA's decision not to ban the combustion of lead-acid vehicle batteries in its performance standards for municipal waste combustors ("MWCs"). EPA had admitted that the combustion of these batteries was "a significant source of lead in MWC emissions" and that "a ban [on their combustion] would achieve air benefit[s]," but nonetheless selected a more lenient standard that did not prohibit this practice. *Id.* Because the agency had not properly justified its decision to adopt the weaker standard, the court remanded the rule to the agency as unlawful. *Id.* Analogously, in *NRDC v. EPA*, 808 F.3d 556, 571-72 (2d Cir. 2015), the Second Circuit struck down EPA's technology-based effluent limits ("TBELs") under the Clean Water Act for ballast water discharges from ships. The Court held that EPA's TBELs, which were required to incorporate the "best available technology economically achievable" ("BAT"), were unlawful because the agency had not considered alternative systems that were both available and more protective than the one that EPA had selected as BAT. *Id.*

In short, section 111(b) performance standards and section 111(d) emission guidelines must reduce air pollution as much as possible within the parameters of what is achievable, adequately demonstrated, and not exorbitantly costly. *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999). This is particularly true with regard to CO_2 emissions from existing power plants. While *Massachusetts* affirmed that an environmental problem of such magnitude as climate change cannot be solved "in one fell regulatory swoop," 549 U.S. at 524, each source category that contributes to the problem must do its part to reduce emissions and must be controlled in a manner that is proportionate to the level of its contribution to global climate change. The United States is second only to China as the world's leading emitter of greenhouse gases, and fossil fuel-fired power plants remain the country's largest stationary source of GHG pollution. If EPA were to design an existing source rule that did not reduce power plant CO_2 emissions as much as practicable, it would violate Section 111—as well as the Administrative Procedure Act, which requires agencies to "offer a rational connection between the facts found and the choice made*," Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 52 (1983). Any rule that does not achieve deep cuts in climate-disrupting CO_2 emissions from the nation's largest stationary source of this pollution runs directly contrary not just to the agency's own factual determinations in the Endangerment Finding and afterward, but to what is evident to anyone who is alive in August 2023 and thus personally experiencing the alarming reality of climate change.

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[15] Three additional purposes are itemized, all of which aim to achieve "the prevention and control of air pollution." 42 U.S.C. § 7401(b).

III. COMMENTS ON EPA'S PROPOSED STANDARDS OF PERFORMANCE FOR NEW COMBUSTION TURBINES.

As noted above, EIA projects a substantial growth of gas-fired combustion turbine generation in the coming decades, and it is critical that these units be controlled for their CO_2 emissions to the greatest extent possible. Although EPA's standards for new combustion turbines are, for some units, premised on technological controls that could substantially reduce end-of-stack emission rates—namely, carbon capture and sequestration (CCS) and hydrogen co-firing—the proposal does not establish sufficiently stringent requirements with regard to the base-level combustion turbine technologies in themselves. In other words, the current proposal leaves important, and easily achievable, emission reduction opportunities on the table by failing to require the lowest-emitting technology and practices for all units, including those that will *also* be subject to CCS or hydrogen co-firing. In this section, we propose ways in which the agency can and must tighten these aspects of the combustion turbines standards.

EPA's proposal would create a substantial difference in rigor and cost between the largest and most frequently operated combustion turbines and the rest of the fleet. This gap incentivizes sources to comply with applicable standards by way of load-shifting from higher-capacity factor to lower-capacity factor units, which runs the risk of eroding the standards' emission reduction potential. While this differential treatment may be cost-justified for certain technological applications, such as CCS, the agency can and should reduce the stringency gap by amending certain features of the rule as it is currently written.

For instance, EPA's proposal would fully exempt *all* smaller combustion turbines (i.e., units smaller than 25 megawatts (MW) in capacity)[16] from the rule's requirements. It would also *functionally* exempt all units operating below a 20 percent capacity factor, which would have no emission reduction obligations beyond what would likely be their standard operating practice even in the rule's absence. Furthermore, despite the rule's nominal "best system" designation of 30 percent hydrogen co-firing starting in 2032 for intermediate-load units, the agency provides what amounts to a nominal emission rate that the vast majority of such operators could easily attain even without the use of hydrogen by simply constructing and operating natural gas combined cycle ("NGCC") units.

As such, under the current proposal, only EPA's standards for baseload combustion turbines—those that elect to operate at capacity factors that exceed the unit's design efficiency—are likely to achieve substantial emission reductions. In the subsections that follow, we focus on several broad strategies that will improve the efficacy of the new source standards for turbines. First, EPA must designate combined cycle (rather than simple cycle combustion turbine, or "CT") technology as part of the best system of emission reduction for intermediate-load units (as it has already done for baseload units). It must also reduce the capacity factor threshold for units qualifying for the low-load subcategory from 20 percent on an annual basis to no more than 5 to 8 percent annually and 15 percent on a monthly basis. Using an improved methodology, EPA must then recalculate the baseline emission reduction rates for all affected sources, including an output-based CO_2 standard for low-load turbines (as

[16] The EPA proposal would exempt all units that are not capable of combusting more than 250 MMBtu/hour of fossil fuels. Proposed 40 C.F.R. §§ 60.5509a(a)(1), 0.5845b(b)(2). For combustion turbines this effectively exempts units less than 25MW.

opposed to the input-based "clean fuel" standard that EPA has currently proposed). Finally, EPA must ensure that small CTs (i.e., those below 25 MW) are not exempt from the standards.

A. EPA Must Designate Combined Cycle Technology—Not Simple Cycle Technology—as Part of the "Best System" for Intermediate-Load Units.

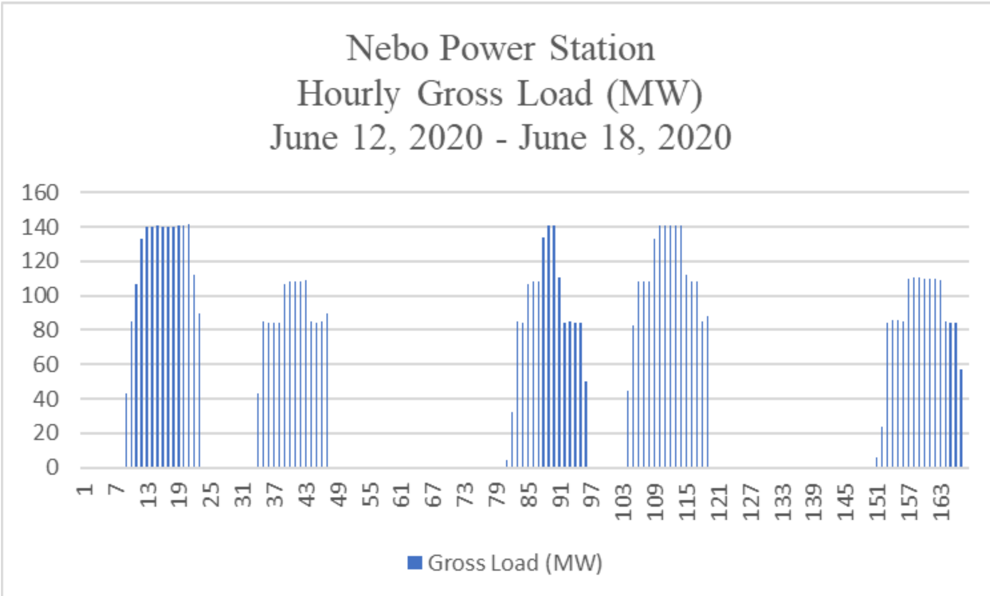
In a combined cycle or NGCC facility, the waste energy from the unit's combustion turbine is captured and employed to generate additional electricity. This provides an approximately 50 percent increase in efficiency—and an average of one-third less GHG emissions per MWh—compared to simple cycle CT technology. The NGCC's heat recovery steam generator (HRSG) is often installed after the combustion turbine has been operating for some period of time. This is not unlike retrofitting existing coal units with flue gas desulfurizers (FGD) or existing coal or gas units with selective catalytic reduction (SCR) to provide SO_2 and NO_x control, respectively.

Much of the existing combined cycle gas turbine fleet is now 20 or more years old and will soon reach a time where substantial retrofit or replacement with the most advanced new "fast-start" NGCCs will likely occur for a substantial number of units. These fast-start NGCCs initially fire the combustion turbine and quickly bring the HRSG on line. Accordingly, they can respond to rapid changes in demand while emitting far less CO_2 than the simple cycle CTs of two or three decades ago. Similarly, inlet cooling at operating units can quickly increase output by 10 percent or more of the rated output of larger NGCCs and thereby minimize the need to operate simple cycle peaking units. Weather and demand forecasting have also improved significantly, minimizing the need for "10-minute cold start" simple cycle turbines.

In fact, even NGCCs installed two decades ago—which are far less efficient than today's best units—are still capable of ramping up quickly enough to meet intermediate-load demands. For instance, the Nebo Power Station in Payson, Utah is a 140 MW combined cycle plant that commenced commercial operation on June 17, 2004.[17] It consists of a 65 MW gas turbine and a 75 MW steam turbine and has an SCR unit for NO_X control. As demonstrated below, even after 16 years of operation, this unit had no difficulty ramping up and down in a manner consistent with intermediate-load operations over the course of a representative one-week period in June 2020:

[17] All data that we cite regarding Nebo we acquired through a query to EPA's Clean Air Markets Program Database. EPA, *Clean Air Markets Program Data*, Custom Data Download (hereafter, "CAMPD query") https://campd.epa.gov/data/custom-data-download (last visited Aug. 2, 2023).

Fig. 1: Representative Hourly Gross Load of Nebo Power Station



Moreover, during this period, Nebo's emission rate was 872 lb/MWh(g), well within our proposed emission rate for intermediate-load turbines under 250 MW (*see* Table 5 below). A brand new unit equipped with the most state-of-the-art fast-start generation technology would show superior performance (and faster ramp times) still. In addition, operators may elect to employ the same fast-start and ramp-rate NGCCs that they otherwise would and, in rare instances in which an extremely short startup time[18] is required and the HRSG is not yet available, employ a bypass duct to operate the unit in simple cycle mode. While this is a suboptimal practice from both an economic and environmental standpoint, it can serve as a stop-gap for NGCCs in moments where very fast ramp-ups are required. Because our suggested emission limits are based on a rolling annual average, they provide a sufficient compliance margin to permit such infrequent and short-duration events without causing an exceedance. Further, the technology has advanced, through the use of exhaust stack dampers and revised startup routines to allow the HRSG to remain "warm" and available on short notice.[19]

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[18] The best fast-start NGCCs can operate the HRSG and steam turbine within 30 to 45 minutes of a "cold-start" firing the combustion turbine, EPA, *Efficient Generation: Combustion Turbine Electric Generating Units—Technical Support Document (TSD)*, Dkt. No. EPA-HQ-OAR-2023-0072-0060, 25–26 (May 2023), https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0060/content.pdf, whereas simple cycle CTs can achieve startup within a matter of minutes.

[19] *See id.* at 25–26. *See also, e.g.*, Modern Power Systems, *Flexibility – the new battleground*, https://www.modernpowersystems.com/news/newsflexibility-the-new-battleground/ (last visited Aug. 6, 2023); John Gülen, *Gas Turbine Combined Cycle Fast Start: The Physics Behind the Concept*, POWER ENGINEERING, June 12, 2013, https://www.power-eng.com/coal/gas-turbine-combined-cycle-fast-start-the-physics-behind-the-con/#gref; Siemens Energy, *From Base to Cycling Operation: Innovative Operational Concepts for CCPPs* (presentation delivered to Power-Gen Europe 2015 in Amsterdam, Netherlands, June 11–15, 2015), https://assets.siemens-

Despite this, EPA's proposal would broadly permit the operation of new CTs not only for peaking needs, but for intermediate-load applications as well. Intermediate-load (also known as load-following) EGUs typically operate "during the mid-morning to evening hours but [are] turned off or ramped down significantly during the night and early morning hours."[20] Thus, while these units often do not run around the clock like baseload EGUs, they frequently operate for at least half of the day and are likely to start and stop far less frequently than peaking or low-load EGUs. According to data maintained by EPA's Clean Air Markets Program Database (CAMPD), nearly 70 percent of electricity from gas-fired combustion turbines operating between 1,250 and 4,500 hours last year (the approximate range of most intermediate-load units) came from combined cycle EGUs.[21]

Yet despite the fact that combined cycle units already provide the majority of intermediate-load generation to the grid, EPA has determined that the "*best* system of emission reduction" for intermediate-load turbines is simple cycle technology. Even "new and clean," state-of-the-art simple cycle turbines typically emit one-third more CO_2 per MWh (and in some cases considerably more) than comparably sized new combined cycle units. EPA's selection of simple cycle CT technology as the baseline BSER for a generation function that NGCCs are already primarily serve units is puzzling.

In the rule preamble, the agency's rationale for setting simple cycle technology as the BSER for intermediate-load units is exceedingly brief:

> The EPA considered but is not proposing combined cycle unit design for combustion turbines in the intermediate subcategory because the capital cost of a combined cycle EGU is approximately 250 percent that of a comparable-sized simple cycle EGU and because the amount of GHG reductions that could be achieved by operating combined cycle EGUs as intermediate load EGUs is unclear. Furthermore, intermediate load combustion turbines start and stop so frequently that there might not be sufficient periods of continuous operation where the HRSG would have sufficient time to generate steam to operate the steam turbine enough to significantly lower the emissions rate of the EGU.

88 Fed. Reg. at 33,287. These assertions are in direct conflict with the facts on the ground. First, EPA's unsupported claim that the capital costs of a combined cycle units are 250 percent that of a comparable simple cycle turbine is dramatically off the mark. We analyzed four recent reports on combustion turbine costs and found that in three of those studies, overnight capital costs for new combined cycle units were *lower* on a per-kilowatt basis than for new simple cycle turbines in some or all of the scenarios presented. And the fourth study showed a far smaller cost differential between NGCCs and CTs than EPA has imagined.

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energy.com/siemens/assets/api/uuid:0cb3c09d-3464-4d29-8cfe-055b7b5dee32/t6s2p2-powergeneurope2015-base-to-cycling.pdf, included as Exhibit 1.

[20] *See Energy KnowledgeBase*, Intermediate Load, https://energyknowledgebase.com/topics/intermediate-load.asp (last visited Aug. 2, 2023).

[21] These data were accessed through a CAMPD query.

The most recent (and most conservative) report is the National Renewable Energy Laboratory 2023 Annual Technology Baseline (ATB), published in June of this year.[22] The ATB report shows the overnight capital costs of F-frame gas-fired combustion turbine in 2023 to be $995/kW. The reported overnight capital costs for F-frame combined cycle units are $1,105–$1,109/kW, while the costs for H-frame combined cycle units are $1,134–$1,141/kW. Far from 250 percent, the average cost of a new combined cycle unit vis-à-vis a simple cycle unit of equal capacity is no more than 114 percent and is as little as 110 percent. While the costs of more efficient aeroderivative turbines (which were not provided by NREL) would be higher than frame turbines, this would be true for both simple cycle and combined cycle units. In fact, the percentage cost differential between aeroderivative CTs and NGCCs would likely be *smaller* than for frame turbines, since the main cause of that delta—the cost of the HRSG—would be a smaller proportion of overall costs.

The other three analyses show even more favorable cost numbers for combined cycle compared to simple cycle units. A 2019 study prepared by Sargent & Lundy for EIA showed a similar per-kilowatt hour cost comparison between NGCC and CT units, with combined cycle EGUs having *lower* overnight costs than simple cycle units in a number of scenarios.[23] A 2019 analysis by the California Energy Commission (CEC) found lower per-kilowatt overnight capital costs for combined cycle EGUs in most instances relative to simple cycle turbines, with the mid-case NGCC estimates ranging from $890 to $914/kW and the mid-case CT estimates ranging from $971 to $1,190/kW.[24] Comparing levelized costs of electricity, CEC reported mid-case combined cycle estimates of $118–$119/MWh and mid-case simple cycle estimates ranging from $409 to $746.[25]

Finally, a 2018 study prepared for PJM by the Brattle Group and Sargent & Lundy found that the overnight capital costs of a new 2x1 combined cycle equipped with GE 7HA.02 combustion turbines ranged from $772 to $883/kW while the costs for a new simple cycle unit, also using a GE 7HA.02, ranged from $799 to $898/kW.[26] The study notes that

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[22] Nat'l Renewable Energy Laboratory, *Related Datasets 2023 Annual Technology Baseline (ATB) Cost and Performance Data for Electricity Generation Technologies*, 2023_v1_Workbook_06_28_23.xlsx (tab titled "Natural Gas_FE"), https://data.openei.org/files/5865/2023%20v1%20Annual%20Technology%20Baseline%20Workbook%20Original%206-28-2023%20(1).xlsx, included as Exhibit 2.

[23] Sargent & Lundy Consulting, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, Table 2—Cost & Performance Summary Table (Dec. 2019), https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf, included as Exhibit 3.

[24] Cal. Energy Comm'n, E*stimated Cost of New Utility-Scale Generation in California: 2018 Update*, Table B-25 (May 2019), https://www.energy.ca.gov/sites/default/files/2021-06/CEC-200-2019-005.pdf, included as Exhibit 4.

[25] *Id.*

[26] The Brattle Group/Sargent & Lundy Consulting, *PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date*, Table 9: Plant Capital Costs for CT Reference Resource in Nominal $ for 2022 Online Date and Table 10: Plant Capital Costs for CC Reference Resource in Nominal $ for 2022 Online Date (Apr. 19, 2018) https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx, included as Exhibit 5.

> while the capacity of the [NG]CCs plants has almost *doubled* compared to that in the 2014 CONE Study, the cost of the gas turbines increased by 50%, and the cost of the steam section of the [NG]CC (including the heat recovery steam generator and steam turbine) increased by only 30%. CT plants share the same economies of scale on the combustion turbine itself, but not the greater economies of scale that [NG]CCs enjoy on their steam section or other balance of plant costs.[27]

The data from each of the four reports are presented in the table below.

Table 1: Comparison of NGCC and CT Overnight Capital Cost Estimates

Source of cost estimate	**Combined cycle unit – capacity/heat rate**	**Capital cost ($/kW)**	**Simple cycle unit - capacity/heat rate**	**Capital cost ($/kW)**
NREL (2023)	F Frame- 727 MW/ 6363 Btu/kWh H Frame- 992 MW/ 6196 Btu/kWh	$1105–09 $1134–41	F Frame- 233 MW/9,717Btu/kWh	$995
EIA AEO (Sargent & Lundy) (2019)	GE 7HA.02 2x2x1- 1083 MW/6370 Btu/kWh H Class 1x1x1- 418 MW/6431 Btu/kWh	$958 $1084	2 x LM 6000- 105 MW/9124 Btu/kWh 1x GE 7FA- 237 MW/9905 Btu/kWh	$1175 $713
Cal Energy Comm'n (2019)	640 MW/7250 Btu/kWh 700 MW/7250 Btu/kWh	$914 (mid-case) $890 (mid-case)	NextGen LM6000- 49.9 MW/10,585 Btu/kWh 2 x NextGen LM6000- 100 MW/10,585 Btu/kWh 200 MW/9880 Btu/kWh	$1190 (mid-case) $1185 (mid-case) $971 (mid-case)
PJM (The Brattle Group/Sargent & Lundy) (2018)	GE 7HA.02 2x1- 1140 MW/~6300 Btu/kWh	$772–873	GE 7HA.02- 320 MW/~927- Btu/kWh	$799–898
Average of Studies		**$988**		**$1011**

[27] *Id.* at 52–53 (emphasis in original).

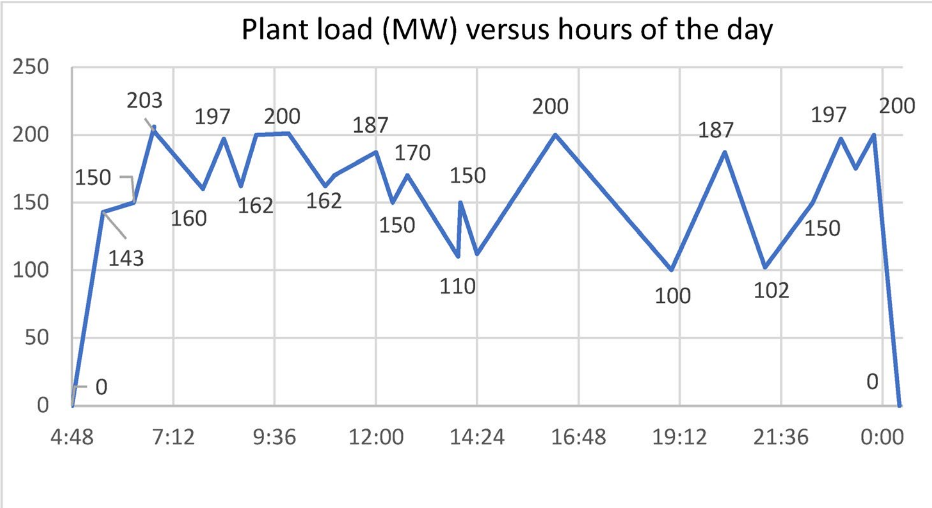
EPA's assertion that a new combined cycle units capital costs are two-and-a-half times those of comparably sized simple cycle turbine is thus flatly wrong: the average of the studies cited above indicate that NGCCs are *cheaper* on a per-kW basis than CTs.

EPA's second assertion that "the amount of GHG reductions that could be achieved by operating combined cycle EGUs as intermediate-load EGUs is unclear" makes little sense. It is an undisputed fact that combined cycle technology is far more efficient than simple cycle technology and produces far lower emissions for the same quantity of electricity generated. This is apparent even from the performance of the current fleet of gas turbines, which includes many old units and obsolete plant designs and does not fully reflect the greater efficiency of today's best NGCCs. As noted above, close to 70 percent of all intermediate-load generation in 2022 was provided by existing (and, in many cases, aging) combined cycle facilities.[28] These EGUs' emissions rates were approximately 20 percent lower than those of the simple cycle units that also operated between 1,250 and 4,500 hours per year.[29] Again, for "new and clean" EGUs using the best technology available today, this differential would be much higher. Although hours of operation are not a perfect proxy for intermediate-load operation, these figures leave little doubt that, even for an aging fleet, combined cycle generation provides significantly lower emissions for intermediate-load operation than simple cycle generation.

Finally, EPA claims that "intermediate load combustion turbines start and stop so frequently that there might not be sufficient periods of continuous operation where the HRSG would have sufficient time to generate steam to operate the steam turbine enough to significantly lower the emissions rate of the EGU." 88 Fed. Reg. at 33,287. If this were true, then the data presented above would look very different, rather than reveal a 20 percent gap in emission rates even with considering older, less efficient combined cycle models rather than the far more efficient units now available. Furthermore, frequent starting and stopping is not characteristic of intermediate-load units, which typically run from mid-morning until evening and then ramp down or turn off at night. The figure below depicts the typical operation of an intermediate-load combined cycle unit over the course of the day. While its load indeed fluctuates, the unit does not start and stop frequently, as EPA suggests, but instead only shuts off entirely for approximately five hours when demand is lowest.

[28] These data were accessed through a CAMPD query.
[29] *Id.*

Fig. 2: Daily Load Pattern of Intermediate-Load NGCC Unit[30]



EPA's selection of simple cycle technology as the BSER for intermediate-loads units does not hold up in the face of this analysis, particularly in light of the fact that the agency has not provided a cost-effectiveness or technical analysis to support its decision. Of course, the options for gas-fired generation vary widely in efficiency, and the more efficient units employ more sophisticated technologies and materials and may have a higher capital cost for similarly sized facilities (although the CEC, Brattle Group, and S&L studies suggest that this is often *not* true when comparing across CTs and NGCCs). Yet capital costs are only one part of the picture: cost-effectiveness—which EPA traditionally evaluates in setting the BSER—depends not only on an estimate of different options' capital costs, but also future gas prices, utilization of the unit over a period that spans decades, and—critically—the value of the pollution abated as a result of those expenditures.

It may well be the case that an operator is reluctant to pay a higher initial cost to achieve a higher efficiency, even if the costlier upfront investment is fully justified from an environmental (and, in some cases from a purely economic) standpoint. Additionally, capital cost considerations may dominate an operator's decision in regulated markets that allow it to pass through fuel costs to customers, making efficiency a secondary consideration. Yet if facility owners' perceptions of their own economic interests were the driving factor of environmental policy, there would be no need for regulation in the first place. This is precisely why EPA's argument based on capital costs would fall short *even if it were correct* (which, in most cases, it is not): it substitutes the short-term thinking of a plant operator with the longer-term thinking needed for EPA to properly serve the public interest and fulfill its statutory duty.

As depicted above, the average of the four studies discussed above (NREL, EIA, CEC, and PJM) show lower overnight capital costs for NGCCs compared to CTs on a per-kW basis. Thus, any cost-effectiveness analysis based on that average would necessarily show that an operator's decision to

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[30] Hiyam Farhat and Coriolano Salvini, *Novel Gas Turbine Challenges to Support the Clean Energy Transition*, 15 ENERGIES 5474, Fig. 7 (2022), https://doi.org/10.3390/en15155474, included as Exhibit 6.

construct and operate a new NGCC rather than a new CT would yield both net environmental benefits and net financial savings at every capacity factor. However, to understand how this calculus might play out under a conservative scenario, we compared the annualized costs and monetized CO_2 emissions of two new, comparably sized NGCC and CT units using the data from the NREL study, which were *least* favorable to NGCCs of those included in the table above. Our sources, assumptions, and methodology are described below.

Source of cost and emission assumptions:

- The cost of NGCC ($1,109/kW) and CT ($995/kW) generation capacity reflect overnight capital cost figures provided in NREL's ATB report.[31]
- Our assumed cost of gas ($3.69), amortization period (30 years), and annual interest rate (7 percent) match EPA's own assumptions from the proposed rule when determining the cost-effectiveness of the CCS component of the "best system" for baseload turbines. 88 Fed. Reg. at 33,298 n.340.
- For the capital recovery factor, we used Engineers Edge *Capital Recovery Formula and Calculator.*[32]
- CO_2 emission rates for comparably sized NGCC and CT units were based on 2021 CAMPD emission data for Bayonne Energy Center (Siemens SGT 600), Lordstown Energy Center (Siemens 600 SGT with HRSG) and Holland Energy Park (Siemens SGT 800 with Siemens SST 400 steam generator and HRSG), converted to net emission rates by a factor of 1.03.
- For the social cost of carbon, we used the federal Interagency Working Group (IWG) central estimate for 2035, which is $67/metric ton.[33]

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[31] *See* n. 22, *supra*.

[32] Engineers Edge, *Capital Recovery Formula and Calculator*, https://www.engineersedge.com/calculators/capital_recovery_factors_15667.htm (last visited Aug. 3, 2023).

[33] Interagency Working Group on Social Cost of Greenhouse Gases, *supra* n. 6, at Table A-1. The IWG's values are highly conservative estimates that very likely underreport the true social harm that CO_2 emissions impose on society. *See, e.g.*, Inst. for Policy Integrity, et al., *Comments on the Consideration of the Social Cost of Greenhouse Gases in "Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles," 88 Fed. Reg. 29,184 (proposed May 5, 2023)*, 26, 30–32 (July 5, 2023), included as Exhibit 7. In addition, the Office of Management and Budget (OMB) recently proposed a new discounting protocol that would set the default discount rate for regulations at 1.7 percent. OMB, *Circular A-4: Draft for Public Review*, 75–76 (Apr. 6, 2023), https://www.whitehouse.gov/wp-content/uploads/2023/04/DraftCircularA-4.pdf. Calculations using a less conservative social cost of carbon (such as Resources for the Future's recommendation of $185/metric ton) or a lower discount rate would provide considerably more support for our argument that NGCC are both economically and environmentally preferable to CTs in the vast majority of applications. Kevin Rennert, et al., *Comprehensive evidence implies a higher social cost of CO_2*, 610 NATURE 687–692, https://www.nature.com/articles/s41586-022-05224-9, included as Exhibit 8.

Methodology:

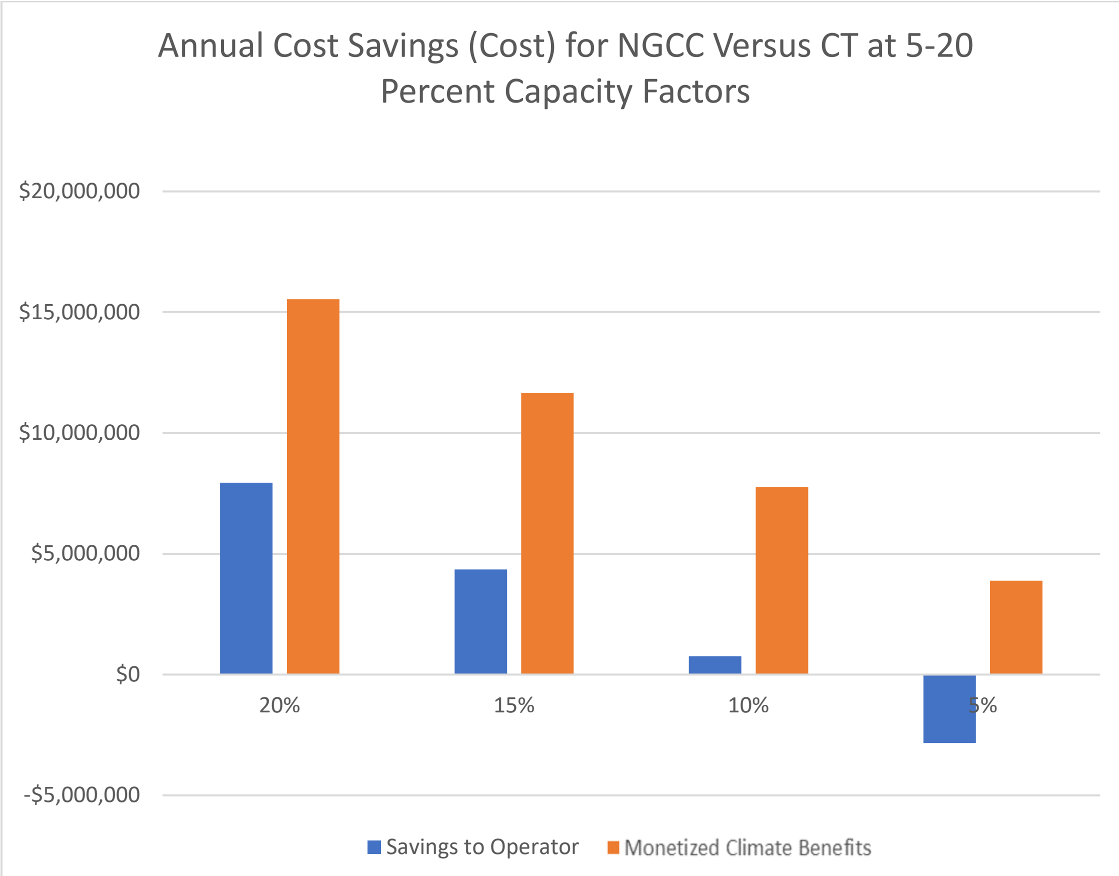
- Our analysis considered the relative cost-effectiveness of new CTs and NGCCs at four annual capacity factors: 20, 15, 10, and 5 percent. We evaluated two hypothetical units: one new CT and one new NGCC. Our hypothetical simple cycle unit consist of three 233 MW GE F-class combustion turbines with a total capacity of 699 MW, while our hypothetical combined cycle unit consists of two of the same GE turbines as well as an HRSG and gas turbine/generator, configured in a 2x1 arrangement, also with 699 MW of capacity. Although the NGCC evaluated in the NREL study was 727 MW in capacity, we normalized it to 699 MW to provide equivalent generation with the CT unit at each capacity factor, and thus allow for an apples-to-apples comparison.
- Our calculations produced five values for the two hypothetical units:
    - **Annual capital costs:** To calculate this figure, we multiplied NREL's per-kW overnight capital cost figures for new NGCCs and CTs by the respective generation capacities of our two hypothetical units. We then calculated an annualized cost figure for each facility, using EPA's assumptions of a 30-year amortization period and an interest rate of 7 percent.
    - **Annual fuel costs:** To determine the annual quantity of gas consumed by each unit, we divided each source's assumed emission rate in lb/MWh by the heat content of gas (115 lb/MMBtu), then multiplied the resulting quotient by each source's annual generation total at the capacity factor under evaluation. This calculation yielded each facility's total annual fuel consumption in MMBtu, which we multiplied by EPA's assumed cost of gas ($3.69/MMBtu) to determine annual fuel costs.
    - **Annual operator costs:** This column simply reflects annualized capital costs plus annual fuel costs. We did not account for annual operation and maintenance costs, but these are very small, and thus effectively trivial, in comparison to capital and fuel costs.
    - **Annual CO_2 emissions:** This figure represents each unit's assumed emission rate, which, as noted above, reflects in-use CAMPD data for comparable NGCC and CTs, multiplied by the unit's capacity, 8,760 hours per year and the annual capacity factor under evaluation.
    - **Annual social cost of CO_2 emissions:** To calculate this figure, we converted each unit's annual CO_2 emissions to metric tons and multiplied that figure by $67/metric ton, the IWG's 2035 social cost of carbon at a 3 percent discount rate.

The calculation results are presented below. The figures highlighted in orange reflect the overall economic benefit of operating the NGCC unit rather than the CT as well as the monetized climate benefit.

Table 2: Cost-Effectiveness Comparison of Comparable Combined Cycle and Simple Cycle Units

	Overnight capital costs	Fuel costs	Operator's cost	CO_2 emissions (mt)	Social cost of CO_2 emissions
20% Capacity Factor					
3 F-class CTs (699 MW)	$56,050,748	$48,375,179	$104,425,927	758,579	$52,341,964
F-class 2x1 NGCC (727 MW)	$62,472,643	$34,013,797	$96,486,440	533,376	$36,802,944
Incremental Benefit for NGCC	-$6,421,895	$14,361,381	$7,939,486	225,203	$15,539,021
15% Capacity Factor					
3 F-Class CTs (699 MW)	$56,050,748	$36,281,384	$92,332,132	568,934	$39,256,473
F-Class 2x1 NGCC (727 MW)	$62,472,643	$25,510,348	$87,982,991	400,032	$27,602,208
Incremental Benefit for NGCC	-$6,421,895	$10,771,036	$4,349,141	168,902	$11,654,265
10% Capacity Factor					
3 F-Class CTs (699 MW)	$56,050,748	$24,187,589	$80,238,337	379,290	$26,170,982
F-Class 2x1 NGCC (727 MW)	$62,472,643	$17,006,899	$79,479,541	266,688	$18,401,472
Incremental Benefit for NGCC	-$6,421,895	$7,180,691	$758,796	112,602	$7,769,510
5% Capacity Factor					
3 F-Class CTs (699 MW)	$56,050,748	$12,093,795	$68,144,543	189,645	$13,085,491
F-Class 2x1 NGCC (727 MW)	$62,472,643	$8,503,449	$70,976,092	133,344	$9,200,736
Incremental Benefit for NGCC	-$6,421,895	$3,590,345	-$2,831,549	56,301	$3,884,755

Fig. 3: Net Economic and Environmental Benefits of Combined Cycle Operation Relative to Simple Cycle Operation



The data provided above are stark: under the 20, 15, and 10 percent capacity factor scenarios, combined cycle operation is far more environmentally beneficial compared to simple-cycle operation *and* more economically advantageous to operators and ratepayers, as the savings in fuel costs resulting from the NGCC's superior efficiency exceed its additional capital costs in each case. Only under the 5 percent capacity factor scenario do the ratepayers see higher costs as a result of combined cycle operation, and yet even then, the social benefits of reduced CO_2 emissions outweigh those economic disbenefits.

Given the clear economic and environmental advantage of operating combined cycle unit even at low capacity factors, one may wonder why so many existing simple cycle units nonetheless continue to operate at levels above single-digit capacity factors. There are two basic answers to this. First, because simple cycle units invariably have higher marginal operating costs than combined cycle facilities, a given CT will only be called upon to dispatch when all of the available NGCCs in a given load-balancing area are already up and running. Second, a large portion of the combined cycle fleet was constructed approximately 20 years ago, when fast-start NGCCs—which are far superior to older, conventional NGCCs to use for peaking purposes and operating at lower capacity factors—were not available. Thus, simple cycle units have provided much of the generation at lower capacity factors, and have operated at higher capacity factors when combined cycle generation has been effectively maxed out in a given service area.

This is a description of how the gas fleet has operated for the last two decades given the economic and technical factors from 20 years ago. Yet in this rule proposal, EPA is determining what to require for combustion turbines *going forward*. The purpose of section 111(b) standards is not simply to accommodate the practices that the industry currently follows. On the contrary, it is designed as a "technology-forcing" provision. As the D.C. Circuit has held, "EPA does have authority to hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard." *Sierra Club v. Costle*, 657 F.2d 298, 364 (D.C. Cir. 1981). The data above show that it is not just feasible but advantageous to require combined cycle technology for units operating at capacity factors considerably lower than 20 percent, and certainly at whatever range EPA ultimately selects for intermediate-load units.

B. EPA Must Reduce the Annual Capacity Factor Threshold Distinguishing Low-Load and Intermediate-Load Operation From 20 Percent to No More than 5 to 8 Percent and 15 Percent on a Monthly Average Basis.

The subsection above demonstrates that EPA's decision to establish simple cycle technology as a component of the "best system" for intermediate-load units is unsupported, and that combined cycle technology is the appropriate designation for that subcategory. The data also strongly called into question EPA's decision to set the cut-point separating the low-load from intermediate-load combustion turbine subcategories at an annual capacity factor as high as 20 percent. This 20 percent threshold does not correspond to actual peaking operations, and EPA's selection of simple cycle generation as the "best system" is only justified for units that operate at capacity factors of no more than 5 to 8 percent. Accordingly, to the extent that EPA retains simple cycle technology as the BSER for low-load units, it must limit that subcategory to units operating at those capacity factors and lower.

It is important to observe here that EPA has not proposed an output-based emission standard for new low-load combustion turbines. Instead, it establishes an input-based standard ranging from 120 to 160 pounds of CO_2 permitted for each MMBtu of heat input. Yet 120 lb/MMBtu figure—which applies to units that "derive[] [their heat input] from natural gas," 40 C.F.R. § 60. 60.5525a(a)(2)—simply reflects the CO_2 content of standard gas itself. 88 Fed. Reg. at 33,259. This leads to what is, in practice, a regulatory tautology: units that derive their heat input from gas must, to meet the standard, burn gas. And the looser standard of 160 lb/MMBtu figure, which applies to units other than those firing gas, corresponds to the CO_2 content of petroleum products such as diesel or distillate fuel oil, *id.*—again, the very fuels that these sources would be firing in any event if they were not firing gas.

Therefore, EPA's proposed standards for low-load units will not achieve any emission reductions beyond business-as-usual. As discussed below, the agency should reformulate these standards as output-based emission rates based on the most efficient technologies available for that operational mode. Regardless of how EPA formulates this standard, it will likely to determine that these units' low frequency of operation rules out the more aggressive CCS and hydrogen emission reduction techniques that the agency has included in the "best system" for intermediate-load and baseload turbines. However, there is a substantial difference in performance between aeroderivative CTs, such as the LM Series, SWIFTPAC Series and SGT Series units, and others on the market. EPA should establish an "ISO new and clean" limit to ensure that only the most efficient units are purchased and an in-use operating limit, based on the performance of these units, rather than older, less efficient designs. We describe this approach in more detail, and propose emission rates based on it, in the following subsection.

But even the most state-of-the-art CTs are far less efficient, and thus emit much more CO_2, than fast-start NGCCs, which can operate effectively on short-notice and thus meet load-following operational needs. For this reason, it is all the more critical from an environmental perspective that EPA limit the low-load subcategory to the greatest extent possible and take pains to ensure that it does not encompass anything other than true peaking units. The current upper limit of a 20 percent annual capacity factor is far too high to prevent inefficient CTs from being used as seasonal baseload units (a phenomenon we discuss more below), and would include in this largely uncontrolled category a large number of units that can and should be expected to achieve much lower emission rates.

In the preamble, EPA describes its selection of simple cycle technology as the BSER for low-load operations using largely the same justifications it deployed with respect to the intermediate-load subcategory:

> The EPA expects that units in the low load subcategory will be simple cycle turbines. The capital cost of a combined cycle EGU is approximately 250 percent that of a comparable sized simple cycle EGU and would not be recovered by reduced fuel costs if operated as low load units. Furthermore, low load combustion turbines start and stop so frequently that there might not be sufficient periods of continuous operation for the HRSG to begin generating steam to operate the steam turbine enough to significantly lower the emissions rate of the EGU.

88 Fed. Reg. at 33,286. In the previous subsection, we explained how EPA's assumptions about the relative capital costs of CTs and NGCCs badly misses the mark, and that that NGCCs operating at 20, 15, and 10 percent capacity factors—and somewhat lower still—*could* recover those additional capital costs through conserved fuel. More importantly, ensuring that an operator pays no additional money to achieve pollution reductions *is not the legal standard of section 111.* The agency acts as though *any* quantity of compliance costs are unacceptable if an operator cannot fully defray them through operational savings. Yet in *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999), the D.C. Circuit held that EPA must only ensure that the costs of its standards are not "exorbitant." Similarly, in *Portland Cement Ass'n v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975), the court held that the regulatory costs of the BSER must not be "greater than the industry could bear and survive."

Furthermore, by foreclosing an environmentally superior control option merely because it would entail *some* additional capital costs that an operator cannot fully recoup, EPA unlawfully and arbitrarily treats costs as determinative of the "best system," ignoring the other statutory factors such as the amount of pollution reduced. The statute requires EPA to balance these different factors, not to prioritize one over all the others. For this reason, EPA typically determines whether section 111 costs are reasonable not by considering them in isolation, but by calculating the dollars an operator must spend to reduce each ton of pollution. As discussed previously, even using the most conservative capital cost estimates, the monetized CO_2 benefits of constructing and operating an NGCC rather than a CT outweigh any additional compliance costs even at the lowest capacity factor analyzed.

As for frequent starts and stops, EPA has not shown that fast-start NGCCs cannot fill this need; it assumes, without further analysis, that only CTs can. As demonstrated above, though, modern NGCCs can meet this need as well. In fact, EPA's own Technical Support Document *titled Efficient Generation: Combustion Turbine Electric Generating Units* makes this exact point:

> Improving startup time of combined cycle EGUs makes combined cycle EGUs a more dependable power source for load-following supply, and research/practice suggests several ways to improve combined cycle startup times. Combustion turbines operating as EGUs in a combined cycle system have historically been designed to operate for extended periods of time at steady loads. Since these combined cycle EGUs were not intended to start and stop on a regular basis, they had relatively long startup times depending on unit-specific factors and whether startup was initiated from a cold, warm, or hot state. During the past decade, the demands placed on this conventional mode of steady, base load operation have changed. The latest combined cycle EGUs are designed with advanced technology and features to be more flexible and respond faster to increased demand for reliable electricity, support increased generation from intermittent sources (*i.e.*, renewables), capitalize on financial incentives to improve dispatch or supply non-spinning reserves, operate at higher efficiencies, and emit less pollution. As a result, advanced fast-start, combined cycle EGUs incorporate multiple techniques that allow the EGU to start and stop faster, cycle output faster, and maintain higher part-load efficiencies than previous designs.
>
> Several combustion turbine manufacturers market complete combined cycle systems that can ramp up to full load from a cold start in less than an hour, depending on unit-specific factors. Advanced combustion turbines, when isolated from the HRSG and steam turbine, can reach full load at full speed as a simple cycle (*i.e.*, Brayton) unit in less than 20 minutes. When adhering to some of the following fast-start techniques, the HRSG, steam turbine, and balance of plant equipment can reach safe operating temperatures and pressures and begin generating additional electricity within 30 to 45 minutes of ignition of the combustion turbine. Techniques that can be used to reduce startup times for combined cycle systems are discussed below.[34]

Our primary objection here is that EPA has defined its low-load peaking category far too broadly, and in doing so, will allow CTs to operate at much higher frequencies than they should given the availability of fast-start NGCCs. The agency bases the 20 percent capacity factor cut-point between its low- and intermediate-load subcategories on two factors. First, it asserts that simple cycle turbines exhibit variable emission rates at lower loads, and so it is difficult to establish a single output-based

[34] EPA, *supra* n. 18, at 25.

limit (which is appropriate for intermediate-load units) that would accommodate the range of sources operating in those thresholds. 88 Fed. Reg. at 33,321. Second, it claims that two-thirds of simple cycle units constructed in recent years have operated above a 10 percent capacity factor, and that some of these units would have difficulty complying with an intermediate-load standard. *Id.* The agency solicits feedback on capacity factors ranging from 15 to 25 percent as the appropriate threshold, but is ostensibly not considering capacity factors below 15 percent based on these two considerations. *Id.*

EPA's reasoning suffers from both legal-conceptual and empirical flaws. On a conceptual level, the agency again treats section 111(b) as a technology-following rather than technology-forcing provision, failing to appreciate that "section 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present." *Nat'l Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 785 (D.C. Cir. 1976) (cleaned up). That some newly constructed simple cycle units have, during periods of low gas prices, operated at capacity factors between 10 and 15, or between 10 and 20 percent, does not mean that EPA cannot hold the industry to a stricter standard, particularly given the advantages that combined cycle units have over simple cycle units even at low usage rates.

On a purely factual level, EPA's 20 percent threshold does not accurately reflect levels of operation associated with peaking generation. For example, the New England Independent System Operator defines a peaking unit as follows:

> A generating unit usually on line to meet power system requirements during very high, peak-day load periods when the demand on the system is the greatest and that may be used in response to system contingencies because they can start up quickly on demand and operate for only a few hours; typically operates less than 10% of the year (i.e., a few hundred hours per year) and at a relatively high cost (i.e., when the price of electric energy is high).[35]

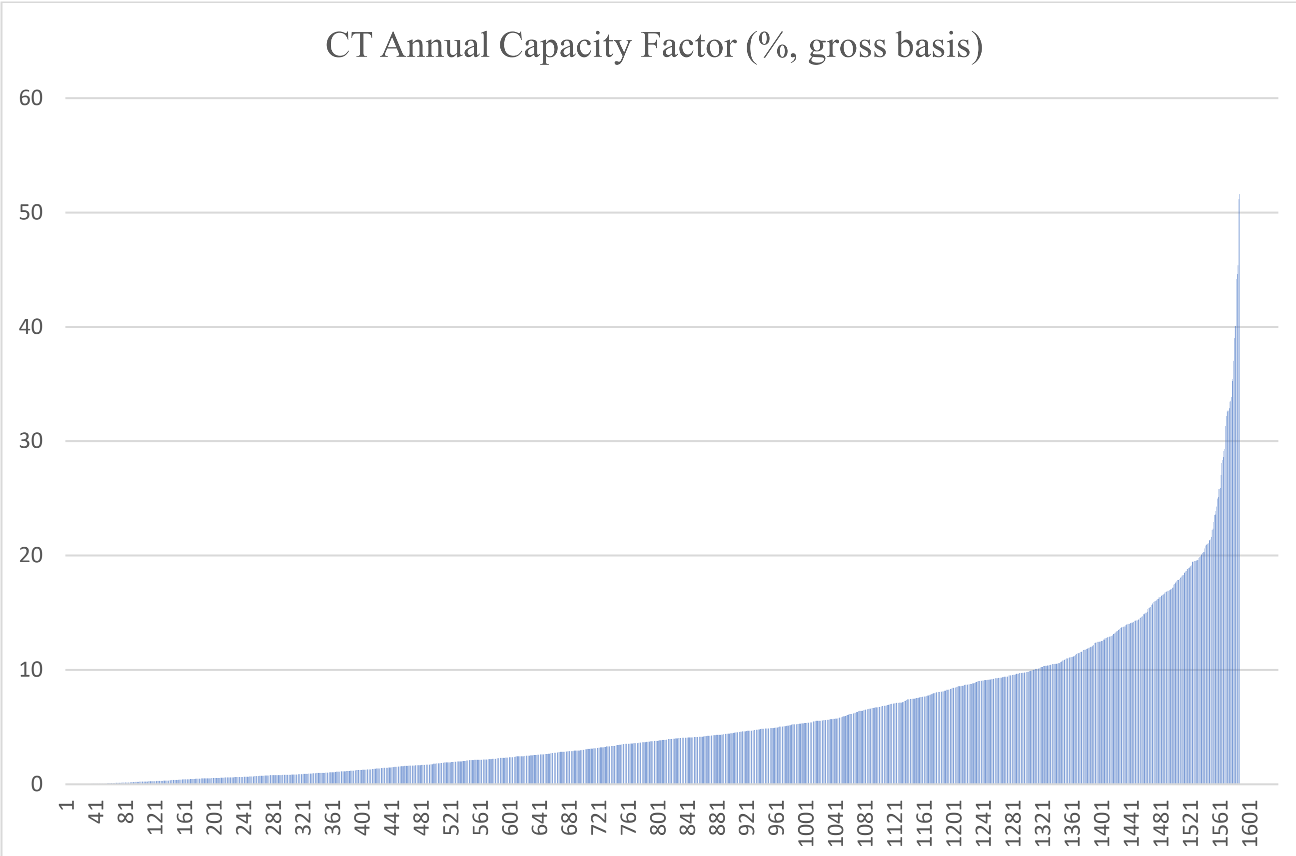
General Electric, one of the largest manufacturers of gas-fired turbines, cites the American National Standards Institute[36] definition of peak load operation as 1,250 hours per year with five hours per start.[37] Indeed, EPA's own data reveal that over 70 percent of existing CTs already run at capacity factors below 8 percent:

[35] ISO New *England, Glossary and Acronyms* (definition of "peak-load generating unit, peaking unit), https://www.iso-ne.com/participate/support/glossary-acronyms/ (last visited Aug. 2, 2023).

[36] The American National Standards Institute is a private nonprofit organization that oversees the development of voluntary consensus standards for products, services, processes, systems, and personnel in the United States.

[37] *See* General Electric, *GE Gas Turbine Performance Characteristics,* GE Power Systems Publication GER-3567H, 14 (Oct. 2000), https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/resources/reference/ger-3567h-ge-gas-turbine-performance-characteristics.pdf, included as Exhibit 9.

Fig. 4: 2021 CT Capacity Factors by Unit[38]



The California Energy Commission report referenced above similarly demonstrates the capacity factors at which simple cycle units generally operate.

[38] This chart reflects data from EPA, *Technical Support Document: Simple Cycle Stationary Combustion Turbine EGUs - Supporting Data*, Dkt. No. EPA-HQ-OAR-2023-0072-0046, Attachment 1, Figs. 4, 5, and 6 (May 2023), https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0046. EPA's analysis included in this TSD is flawed in that it looks at each unit's highest utilization over a 10-year period. This results in a level of overall generation that is higher than was experienced by the group as a whole in any year. It is also worth noting that this data set covers CTs above 25 MW; if it were not so limited, it would likely show a much smaller percentage still of units operating at high capacity factors.

Table 3: California Energy Commission's Assumed Capacity Factors for New Combustion Turbine Designs[39]

Technology	Owner	Assumed Capacity Factor		
		Mid Case	High Case	Low Case
Conventional CT (both sizes)	Merchant	4.0%	1.5%	8.0%
	POU	4.5%	1.5%	7.5%
	IOU	4.0%	1.0%	7.0%
Advanced CT	All Owners	7.0%	4.0%	10.0%
Conventional CC	All Owners	57.0%	40.0%	71.0%
Conventional CC w/Duct Burners	All Owners	57.0%	40.0%	71.0%

Note: High and low are based on cost implications, not on the specific value of the capacity factor.

The CEC data indicate that the typical capacity factors for simple cycle (and, thus, most peaking) units are nowhere near 20 percent—let alone intermediate-load ranges—but are in the range of 1 to 10 percent range.

Furthermore, a peaking subcategory based on annual capacity factors above 5–8 percent will cover units that, in practice, do not operate as peakers. The Zion Energy Center in Zion, Illinois provides a clear example of this. This facility consists of three 198.9 MW GE simple cycle turbines that the company describes as "peaking units."[40] These units operate only sparingly other than in the summer, with annual capacity factors of 13.42 percent and annual emission rates of 1,240 lb/MWh.[41] Because they fall well below EPA's capacity factor threshold for the low-load/peaking subcategory, all three units in the plant would, if new, be effectively exempt from any emission reduction requirements under EPA's proposal beyond BAU. Consider, however, Figures 5 and 6 below, which depict the hourly load pattern for Zion Unit One in the summer of 2020. The operational data for this unit reveal few cold starts (which would be necessary for peaking application) and show that, for the vast majority of the hours during that summer, Zion's hourly gross load fell within a narrow band between 156 MW and 169 MW. A better description of the function of this unit might therefore be "seasonal baseload" or at least "seasonal load-following."

[39] Cal. Energy Comm'n, *supra* n. 24, at Table B-19: Estimated Capacity Factors for Natural Gas Technologies. The Commission based these assumptions on the historical monthly data it received through its Quarterly Fuel and Energy Report.

[40] Calpine, *Zion Energy Center*, https://www.calpine.com/zion-energy-center (last visited Aug. 2, 2023).

[41] This figure, as well as all data for Zion Energy Center and the figures and table depicting those data, were accessed through a CAMPD query.

Fig. 5: Zion Energy Center Unit One, Hourly Gross Load—June 1, 2020–August 31, 2020

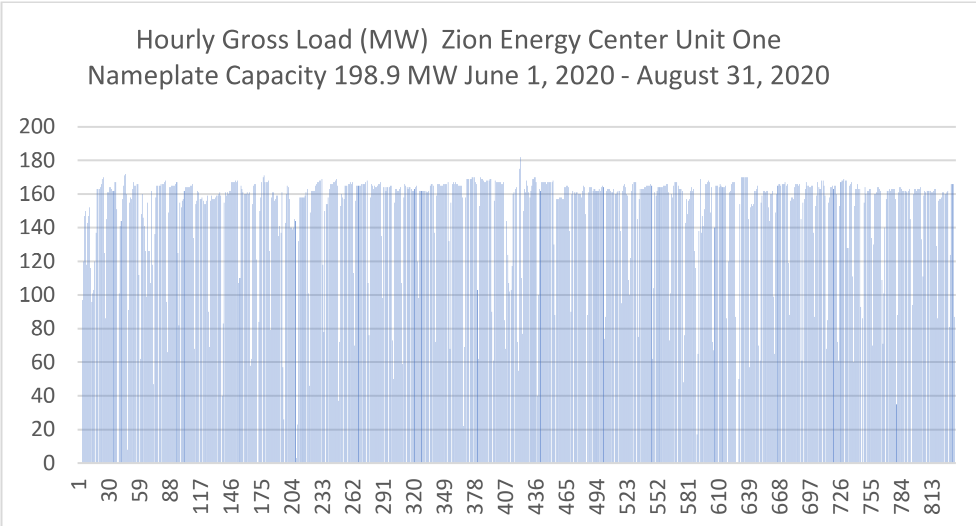
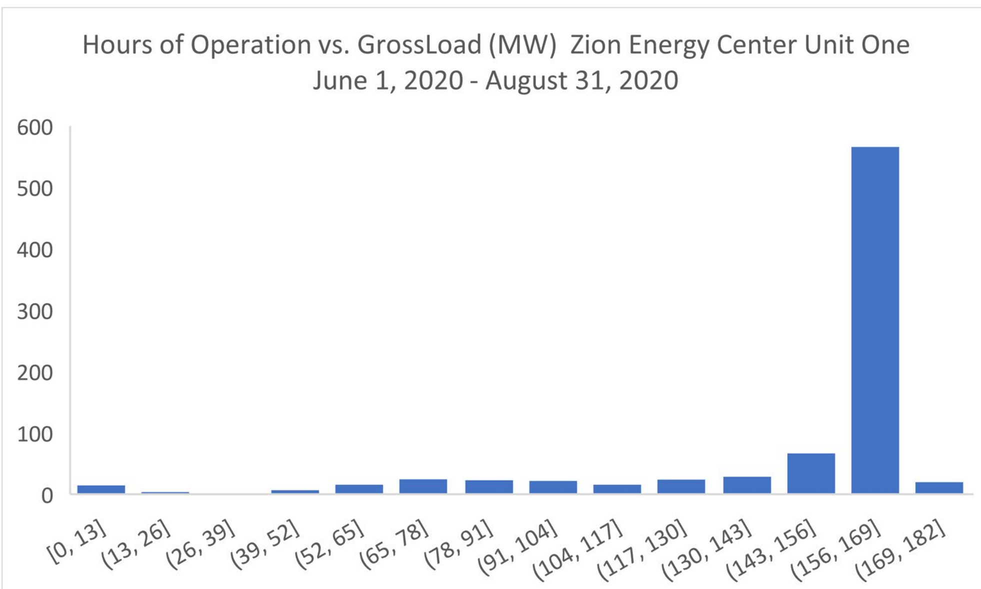
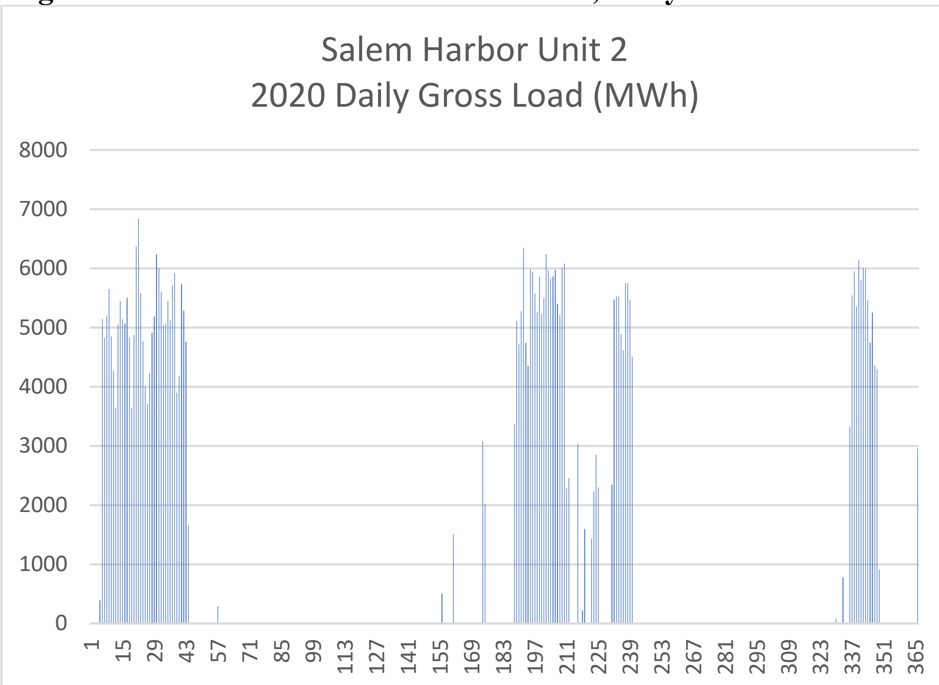


Fig. 6: Zion Energy Center Unit One, Histogram–Hours of Operation within Load Bin (MW)



Simply put, this is not a peaking unit. From both environmental and technical standpoints, there is no justification to operate a simple cycle unit in this manner; the load of Zion Unit One and its two sister CTs could and should be served by a combined cycle facility. An example of such a facility is Salem Harbor Power Station Unit 2, which is a 1x1 fast-start combined cycle generator. As shown in the figure below, this unit operates seasonally, meeting load in much of the winter and summer and turning off during other times.

Fig. 7: Salem Harbor Power Station Unit 2, Daily Gross Load in 2020



Thus, even while combined cycle operation is both demonstrated and superior for seasonal operations of this nature, plants like Zion would, under the Proposed Rule, receive a free pass to perform baseload functions during significant swathes of the year and emit essentially unchecked amounts of CO_2. The table below contrasts Zion Unit One's 2020 emissions performance (along with two other CTs that operated in a similar manner) with Salem Harbor Unit 2 in that year:

Table 4: Operating Hours and Performance of "Seasonal" CTs vs. Intermediate-Load NGCC

Unit	2020 Operating Hours	2020 Emission Rate (lb/MWh)	Model	Design
Zion Unit One CT	1634	1240	GE	[data not available]
Ecton Two CT	2520	1329	GE 7FA	Frame CT
Antelope CT	1790	1198	GE7F.05	Frame CT
Salem Harbor Unit 2 NGCC	2142	857	GE 7F	GE FlexEfficiency 60

These data all point in one direction: EPA's 20 percent capacity factor threshold for low-load units—which, under the proposal, have effectively no emission reduction obligations—does not reflect true peaking applications. It would permit units that should have combined cycle technology to use inferior simple cycle configurations and is neither the optimal environmental nor economic selection. Consistent with the actual peaking operations, as well as the data provided in the previous section on the cost-effectiveness of different turbine designs, EPA should set the threshold for low-load units at no greater than 5 to 8 percent on an annual basis *and* 15 percent on a monthly average basis. These constraints are necessary to prevent CTs from operating in seasonal baseload or load-following applications (as demonstrated by Zion Unit One) or otherwise generating at frequencies far better suited for NGCCs.

The agency's claim that CTs experience variable emission rates below approximately 15 percent should be no barrier to this revised threshold. EPA's observation is limited to simple cycle turbines, but as demonstrated in the previous section of these comments, new combined cycle units are, in fact, more cost-effective to operate than new CTs down to capacity factors between 5 and 8 percent, and provide net environmental benefits at *all* capacity factors examined. Given the commercial availability of fast-start NGCCs and the standard definition of peaking operations as annual capacity factors of between approximately 5 to 8 percent, it is entirely reasonable for EPA to permit simple cycle CTs to operate at those levels and to expect NGCCs to operate above those levels.

Other critics may object on the ground that EPA must ensure sufficient gas-fired capacity that can dispatch so quickly (i.e., within 10 minutes) in the case of a large generating or transmission failure in the system that only CTs—and not even fast-start NGCCs—can serve this function. As discussed previously, fast-start NGCCs can, in emergency situations, bypass their HRSG and steam turbine and operate their gas turbines with a 10-minute startup time, bringing the steam components of the facility up to operational conditions afterwards. In any event, these facilities will rarely, if ever, have reason to run in this manner: as applied by grid operators, the need for 10-minute start-up capability is applicable to CTs *that will not normally operate*, but will instead sit idle in order to provide reserve capacity in the event of an emergency. These units will certainly not be operating more than 5 to 8 percent of the year in response to emergencies.

There is simply no justification for allowing simple cycle turbines to operate at capacity factors of above 5–8 percent annually and 15 percent monthly, and certainly not at annual factors exceeding 20 percent. As the data show, the vast majority of simple cycle units already run at very low frequencies, and combined cycle technology can easily accommodate all generation needs about the cut-points we recommended for low-load units. The agency must therefore designated NGCC technology as part of the "best system" for all units operating at capacity factors above those thresholds.

C. EPA Must Recalculate the Baseline Emission Reduction Rates for All Affected Combustion Turbines.

The changes to EPA's proposed combustion turbine standards that we urged in the previous sections would significantly affect the baseline (i.e., pre-CCS or hydrogen) emission rates that sources must achieve. Based on our recommendations, we have recalculated those rates, which appear in the table below. Our methodology starts by considering the "new and clean" ISO heat rates published by *Gas Turbine World.*[42] For the (newly contracted) low-load subcategory, we selected the emission rates of

[42] The International Organization for Standardization (ISO) heat rates published by *Gas Turbine World* are based on full rated output at 59°F (15°C) ambient air temperature, 14.7 psia seal level elevation, 60 percent relative humidity, no SCR, and no steam injection for load enhancement. *See* Gas Turbine World, *2022 GTW Handbook, Vol. 36*, 42 (2022). We employ EIA's published figure of

the fourth-most efficient large (>300 MW) and small (<300 MW) simple cycle combustion turbines. For the intermediate-load and baseload subcategories, we selected the heat rates of the fourth most-efficient large (>250 MW) and small (<250 MW) combined cycle units and converted those data to emission rates using standard conversion factors. These ISO rates would apply at the time of purchase,[43] thus ensuring that only the most efficient designs are employed.

Next, we compared the ISO rates for previous models with actual emissions data provided in CAMPD and concluded that turbines' in-use rates are approximately 22 percent higher than their "new and clean" rates. We thus multiplied those figures by a factor of 1.22 to establish a conservative estimate for in-use performance. We then provided an additional 4 percent performance margin for low-load and intermediate-load units and a 2 percent performance margin for baseload units. The final figures are as follows:

Table 5: Newly Calculated Baseline Performance Rates for Combustion Turbine Standards

Subcategory/unit size (MW)	ISO efficiency (percent) (net heat rate – (Btu/kWh))	ISO emission rate (lb CO_2/MWh (net))/in-use rate
Peaking units (<5–8% annual CP)		
<300 MW	41.3 (8302 [44])	970/1,280[45]
>300 MW	43.5 (7855)	920/1,210

117 lb CO_2 emitted per MMBtu of gas combusted to convert the published heat rates to emission limits.

[43] Project applicants would be required to provide vendor testing data documenting actual performance at ISO full load conditions. To the extent that EPA is concerned that differences in air pressure and temperature could benefit some sources' emission rates while disadvantaging others, it must not adjust the *entire* standard downward. Instead, the agency should implement a *unit-specific* adjustment factor for each source that accounts for temperature and pressure characteristics of the location in which it is situated.

[44] According to the *2022 GTW Handbook*, *supra* n. 42, the GE LMS 100 PA+ simple-cycle turbine is rated at 43.9 percent efficiency (7,773 Btu/kWh), which would suggest an emission limit of less than 1,050 lb/MWh (net). The GE/Baker Hughes LM 9000 claims an efficiency of "greater than 44 percent." Press Release, Baker Hughes, Baker Hughes LM9000 confirmed as world's most efficient simple cycle gas turbine after reaching key testing milestone for Arctic LNG 2 (June 9, 2020), https://www.bakerhughes.com/company/news/baker-hughes-lm9000-confirmed-worlds-most-efficient-simple-cycle-gas-turbine-after.

[45] The proposed efficiency and ISO emission rates are based on the figures published in the *2022 GTW Handbook* for the fourth best performer in the relevant size categories. The conversion from ISO ratings to emission limits is based on the emission rates accessed through a CAMPD query, with additional compliance margins of 2 and 4 percent for baseload and peaking units respectively.

Seasonal/intermediate-load units (>5–10% <40% annual CP)[46]		
<250MW	55 (6200)	725/955[47]
>250MW<500MW	60 (6000)	702/925
>500MW	63[48] (5416)	635/835
Baseload units (>40% annual CP)		
<250MW	55 (6200)	725/925
>250<500 MW	60 (6000)	702/870
>500 MW	63 (5416)	635/785

It is worth noting that we have identified an output-based CO_2 emission limit for low-load units, in contrast to EPA's proposed "clean fuel," input-based limits. The agency has expressed concern that CT emission rates are highly variable at capacity factors below around 15 percent, 88 Fed. Reg. at 33,321, concluding that the only practicable standard for such units is one based on CO_2 per unit of fuel input. Our methodology avoids this problem in three ways. First, we propose a "new and clean" ISO design standard based on the fourth-most efficient turbine design in today's market, rather than the single most efficient unit currently available or a design reflecting even greater efficiency improvements expected to occur over the next several years. Second, our 22 percent "in-use" factor—which reflects actual, historical emission rate variations—affords an additional compliance cushion that accounts for varying rates at low load. Finally, the additional 4 percent compliance allowance that low-load units receive (as do intermediate-load units) provides yet a third layer of compliance leeway. These three steps should address any concern that sources operating at low capacity factors cannot meet an output-based standard.

D. EPA Must Not Exempt New CTs Below 25 MW in Capacity from Regulation Under the Program.

EPA proposes to exempt small EGUs from the NSPS:

> To be considered an affected EGU under the current NSPS at 40 CFR part 60, subpart TTTT, the unit must meet the following applicability criteria: The unit must: (1) Be

[46] We base this 40 percent annual capacity factor cut-point separating intermediate-load from baseload units on analysis conducted by Clean Air Task Force and Natural Resources Defense Council. *See* Clean Air Task Force and Natural Resources Defense, *Comments on New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 61, 64, 69 (Aug. 8, 2023).

[47] While ISO efficiencies are similar to those for baseload units, a higher emission limit for seasonal/load-following units is provided to reflect the increased cycling effects.

[48] GE and Mitsubishi offer large NGCCs with efficiency ratings at or above 64% (<5332 Btu/kWh), which would translate to an in-use emission limit of 775 lb/MWh. *2022 GTW Handbook, supra* n. 42.

> capable of combusting more than 250 million British thermal units per hour (MMBtu/h) (260 gigajoules per hour (GJ/ h)) of heat input of fossil fuel (either alone or in combination with any other fuel); and (2) serve a generator capable of supplying more than 25 MW net to a utility distribution system (i.e., for sale to the grid).

Proposed 40 C.F.R. §60.5509a(a)(2). The agency must delete this exemption and include these units in the program. EPA has a long history of regulating numerous classes of "smaller" sources that, as a group, generate harmful emissions. These include not only cars, motorcycles, trucks and buses,[49] but also lawn mowers, weed trimmers, and ice augers.[50] A 24.9 MW CT has potential CO_2 emissions of approximately 160,000 tons per year.[51] We estimate that there are now operating nearly 1,000 CTs that qualify for EPA's exemption. We know of no economic or technical barrier that would preclude EPA from establishing a performance standard for these units to ensure that they do not operate outside of their intended peaking mode.

While many of these EGUs are stand-alone units, many others are co-located with one, two, three, or more CTs, in some cases greatly exceeding the 25 MW in the aggregate. For example, the Narrows Generating Station is a floating "power barge" located in New York's Upper Bay between Brooklyn and Staten Island. This facility consists of 16 simple-cycle turbines, each 22 MW and thus below the applicability threshold, that together amount to 352 MW[52]—equal in capacity to many combined cycle units.

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[49] *See generally* 40 C.F.R. Part 86.
[50] 73 Fed. Reg. 59,034, 59,035 (Aug. 8, 2008) ("We are adopting standards that will require manufacturers to substantially reduce emissions from marine spark-ignition engines and from nonroad spark-ignition engines below 19 kW that are generally used in lawn and garden applications.") (codified at 40 C.F.R. Part 1054).
[51] This figure assumes round-the-clock annual operation and an emission rate of approximately 1,450 lb/MWh, which is representative for CTs of this size.
[52] These data were accessed through a query to CAMPD.

Fig. 8: Photograph of Narrows Generating Station

Going forward, EPA should close this potential loophole and assure that any such co-located units are not treated differently with regard to their CO_2 emissions than otherwise identical facilities that have fewer—but larger—turbines and are thus subject to the rule's requirements. The agency must therefore (a) eliminate or dramatically lower the 25MW exclusion and (b) provide that where new small units located at units have a combined generating capacity greater than 25 MW, the performance standard for units greater than 25 MW applies.

E. EPA Must Accelerate the Compliance Deadline for Sources Using Hydrogen.

For baseload combustion turbines, the proposed rule provides two alternative BSER pathways (CCS or hydrogen) that EPA has determined can achieve equivalent performance in reducing stack emissions. However, the proposal would establish different compliance dates depending on which of the two systems a source selects. For sources that rely on CCS to meet the standards, EPA is proposing a CO_2 emissions limit of 90 CO_2/MWh-gross, with compliance starting in 2035. Proposed 40 C.F.R. Subpart TTTTa, Table 1. For sources that rely on low-GHG hydrogen co-firing, EPA is proposing an initial standard of 680 lb CO_2/MWh-gross starting in 2032, but those sources would not have to meet the CCS-equivalent 90 lb CO_2/MWh-gross standard until 2038. *Id.*

The proposal to tie compliance dates to a source's selection of a particular system of emission reduction is not consistent with EPA's obligation to prescribe standards of performance that reflect the application of "the *best* system of emission reduction." 42 U.S.C. § 7411(a)(1) (emphasis added). One could interpret EPA's proposal as determining that the "best" system for baseload turbines in 2032 is low-GHG hydrogen co-firing whereas in 2035, it is CCS. The proposed rule never truly grapples with this issue. EPA attempts explain its decision by observing that the D.C. Circuit has recognized the need for lead time to comply with certain standards of performance, and that the agency has in the past promulgated numerous standards of performance using a phased approach. *See* 88 Fed. Reg. at 33,289. Yet these examples provide no support for EPA's adoption of a standard of performance under which a regulated source can choose to wait three extra years to meet the ultimate emission limit.

To the extent that hydrogen combustion is an alternate version of the best system of emission reduction for baseload turbines, it should provide an alternative pathway to meeting the proposed 90 lb/MWh-gross standard in 2035. If EPA nonetheless finalizes the proposed staggered compliance approach, it must explain how hydrogen co-firing is equivalent to the CCS-based pathway notwithstanding that three-year compliance delay. Alternatively, if EPA insists that hydrogen co-firing along the proposed timeline represents the BSER for certain baseload gas units, then it must explain what shared characteristics of those units qualify them for their own subcategory and why, based on those characteristics, hydrogen co-firing is superior to CCS.

IV. COMMENTS ON EMISSION GUIDELINES.

In this section, we offer numerous ways in which EPA should strengthen and improve its emission guidelines for existing EGUs. Under the current proposal, existing short- and imminent-term coal units and all existing oil and gas steam units have no emission reduction obligations at all. Rather, these units are expected merely to maintain their existing (as of 2030, presumably) CO_2 emission rate with no backsliding. Yet section 111 standards are based on the best system of emission *reduction*. Even if these sources cannot achieve the level of emission mitigation expected of long-term coal units and those subject to a gas co-firing BSER, there are multiple avenues they can pursue to reduce their emission rates. In the section below, we discuss a number of those strategies, was well as additional matters pertinent to EPA's proposed emission guidelines.

A. EPA Has Not Justified Excluding Heat Rate Improvements (HRI) from its "Best System" for Existing Units.

EPA has long understood that fossil steam units and combustion turbines alike can reduce their emission performance by optimizing the rate at which they convert heat input into electrical output (known as a "heat rate"). In both the Clean Power Plan (CPP) and Affordable Clean Energy (ACE) rules, heat rate improvements, or HRI, were components of the "best system" for fossil steam EGUs: in the CPP, they were one of three "building blocks" constituting the BSER, 80 Fed. Reg. 60,4662, 64,787 (Oct. 23, 2015), whereas in ACE, they were the sole component. 84 Fed. Reg. 32,520, 32,535 (July 8, 2019). Of course, the CPP was legally voided by the Supreme Court on other grounds in *West Virginia v. EPA*, 142 S.Ct. 2587 (2022), and the agency now proposes to withdraw the ACE rule, in part on the principle that HRI *by themselves* would not provide sufficient emission reductions in comparison to other technological options. 88 Fed. Reg. at 33,337.

Joint Environmental Commenters agree entirely that CO_2 regulations for the electric power sector based solely on HRI would be inadequate. The percentage of emission reductions that could be achieved by improving the operational efficiency of fossil units would be in the single digits. This is far less than the more aggressive BSER options EPA has included in the "best system" for the Proposed Rule, and is nowhere near the level of reductions required by the applicable legal standards, much less needed to provide the kinds of climate benefits necessary in light of the sector's overall GHG emissions. A rule based on HRI measures and nothing more, as ACE was, would be arbitrary and capricious.

At the same time, EPA has not provided a compelling reason to *exclude* HRI measures altogether from its "best system" determination. In the preamble, the agency addresses this point only briefly and offers two reasons for its decision. First, it argues that HRI would provide "relatively minor overall GHG emission reductions." *Id.* at 33,357. While this is a legitimate basis for not establishing HRI as the *sole* element of the BSER, it does not mean those measures should be rejected entirely, or that sources should be given a free pass with respect to their operational efficiency.

Second, EPA asserts that the potential for what is known as the "rebound effect" is reason not to include HRI in the "best system." *Id.* Because improved efficiency reduces a source's fuel costs, it makes the unit more competitive vis-à-vis other sources, and the unit may be likely to dispatch more often. Thus, even while the source's emission *rate* improves, its *overall* emission reductions may be reduced (and possibly offset) by increased dispatch. Again, this phenomenon—while certainly plausible—does not justify excluding HRI from the "best system." Given the way EPA's rule proposal is already structured, plant operators will likely pursue compliance pathways that entail significant shifts in dispatch. For example, EPA has represented that, according to its modeling results, operators will, in some instances, choose to shift load from more tightly controlled baseload gas turbines to less tightly controlled intermediate-load sources (or to existing units that are not covered under the rule). In these cases, some sources with inferior emission rates will end up operating more than they would have in the absence of the rule.

By contrast, where HRI measures incentivize shifts in dispatch, it will *always* be from a higher-emitting to a lower-emitting unit, which will ensure net emission decreases from the affected fleet. Even while it is theoretically possible that *individual units* might end up emitting more overall CO_2 than they would have otherwise, this will already occur to a much greater degree under EPA's existing proposal. Furthermore, dispatch shifts are only like to occur where a regulation affects a unit's operational costs *relative to other units*. In theory, if *all* sources in the program must improve their operational efficiencies via HRI, then no relative changes will occur, and thus no possibility of a rebound effect. As we discuss below, as a practical matter, our proposal will likely require some sources to undergo greater improvements than others, but the fact that all units will be required to achieve their own near-optimal historical efficiencies will reduce the chance of significant incidental shifts in dispatch. And to the extent that HRI measures do result in dispatch shifts, any resulting rebound effect is likely to be entirely drowned out by the much more significant shifts resulting from sources' compliance decisions made in response to other requirements under the rule.

Moreover, in *West Virginia*, the Supreme Court indicated that the purpose of section 111 standards is to require "regulated source to operate more cleanly," 142 S. Ct. at 2596, which is exactly what HRI do. Not only would HRI improve the operating rates of individual units, they would also achieve net emission reductions across the fleet. While it is possible that some individual units might operate more than they did previously, and that those units *might* see greater overall emissions, the agency's current proposal would require *no* emission rate reductions at many classes of units, with *no* attendant fleetwide reductions. On balance, we consider it more environmentally protective, and consistent with section 111's legal standards, to require improved efficiency across-the-board, even if small dispatch shifts occur, particularly where any such shifts will be undetectable in light of the greater shifts that will result from other compliance choices under the rule.

B. The Results of Sierra Club's 105-Unit Study Demonstrate that Meaningful Emission Reductions Are Achievable by Requiring Coal-Fired Units to Maintain an Emission Rate that Reflects Their 95th Percentile Best Historical Rolling Annual Average.

Research conducted by Sierra Club indicates that an HRI element of the BSER reflecting improved operation and maintenance (O&M) practices could drive emission reductions at coal plants in excess of 7 percent on average relative to 2017 figures. This research, which we title the 105-Unit Study, consists of a review and analysis of the emissions performance of U.S. fossil fuel-fired power plants. This study included daily emissions and generation data from 2001 to 2017 of 105 coal and gas fired units—a total of over 14 million daily operation records. The study group included 51 representative coal-fired units with over 29,000 MW of generating capacity that in 2012 emitted 167 million tons of CO_2. It also included 54 representative gas-fired units with over 12,000 MW of generating capacity that emitted 25 million tons of CO_2 in that same year. Together, these study group units represent more than 5 percent of the generating capacity and approximately 8 percent of emissions from the U.S. fossil fuel-fired fleet as of the years examined. The units were chosen randomly according to a stratified sampling protocol that weighted participation toward larger units that would be expected to operate for longer periods into the future than smaller units.

Our fundamental conclusion from the 105-Unit Study is this: many EGUs currently operating in the U.S. fleet experience a wide variation in their emission rates over time. Furthermore, these variations are still apparent in an analysis of the data that effectively rules out such factors as seasonal fluctuations and the installation of new equipment requiring a large auxiliary load. Accordingly, the data indicate that these variations are the result of inconsistent O&M practices on the part of the plant owners and operators. As a logical corollary, if sources were obligated to adhere to the best O&M practices with consistency, they could reduce the variations in their emissions performance. More specifically, if all coal plants (including imminent- and near-term retiring units) were required to achieve—and, as long as they operate, maintain—their 95th percentile lowest rolling annual CO_2 emissions from the 2001–2017 timeframe, this would reflect the source's best O&M practices, and would reduce emissions across the fleet by an average of 7.4 percent relative to 2017 performance.

All of the data underlying the 105-Unit Study were accessed via queries to CAMPD, and we are providing the full study results in electronic media under a separate cover letter. Here, we summarize major takeaways of the 105-Unit Study as it relates to coal-fired units and highlight a number of specific examples to help illustrate our conclusions. (In the following subsection, we discuss the study results in the context of combustion turbines.) First, many coal units in the study showed variability in their long-term rolling annual average CO_2 emission rates that is much larger than one would expect in response to factors such as weather, seasonal variation, the installation of control equipment with a large parasitic load, or changes in electricity demand. A prime example of this is

Fayette Unit One. This unit shows both degradation in its emission rate over time as well as wide fluctuations in performance within a shorter period (such as between 2011 and 2013). These variations, which appear independent of the unit's installation of major pollution control equipment, are depicted in the charts below.

Fig. 9: Daily Average CO_2 Emissions Rates at Fayette Unit 1, 2001–2017

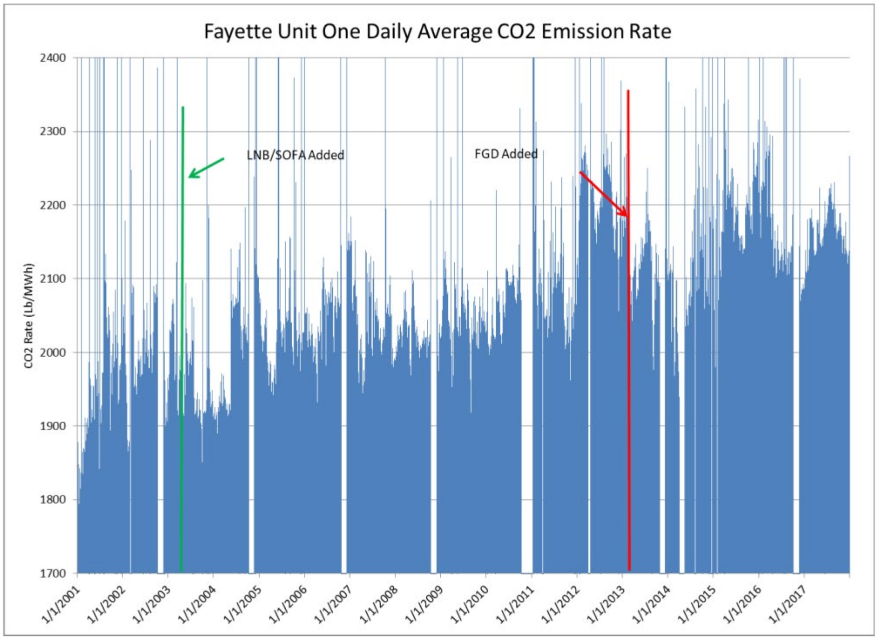
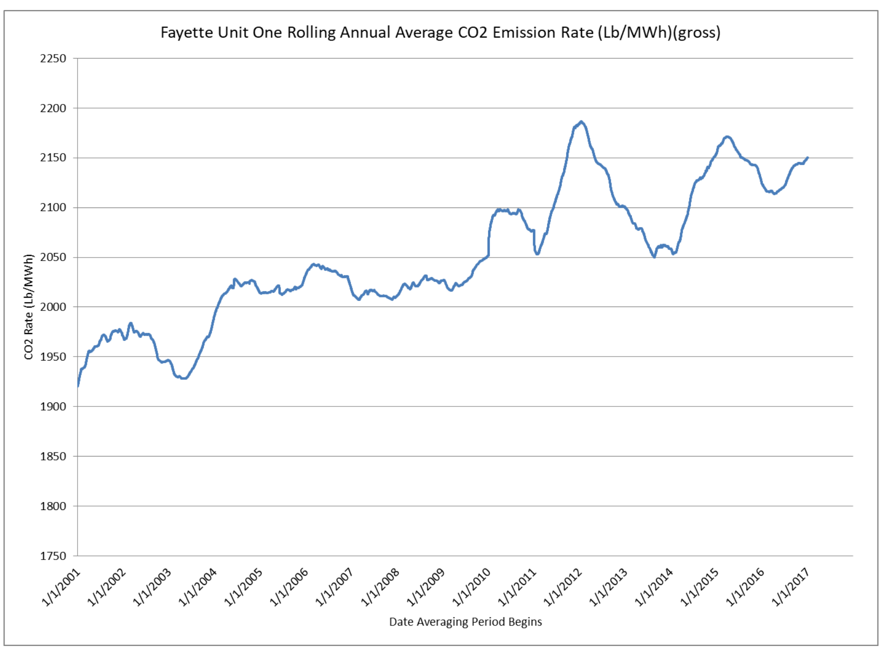


Fig. 10: Rolling Annual Average CO_2 Emissions Rates at Fayette Unit 1, 2001–2017



In addition, units differ substantially in the variability of their annual average CO_2 emission rates: some perform reasonably consistently while others show far greater fluctuation. This suggests that the cause of much of this variability is related to plant-specific factors rather than any systemic issue. In addition, some units suffer a much larger degradation in emissions performance over time than others. These facts suggest that there are meaningful differences in O&M practices both from one unit to the next, as well as inconsistent O&M practices at those units that show wide variability of emission rates over time. Craig Unit Three is a paradigmatic example of a unit with large inconsistency in its emission rates over the 17-year study period:

Fig. 11: Daily Average CO_2 Emissions Rates at Craig Unit 3, 2001–2017

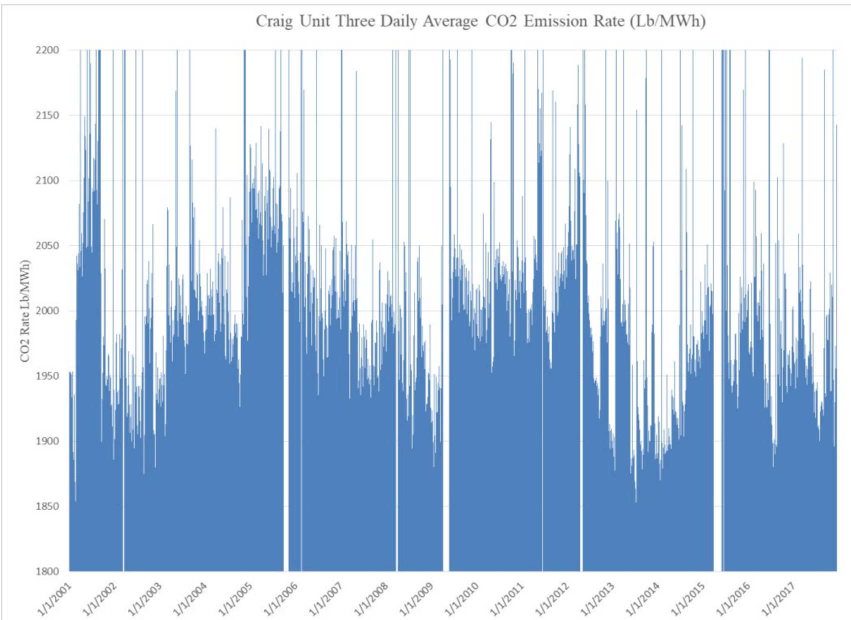
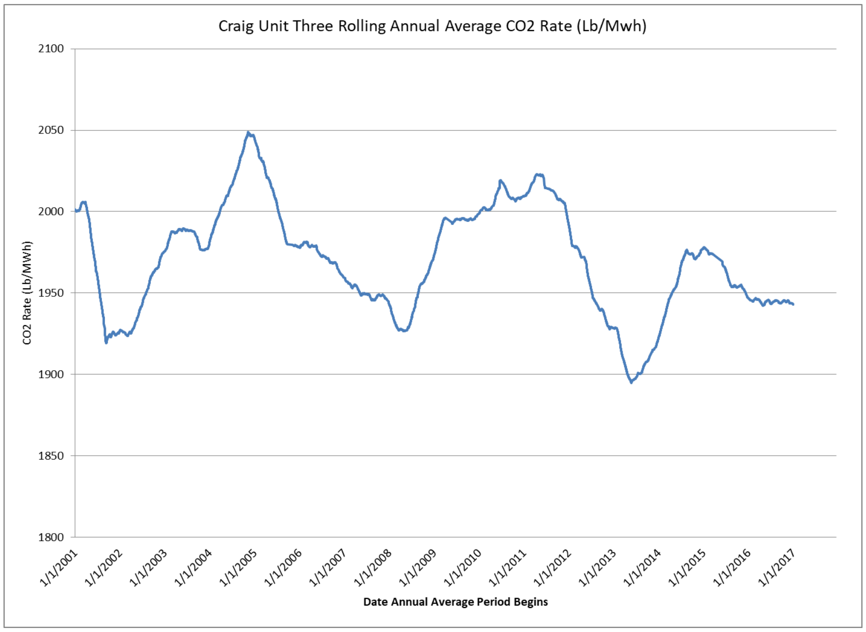


Fig. 12: Rolling Annual Average CO_2 Emissions Rates at Craig Unit 3, 2001–2017



It also appears that while load is one factor in an EGU's emission rates, much of the variability seen in the reported daily CO_2 rates at sources in the study group is unrelated to load. Indeed, the data for many units reveal major variations *within* a unit's emissions performance at full load. Furthermore, many coal-fired units operate at very low loads only infrequently, as seen in the figures below.

Fig. 13: Cardinal Unit 2 Emission Rate vs. Daily Load, 2001-2017

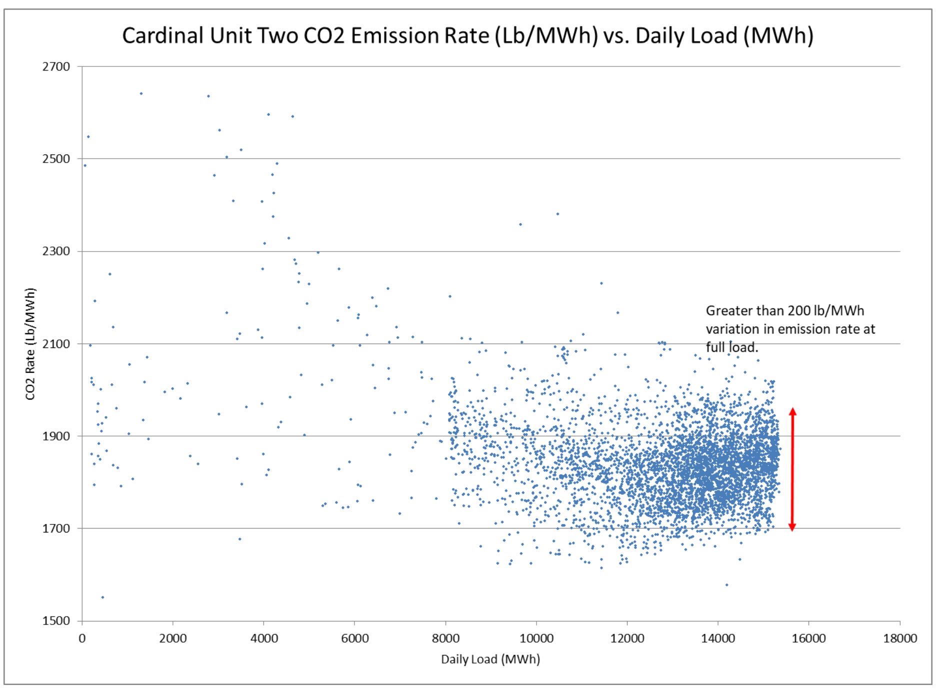
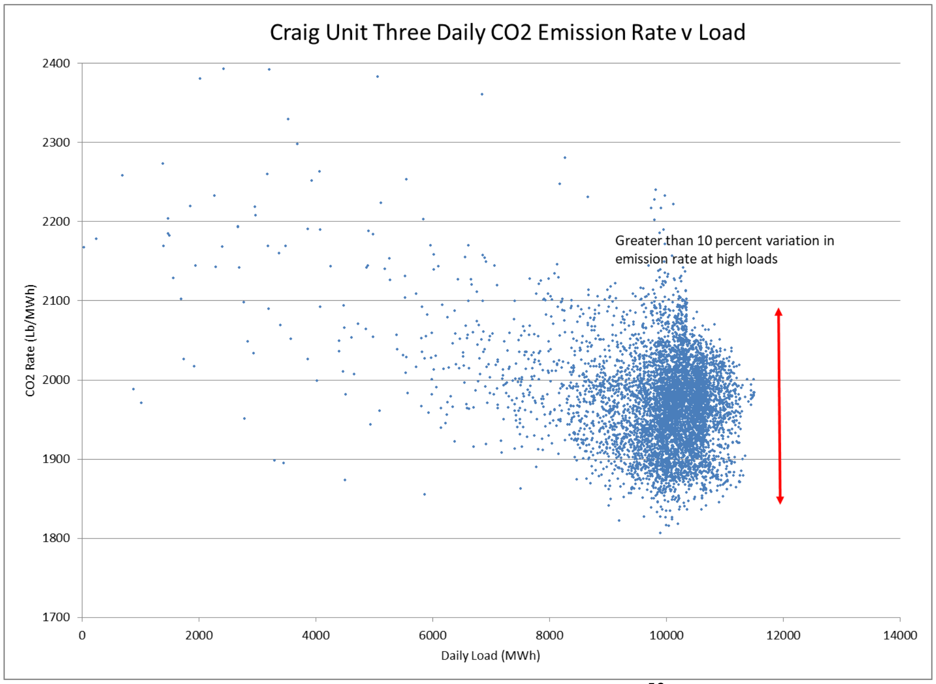


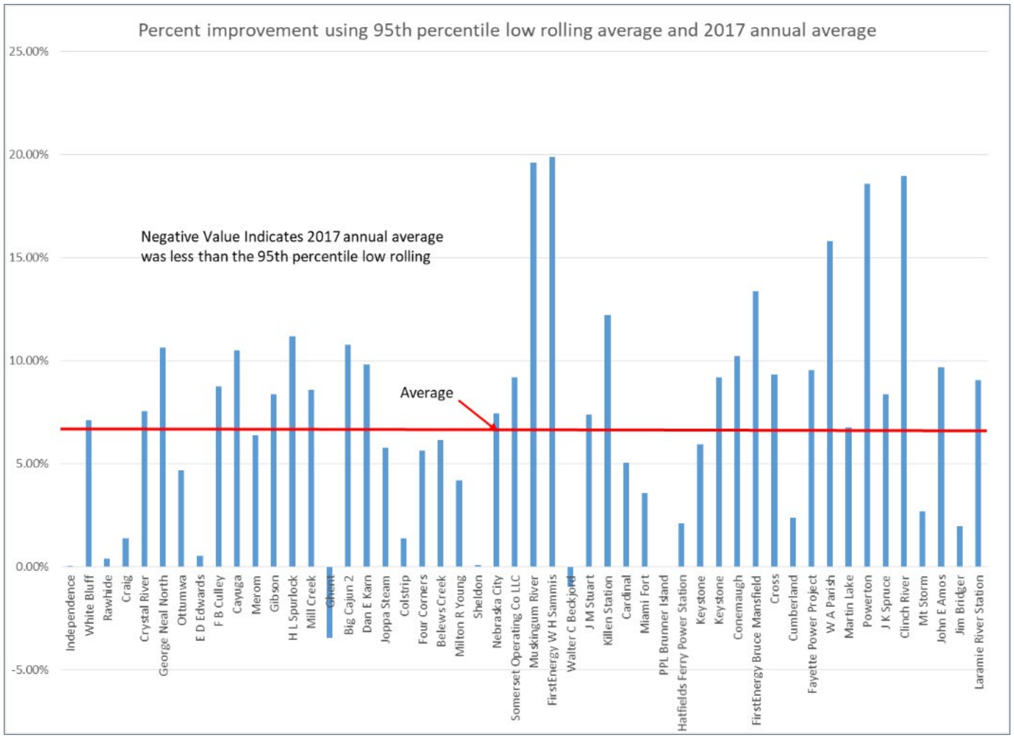
Fig. 14: Craig Unit 3 Emission Rate vs. Daily Load, 2001-2017



An earlier review, employing the NEEDs data set,[53] revealed similarly varying and large differences in year-over-year plant heat rate and CO_2 emission rates. Thus, these differences cannot be simply dismissed as CAMPD data issues. Based on an analysis of emissions variations across all coal-fired units in the study, if these EGUs were required to maintain the CO_2 emission levels that they had achieved in the recent past (i.e., between 2001 and 2017) at the 95th percentile best rolling annual average, emissions could be reduced by 7.4 percent from 2017 levels. The chart below depicts the percent emission reductions that this requirement would achieve at each coal unit in the study group relative to its 2017 calendar-year average rate.

Fig. 15: Average Improvement in Coal Plants' CO_2 Emission Rates Under Our Proposed O&M Component of the BSER

[53] EPA's "NEEDS" database contains the generation unit records used to construct the "model" plants that represent existing and planned/committed units in EPA's IPM Model. NEEDS includes basic geographic, operating, air emissions, and other data on these generating units. The worksheet for this review is provided as an attachment to these comments, which we are submitting along with the underlying data files for the 105-Unit Study.



Joint Environmental Commenters' recommended approach provides a workable means of achieving efficiency improvements (and thus emission reductions) at coal units. First, it establishes a standard that is consistent across all affected units and is mandatory, quantitative in nature, and, by definition, achievable at each covered source. Second, it avoids the problem of having to identify specifically what plant owners and operators must do to operate and maintain their units. Instead, a unit's best 95th percentile rolling annual average emissions rate serves as an effective proxy for the operator's O&M practices that allowed the unit to meet that superior rate. By achieving that rate going forward, the source must necessarily maintain those same superior O&M practices that it implemented in the past.

In this regard, our proposed HRI requirement would be easy to integrate into EPA's current proposal for existing coal plants by establishing a baseline emission rate for each source that reflects the unit's best 95th percentile rolling annual average from the previous 8–10 years. In other words, while the numerical standard itself varies from unit to unit, the required consistency of performance is uniform. For sources in the imminent-term and near-term retirement subcategories, this new baseline rate would simply be their standard of performance until retirement. For sources co-firing gas or installing CCS, state plan developers would use that figure as the starting point for applying the respective 16 percent and 88.4 percent reduction calculations to determine each unit's standard of performance.

Some critics of this approach might argue that as coal units age, they tend to experience lower annual capacity factors, which are correlated with higher emission rates. Thus, it will be difficult for an existing source to achieve on an ongoing basis its near-best rolling emission rate from the previous decade. While there is typically a decline in performance in the early years of a unit's life, the existing coal fleet is long past their "early" years. At this point, lower annual capacity factors more strongly correlate to higher emission rates at coal plants when they result from part load operations or frequent cycling—suboptimal practices from both an economic and environmental standpoint that EPA should take pains to discourage. By contrast, units that experience lower annual capacity factors because they run on a seasonal basis (but around the clock and at full load) will not see capacity factor-related increases in emission rates. Thus, capacity factor need not be a constraint on including our proposed HRI element in the "best system." And to the extent that any individual source can compellingly demonstrate why it would be impossible for it to achieve the expected rate, it can apply for a RULOF variance to account for this factor (which we describe in more detail below).

Thus far, we have discussed HRI requirements in the context of existing coal steam plants. Existing oil and gas steam EGUs were not included in the 105-Unit Study, and it is possible that these units have fewer opportunities for O&M-based emission reductions. However—particularly since the agency's modeling shows increased utilization of these sources as a result of the proposed rule—there is no reason that oil and gas steam units should not be obligated to operate at the greatest efficiencies possible by optimizing their O&M practices. But like imminent- and near-term retiring coal units, these sources have no emission reduction obligations beyond maintaining their current rate. EPA should thus evaluate the extent to which oil and gas steam EGUs can implement HRI and the feasibility of using a top 95th percentile rolling annual average figure as these source's standards of performance rather than the approach included in the current proposal.

C. Emission Guidelines for Existing Combustion Turbines Must Include an Across-the-Board HRI Requirement Reflecting Superior Operation and Maintenance.

As proposed, EPA's emission guidelines for combustion turbines only cover "the largest and most frequently operated (e.g., base load) existing combustion turbines," defined as units above 300 MW that operate at annual capacity factors above 50 percent. 88 Fed. Reg. at 33,361, 33,370. For all other existing combustion turbines, EPA is soliciting comment on potential "best system" measures to establish in a future rulemaking. *Id.* at 33,70-71. In this subsection, we discuss numerous emission reduction strategies available for existing combustion turbines, including some that would apply to sources beyond those EPA has covered in the proposed guidelines. To the extent that it can lawfully do so without delaying the rule's finalization, EPA should include these strategies in the final emission guidelines under this rulemaking. Otherwise, the agency must incorporate them into a second—and, we hope, imminent—rulemaking that establishes emission guidelines for all existing combustion turbines not covered in this proceeding. *See* 88 Fed. Reg. at 33,361 ("The EPA intends to undertake a separate rulemaking as expeditiously as practicable that addresses emissions from the remaining combustion turbines.").

In addition to coal plants, Sierra Club's 105-Unit Study evaluated the emissions performance of 54 gas-fired combustion turbines, including both simple cycle and combined cycle units. Although the variation in emission rates at these units was less than at coal plants, the study nonetheless shows that gas-fired units can achieve meaningful emission reductions through HRI. The study also reveals a concerning trend among existing gas units: while the majority of existing simple cycle CT units operate at low annual capacity factors, a significant number operate in load-following or even baseload capacities. Furthermore, in some cases, combined cycle units operated without running their HRSG units. These practices should be prohibited except in the case of emergencies; as discussed above, for both intermediate-load and baseload operations, it is far more efficient—and thus less environmentally harmful—to run NGCCs rather than CTs. As for new sources, the use of an HRSG unit should be part of the "best system" for any unit running above 5–8 percent annual and 15 percent monthly capacity factors.

The key findings of the 105-Unit Study regarding combustion turbines are as follows. First, some, but by no means all, gas-fired plants in the study show a significant fluctuation in emission rates across time. For instance, the Ackerman Unit AA-2 shows a steady increase in its emission rate amounting to almost 10 percent in performance in recent years even as its utilization *increases*.[54] This phenomenon, which is depicted in the charts below, indicates that, as with coal plants, gas plants' fluctuations in emission rates correspond to unit-specific operational practices. These inconsistencies can be reduced, and the unit's efficiency—and hence emissions performance—improved, by requiring sources to achieve and maintain an emissions rate corresponding to their near-best historical O&M practices.

Figure 16: Daily Average Emission Rates - Ackerman Unit AA-002, 2007–2017

[54] In 2017, this Ackerman unit's capacity factor was approximately 54 percent. This is higher than the 2017 capacity factors of many of the coal-fired units in the study.

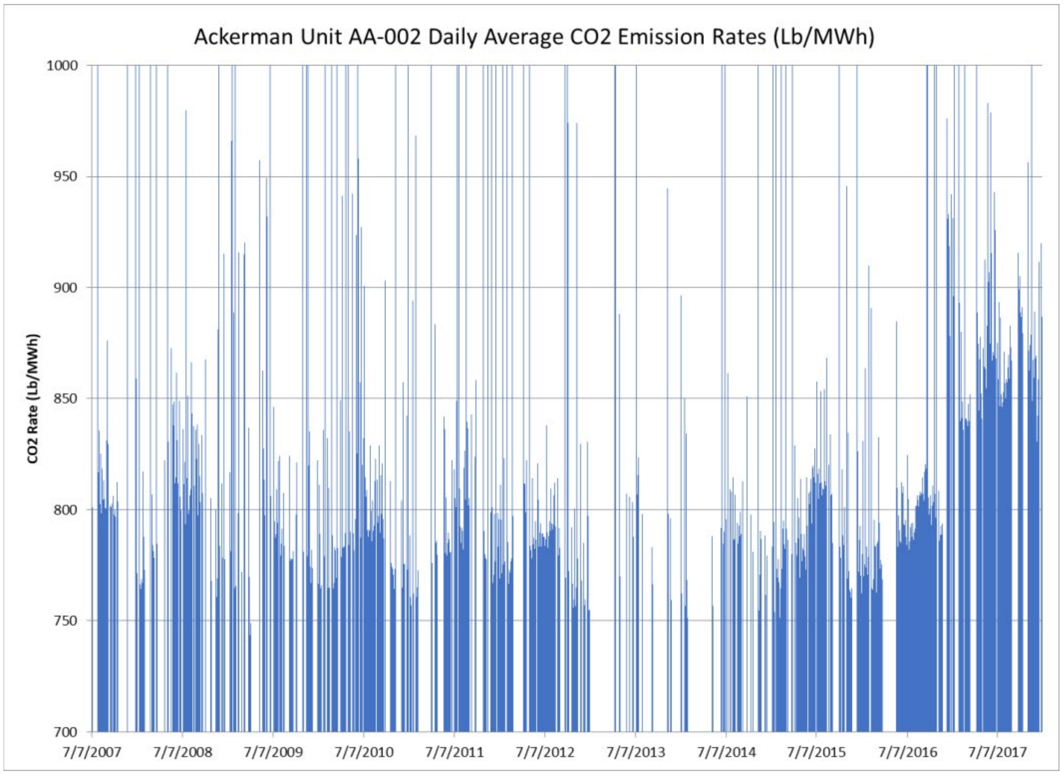
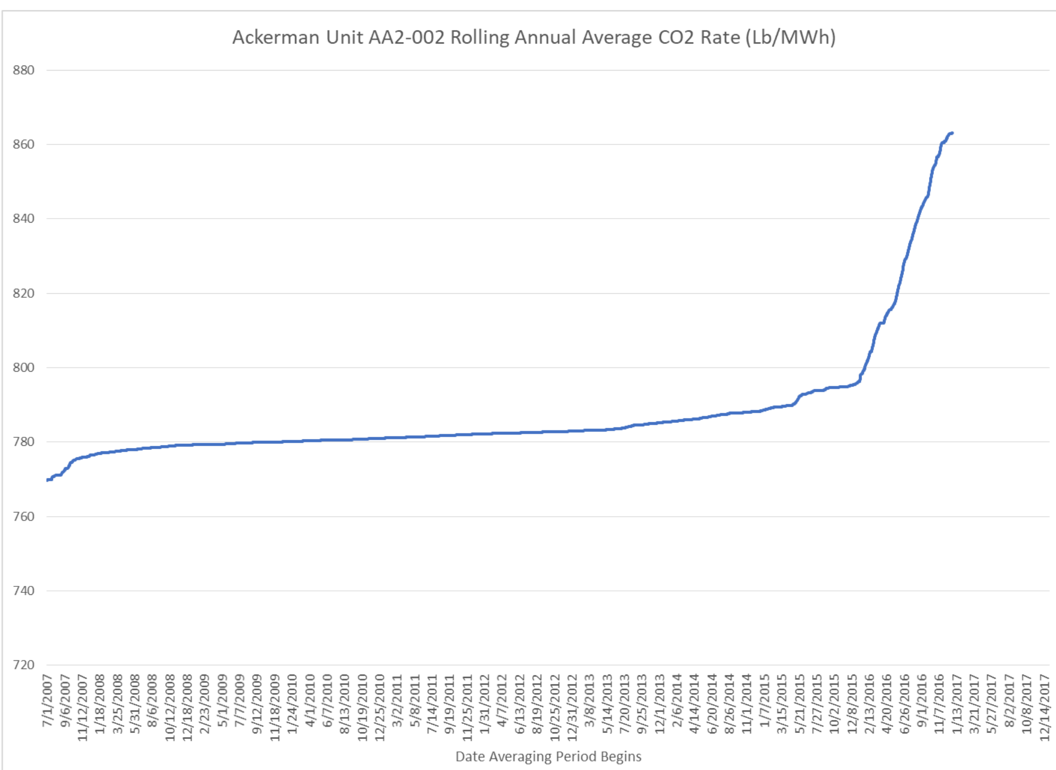
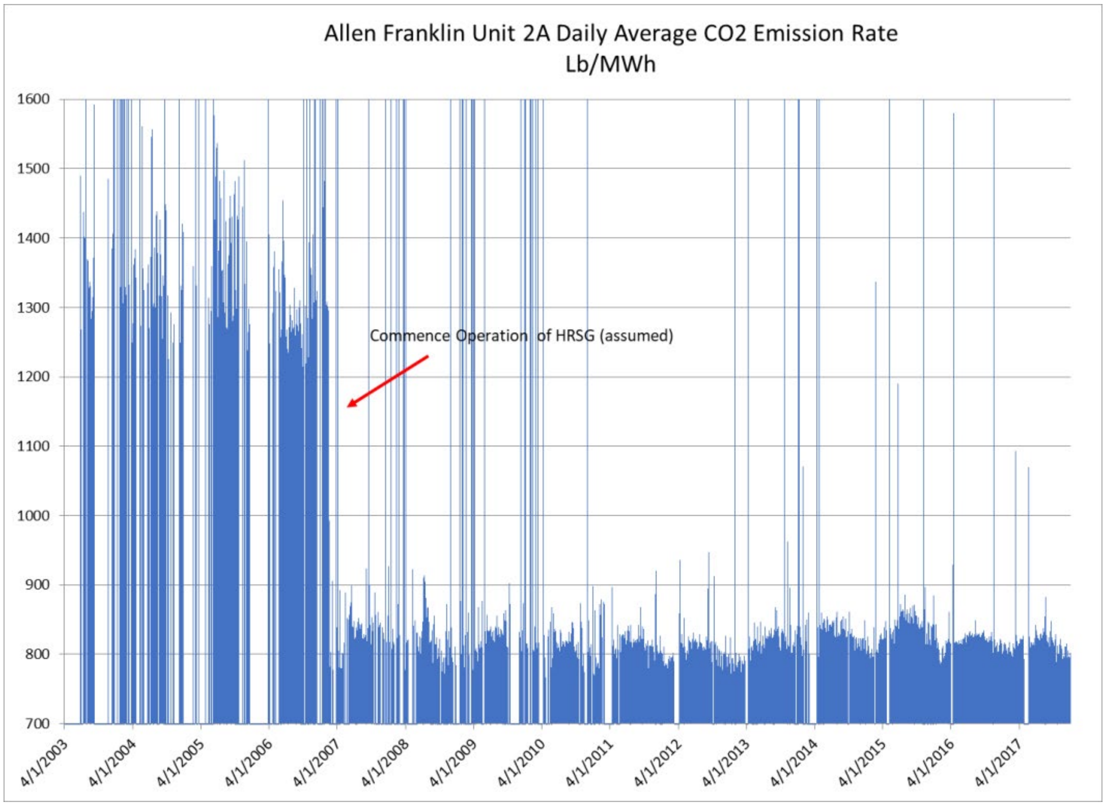


Fig. 17: Rolling Annual Average Emission Rates – Ackerman Unit AA2-002 2007-2017



Furthermore, 26 of the 54 units in the gas study group appear to have commenced operation as simple cycle combustion turbines and were subsequently retrofitted with HRSGs during the study period. This is evidenced by a significant and permanent improvement in a unit's daily average CO_2 emission rates, as depicted in the chart below for Allen Franklin Unit 2A.

Fig. 18: Daily Average CO_2 Emissions Rates -- Allen Franklin Unit 2A, 2003–2017



To ensure that the study only assessed efficiency improvements that are still available, emissions data from these units from the period prior to the apparent addition of the HRSG retrofit were excluded. Furthermore, whereas the coal unit portion of the study evaluated data from 2001 through 2017, the gas unit portion study only considered data from 2007 to 2017, so no adjustment needed to be made for units that added HRSG retrofits prior to 2007. As an example of this, the charts below depict the performance data for the aforementioned Allen Franklin Unit 2A. As seen in these charts, all data that the study evaluated for this unit post-dates the apparent installment of the unit's HRSG in early 2007.

Fig. 19: Daily Average CO_2 Emission Rate - Allen Franklin Unit 2A, 2007–2017

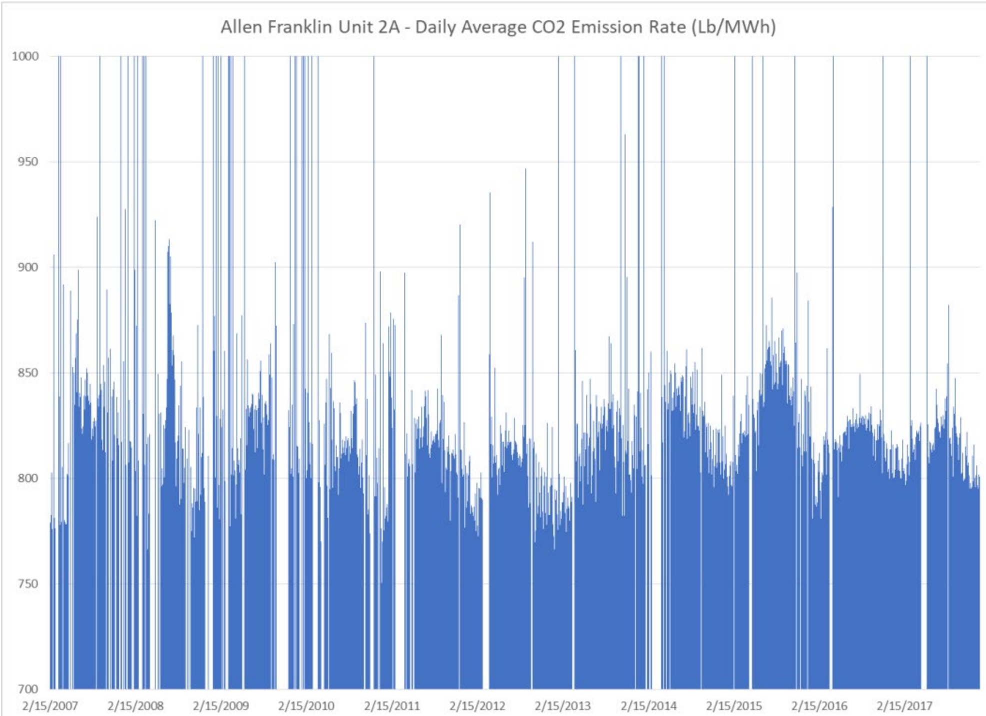
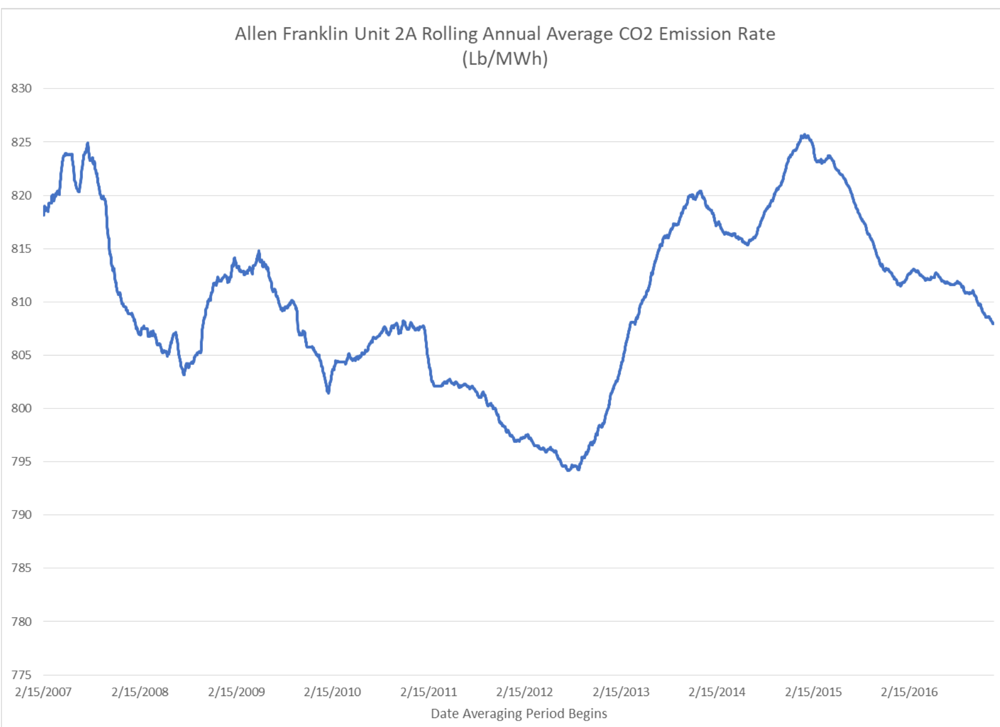
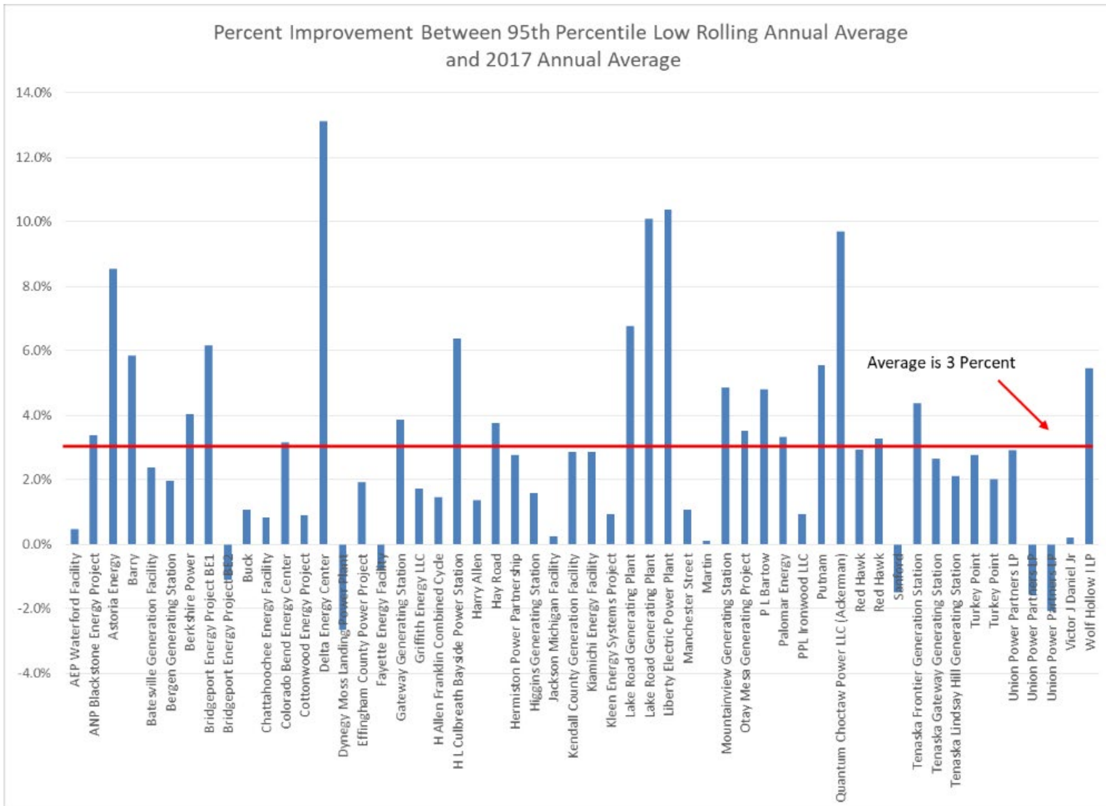


Fig. 20: Rolling Annual Average CO_2 Emission Rate - Allen Franklin Unit 2A, 2007–2017



The emissions performance of the 54 gas-fired EGUs in the study group would improve by an average of 3.03 percent relative to their 2017 calendar year performance if operators were required to consistently achieve an emissions rate corresponding to their 95th percentile lowest rolling annual average over the 2007–2017 period. The chart below depicts the percent emission reductions that would be expected at each gas-fired unit in the study group relative to its 2017 calendar-year average rate.

Fig. 21: Percent Improvement in Gas Plants' CO_2 Emission Rates 95th Percentile Low Rolling Annual Average vs. 2017 Annual Average



We therefore urge EPA to include in the BSER for existing combustion turbines the same HRI component we recommended above for existing steam EGUs.

D. EPA's Emission Guidelines for Existing Combustion Turbines Must Include a Component Requiring HRSG Retrofits for CTs Exceeding Certain Capacity Factors.

In this subsection, we discuss the option of HRSG retrofits at existing simple cycle turbines and offer and illustrative methodology for determining under what circumstances this measure should be a component of the BSER for existing gas plants. Such retrofits are technically and financially reasonable and have been voluntarily undertaken at existing facilities such as Tampa Electric's Polk Generating station.[55] If, like the proposed rule, the final Carbon Pollution Standards limit coverage of

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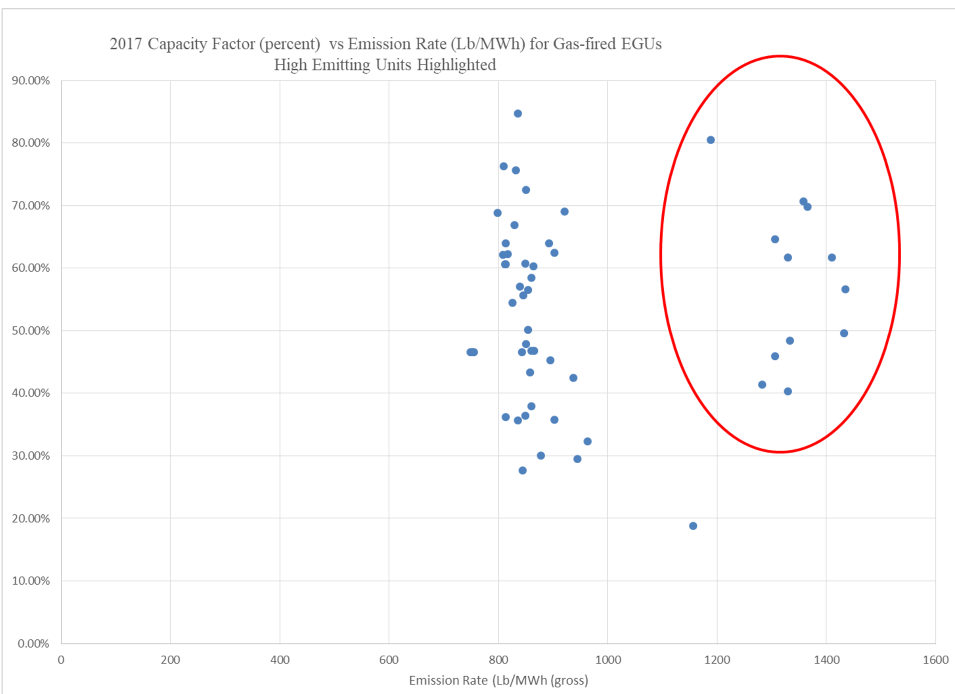
[55] Black & Veatch, *Conversion to Combined Cycle Unit Adds More Than Electricity for Tampa Electric*, https://www.bv.com/projects/conversion-combined-cycle-unit-adds-more-electricity-tampa-electric (last visited Aug. 6, 2023).

the emission guidelines for existing gas turbines to the largest and most frequently operated units, the agency should adopt our recommended approach or a similar one in a future section 111(d) rulemaking to cover the remainder of the existing gas fleet. Note that, throughout this section and these comments more broadly, we use the term "HRSG retrofit" as a shorthand for the upgrades that would be needed to convert a simple cycle turbine to a combined cycle unit, which would require adding not only the HRSG itself, but also a steam turbine and generator.

One notable finding of the 105-Unit Study was that close to one-quarter of the gas-fired units included in the analysis (13 of 54) operated through the entire study period at emission rates that correspond to simple cycle technology (i.e., ranging from approximately 1,200 to 1,600 lb/MWh). In other words, unlike units such as Allen Franklin Unit 2A described above, these plants remained simple cycle units and did not retrofit with HRSG components at any point during the study period. By contrast, the emission rates of the combined cycle units in the study ranged from approximately 800 to 1,000 lb/MWh. Furthermore, these ostensibly simple cycle units operated at relatively high capacity factors, similar to those of the combined cycle units included in the study. The chart provided below depicts this phenomenon.

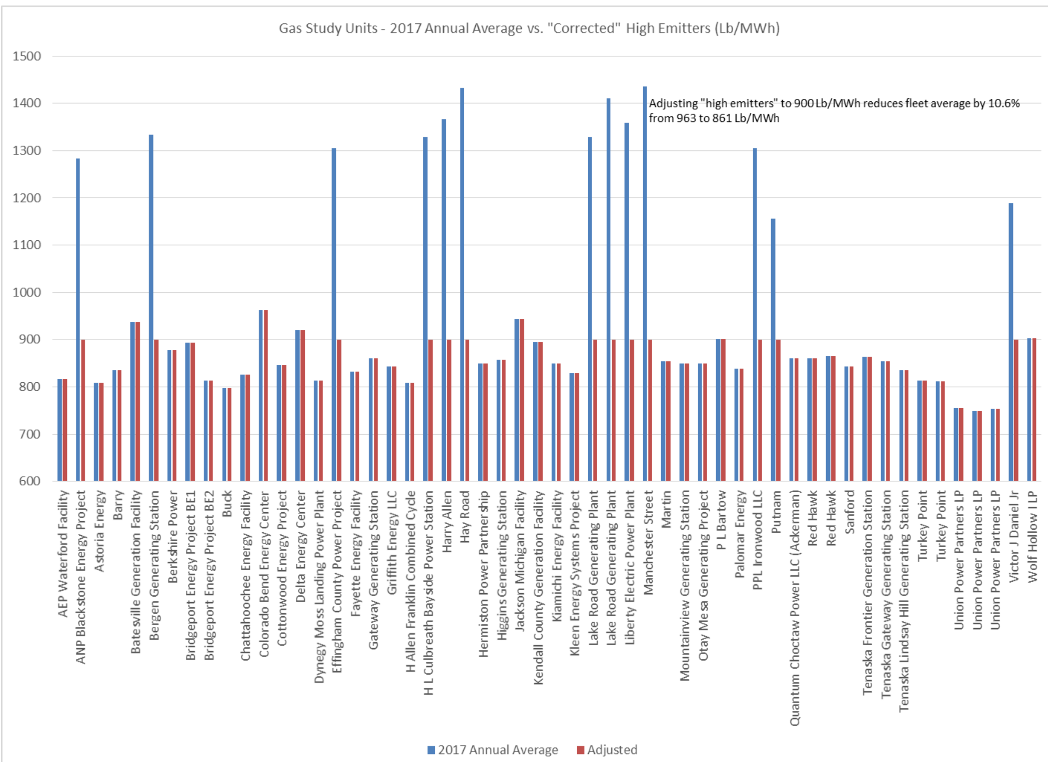
Fig. 22: Comparison of Emission Rates and Capacity Factors of Gas Units in the Study Group



These data reveal that, far from just serving peaking functions, a substantial number of existing CTs units regularly operate in intermediate-load and baseload applications. This is an environmentally unacceptable practice: on average, CTs emit approximately one-third more CO_2 per megawatt-hour (or even higher) than typical NGCCs. There is no justification for operating these units in such capacities, and, as demonstrated by facilities such as Allen Franklin Unit 2A and (we estimate) some two dozen other units in the study, it is perfectly feasible and not uncommon for CTs to install HRSG retrofits and thereby NGCCs.[56]

A "best system" measure along these lines would achieve a meaningful quantity of emission reductions. The data in the 105-Unit Study demonstrates the potential effectiveness of this measure: adjusting the CO_2 emission rates of only the 13 high-emitting units in the study group down to 900 lb/MWh—a rate that reasonably reflects the operation of an existing combined cycle unit —would reduce the study group's average 2017 fleetwide emission rate gas units by 10.6 percent (from 963 to 861 lb/MWh). The chart below depicts the results of this adjustment.

Fig. 23: Comparison of Actual vs. "Corrected" 2017 Average Emission Rates for Gas-Fired Units



EPA must prevent this excessive and unjustified operation of existing CTs by including HRSG retrofits as a "best system" element for turbines running above certain capacity factors. One potential approach would be to establish a sliding scale approach that accounts for a source's remaining useful life and sets an HRSG retrofit requirement at the capacity factor at which the social cost of the CO_2

[56] The study also identified several units equipped with HRSGs that did not employ those systems for sustained periods. This is particularly unacceptable given that the equipment has already been purchased. This problem can easily be remedied through our recommendation above: requiring sources to achieve, on an ongoing basis, an emission rate that reflects their own top 95th percentile rolling annual average.

emission reduction benefits and the savings in fuel costs would exceed the annualized costs associated with the retrofit.

To illustrate how this might work, we performed an analysis to determine at what capacity factor the climate benefits of an HRSG retrofit (through reduced CO_2 emissions) and the fuel savings it would provide would outweigh its capital costs, considering five different remaining useful life scenarios for the hypothetical unit: 5, 10, 15, 20, and 30 years. Our assumptions and methodology are as follows:

Source of cost and emission assumptions:

- Our estimates of the capital costs associated with an HRSG retrofit use (as a starting point) cost data for HRSGs and one gas turbine/generator installed at Holland Energy Park, a 2x1 NGCC unit in Holland, Michigan that came online in 2015. These data indicate that the two HRSGs cost $12.2 million and Siemens ST-400 steam turbine $8.2 million, for a combined cost of approximately $500/kW.[57]
- The following of set assumptions mirrored those from our NGCC/CT cost comparison study described in Section III:[58]
    - We used a $3.69/MMBtu cost of gas and annual interest rate of 7 percent to match EPA's assumptions.
    - For the capital recovery factor, we used Engineers Edge *Capital Recovery Formula and Calculator.*
    - CO_2 emission rates for comparably sized NGCC and CT units were based on 2021 CAMPD emission data for Bayonne Energy Center (Siemens SGT 600), Lordstown Energy Center (Siemens 600 SGT with HRSG) and Holland Energy Park, all converted to net emission rates by a factor of 1.03.
    - For the social cost of carbon, we used the federal Interagency Working Group's central estimate for 2035, which is $67/metric ton.

Methodology:

- Our study considered two hypothetical units. The first is an unretrofitted simple cycle facility comprised of two co-located and identical 67 MW CTs. The second is the same facility retrofitted with two HRSG and gas turbine/generator (and thus newly configured as a 2 x 1 NGCC), equipped with 43 MW of additional capacity.
- To estimate the capital cost of the retrofit, we started with the roughly $500/kW hardware costs reported for the two HRGs/gas turbine assembly at Holland Energy Park. We then extrapolated a range of three higher values ($800/kW, $1000/kW, and $1200/kW) to account for installation and any other costs associated with a retrofit, using 43 MW as the total capacity of the retrofit.

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[57] Power Technology, *Holland Energy Park Power Plant, Michigan*, https://www.power-technology.com/projects/holland-energy-park-power-plant-michigan/ (last visited Aug. 6, 2023). The HRSGs/steam turbine combination supply nameplate capacity of 43.2 MW according to a CAMPD query.

[58] The citations for these sources are provided in n. 32–33, *supra*.

- We then calculated the annualized costs of the retrofit (using the three $800/kW, $1000/kW, and $1200/kW price points) across five different amortization schedules to a range of different retirement scenarios for the affected unit: 5, 10, 15, 20, and 30 years.
- For each data point, we determined the capacity factor at which the fuel savings associated with the retrofit (due to increased efficiency) and the monetized climate benefits (through reduced CO_2 emissions per megawatt-hour) exceed the annualized capital costs. To provide comparable generation figures and thus allow for an apples-to-apples comparison between the retrofitted and unretrofitted units, we normalized the two facilities at 134 MW for this specific calculation.

Our calculations produced the following results:

Table 6: Break-Even Points for HRSG Retrofits

Assumed cost of HRSG retrofit ($/Kw)	Capacity factor at which climate benefits and fuel savings outweigh capital costs
30-year remaining useful life	
$800/kW	8.6%
$1000/kW	10.7%
$1200/kW	12.7%
20-year remaining useful life	
$800/kW	9.5%
$1000/kW	11.8%
$1200/kW	14.5%
15-year remaining useful life	
$800/kW	13%
$1000/kW	16%
$1200/kW	19.5%
10-year remaining useful life	
$800/kW	16.5%
$1000/kW	21%
$1200/kW	25%
remaining	
$800/kW	28.5%
$1000/kW	35.5%
$1200/kW	41.5%

Each percentage listed in the table above represents the annual capacity factor above which an existing CT should be required to install an HRSG retrofit, given the number of years left in its remaining useful life. Thus, a CT with only five years left to operate would be permitted to operate at capacity factors of up to 30 to 40 percent before the HRSG retrofit obligation applies, whereas a CT with 30 years of operational life remaining would be required to install an HRSG in order to operate at capacity factors above just 8 to 12 percent. As with the EPA's proposed emission guidelines for fossil steam EGUs, the remaining useful life windows would be incorporated into different subcategories, with each unit accepting a federally enforceable retirement date based on its subcategory. Sources in each category would then be required either to accept a capacity factor limitation in its operating permit corresponding to its subcategory or to achieve an emission rate reflecting an HRSG retrofit. Additionally, sources that could demonstrate fundamentally different circumstances from those EPA has considered (such as the physically impossibility of installing a retrofit due to space constraints) would be permitted seek a RULOF-based variance from state plan developers.

We have emphasized throughout these comments that simple cycle units should not operate at high capacity factors, given their lower efficiencies and higher emission rates. This is true not just of new units, but of existing units as well. EPA should therefore consider our proposed retrofit component of the "best system" or something similar as it considers options for reducing emissions from existing CTs not covered under the Proposed Rule.

E. Existing Steam EGUs and Combustion Turbines Must Be Subject to an Additional HRI Requirement Reflecting Equipment Upgrades.

In addition to an O&M requirement, EPA should include in the "best system" for existing units an HRI element that reflects equipment upgrades designed to improve each source's efficiency. EPA has already included in the docket for the Proposed Rule two studies on this topic. The first is Sargent & Lundy's (S&L) *Heat Rate Improvement Method Costs and Limitations Memo*, published in 2023, which evaluates 16 different equipment improvements that can be implemented at coal-fired steam EGUs.[59] The second is *Improving Heat Rate on Combined Cycle Power Plants*, prepared in 2018 for Environmental Defense Fund by Andover Technology Partners (ATP), which considers over a dozen equipment upgrades at combined cycle combustion turbines (with some measures having applicability to simple cycle turbines as well).[60]

Because EPA has both reports already in the record and is clearly aware of then, there is no need to delineate in detail each and every emission reduction measure evaluated in these studies. Overall, though, we note that these studies demonstrate that both existing steam units and combustion turbines have a plethora of opportunities to improve their heat rates—and thus their emissions performance—by installing the new and latest equipment. Most of these options, such as the installation of neural network software, intelligent soot-blowers, variable-frequency drives, and retubed or expanded condensers, are, relatively low-capital investments that can and should be required at every plant that has not already installed them. A very small number of measures—most notably, turbine blade upgrades—are capital-heavy investments that operators would need amortize over a longer period of

[59] Sargent & Lundy, *Heat Rate Improvement Method Costs and Limitations Memo*, Dkt. No. EPA-HQ-OAR-2023-0072-0018 (March 2023), https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0018/content.pdf.
[60] Andover Technology Partners, *Improving Heat Rate on Combined Cycle Power Plants*, Dkt. No. EPA-HQ-OAR-2023-0072-0050, Attachment 8 (Oct. 3, 2018), https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0050/attachment_8.pdf.

time. These measures are more appropriate for units that do not have near-term retirement dates and that will be operating over a long-enough time horizon to avoid stranding those assets.

EPA should therefore include in the final Carbon Pollution Standards a "best system" measure obligating all existing coal steam EGUs (and, where applicable, existing oil and gas steam EGUs) to undertake the low-capital equipment upgrades described in the S&L study, excepting where a particular unit has already implemented a given measure at some point in the recent past (such as the last 5 to 10 years). The same requirement should apply to all existing combined cycle combustion turbines (and, where applicable, existing simple cycle turbines) with respect to the low-capital measures described in the ATP study. The higher-capital measures described in the studies—turbine blade upgrades for steam turbines in coal units and combined cycle plants and gas turbine upgrades in both simple cycle and combined cycle plants—could be limited to units with long-enough time horizons to properly amortize those assets.

In the rule preamble, EPA discusses the S&L study briefly in an effort to explain why its current proposal does not include HRI based on capital equipment upgrades as part of its BSER designation for either category of sources. The agency's arguments are simply unpersuasive. First, EPA suggests that the emission reductions achievable through HRI measures described in S&L are not large enough to justify including them in the "best system." For instance, the agency asserts that "[m]ost HRI upgrade measures achieve reductions in heat rate of less than 1 percent," "that [d]ifferent combinations of HRI measures do not necessarily result in cumulative reductions in emission rate," and that while "the upper range of some of the HRI percentages could yield an emission rate reduction of around 5 percent . . . the reductions that the fleet could achieve on average are likely much smaller." 88 Fed. Reg. at 33,357. Yet even though each measure allows for relatively small percentage improvements and such percentages are not necessarily cumulative, there is no reason to exempt sources from having to install the best equipment currently available unless doing so would be unreasonably expensive, which the agency has notably *not* argued. Furthermore, particularly at large power plants operating at high capacity factors, even small percentage improvements in heat rate can add up to something more meaningful. Again, this does not mean that an HRI-only "best system" would be appropriate—it very much would not be—but that opportunities for comparatively small emission reductions should not be left on the table simply because they are small.

In addition, fact that the percentage reductions achievable through multiple HRI measures are not necessarily cumulative poses no barrier towards including these in the "best system." We acknowledge that it would be difficult and probably impossible to attach a single numerical emission reduction requirement to a "best system" measure based on a suite of equipment upgrades (in contrast to our proposed O&M-based HRI component, which is inherently numerical). For this reason, EPA's guidelines could require equipment upgrade obligations as a separate and additional work practice standard to be included in state plans alongside the quantitative performance standards. Under section 111(h) of the Clean Air Act, EPA may prescribe work practice standards if "the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations." 42 U.S.C. § 7411(h)(2). In the case of power plants, because it is not technologically feasible to determine the cumulative emission reductions that can be achieved by the host of equipment upgrades described in the S&L and ATP studies (or any other such measures not described in the studies), the agency can establish these as work practice requirements for states to include in their plans.

Second, EPA objects that equipment upgrades are inappropriate in the "best system" because "several HRI either have limited applicability or have already been applied at many units." 88 Fed. Reg. at 33,357. As noted above, though, EPA can easily avoid this problem by simply exempting sources from any equipment upgrade that they have already installed in the previous 5 to 10 years, or that is otherwise not applicable to that facility. In any event, section 111's RULOF provision (discussed in detail in Section X below) already offers states an avenue for providing variances to sources that can show compelling reasons for one. If a unit has already installed a piece of equipment that is part of an HRI-based work practice standard, that is certainly a reason for exempting that source from such a requirement.

Third, the agency claims that "[s]ome of the HRI measures (e.g., variable frequency drives) only impact heat rate on a net generation basis by reducing the parasitic load on the unit and would thereby not be observable for emission rates measured on a gross basis." *Id.* Indeed, this is one excellent reason why gross output-standards are inappropriate in the first place, as we explain in Section V: they cannot capture efficiency associated with a plant's reduction in parasitic load, and thus exclude actual emission reductions that benefit society. But even if EPA does retain a gross output-based standard of performance in the final rule, that would not be relevant to the equipment upgrade HRI measure we have proposed. As noted above, that requirement would be formulated as a work practice standard, which involves no numerical measurement. Thus, it is irrelevant whether a given measure improves the unit gross or net performance so long as it achieves actual, real-world emission reductions—which these equipment upgrades do.

Finally, EPA downplays the benefits of equipment-based HRI by comparing the scope of the emission reductions achievable to those provided by CCS and gas co-firing. If the agency were obligated to consider *either* HRI *or* CCS/gas co-firing "best systems," this might be a persuasive argument. The fact that no such "either/or" case exists makes it irrelevant. There is no reason EPA cannot and should not require a work practice standard based on equipment upgrades in state plans alongside other BSER elements. EPA must therefore reconsider its dismissal of HRI and include these measures in the final rule.

F. EPA Must Clarify that Each Multi-Shaft Combined Cycle Combustion Turbines Is a Single EGU.

Multi-shaft combustion turbines are combined cycle units that are configured such that a single steam turbine generates electricity from the recovered waste heat from two or more gas combustion turbines, each equipped with its own HRSG. EPA discusses these in the rule preamble, indicating that it considers multi-shaft units a single, self-contained EGU, rather than multiple, distinct co-located units. For instance, EPA refers to the Okachobee Clean Energy Center as "a large 3-on-1 combined cycle EGU." 88 Fed. Reg. at 33,323. However, the agency proposes to define an "EGU" simply as "any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (i.e., meets the applicability criteria)" without further clarification. Proposed 40 C.F.R. §60.5580a. In addition, the regulatory text the proposed emission guidelines provide that, "[c]onsistent with § 60.5775b or § 60.5780b, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU." Proposed 40 C.F.R. § 60.5860b(a)(8). The proposed new source performance standards include a nearly identical provision at 40 C.F.R.§ 60.5535a9(e). This language could be construed to mean that each multi-shaft NGCC is actually several EGUs, since it consists of multiple CT-HRSG arrangements that feed recovered steam into a single steam turbine and generator.

This interpretation is inconsistent with what EPA has indicated in the preamble, and, if adopted, could exclude certain large existing NGCCs from regulation. For example, the Sherwood H. Smith Hr. Energy Complex includes a 2x1 NGCC, comprised of two 199.4 MW combustion turbines and one 195.5 MW steam turbine.[61] Considered as a single unit, this facility is a 594.3 MW EGU—nearly twice the capacity threshold for regulation under EPA's proposed emission guidelines for existing combustion turbines. Yet if each individual gas turbine is considered a single unit, with the capacity of the steam turbine apportioned evenly between them, then they are two 297 MW units, falling below the proposed regulatory threshold. The same issue would occur for a new 3x1 99 MW NGCC where the gas and steam turbines are each less than 25 MW. EPA must therefore clarify that a multi-shaft NGCC is considered a single EGU for the purposes of the Proposed Rule.

G. EPA Should Include Fuel Pretreatment and Selection as an Element of the "Best System" for Existing Coal Plants.

Many operators of coal-fired power plants neither apply fuel pretreatment methods nor use higher-rank coal (which inherently generates less CO_2 when burned compared to lower-rank coals). For example, sources can reduce their emissions of CO_2 by drying lignite using waste heat or renewable energy prior to firing it, employing coal beneficiation processes to remove mineral impurities, and blending higher-rank coal in with lower-rank coal – or for that matter, simply employing higher-rank coals. In addition to HRI through O&M improvements and, for longer-term units, capital-intensive equipment upgrades, fuel pretreatment, and the use of higher-rank coal can help reduce a coal plant's end-of-stack emission rates, and should be an element of the BSER. Thus far, EPA has not attempted to evaluate or quantify the opportunities for emission reductions through fuel pretreatment and use of higher-rank coal.

Based on information that currently exists, we can estimate the range of emission reductions achievable through the use of higher rank coal at coal plants. For example, EIA data indicate that the state-wide average CO_2 emission rate per MMBtu of heat content in coal ranges from 211 to 220 lb CO_2/MMBtu for lignite (with an average 216 lb CO_2/MMBtu), from 207 to 214 lb CO_2/MMBtu for sub-bituminous coal (with an average 212 lb CO_2/MMBtu), and 202-210 lb CO_2/MMBtu for bituminous coal (average 205 lb CO_2/MMBtu).[62] Larger differences exist in the CO_2 emissions rates of coal from individual mines. Based on these figures, using 207 lb CO_2/MMBtu coal instead of 214 lb CO_2/MMBtu coal would yield a 3.5 percent reduction in the CO_2 emission rate. These fuels, whether they are 207 or 214 CO_2/MMBtu coals, are normally purchased from offsite locations. By drying lignite with waste heat or renewable energy, operators can reduce the CO_2 emission rate by up

[61] These data were accessed through a CAMPD query.
[62] EIA, *Carbon Dioxide Emission Factors for Coal*, https://www.eia.gov/coal/production/quarterly/co2_article/co2.html (last visited Aug. 2, 2023).

to five percent.[63] These options should therefore be considered an essential component of BSER for lignite-fired units. While lignite drying would ordinarily occur at the regulated facility, using fuel that has been dried offsite (like using emission control equipment that has been manufactured offsite) is nonetheless a measure that a facility operator can employ to reduce stack emissions from an individual unit.

V. EPA MUST FORMULATE ITS EMISSION GUIDELINES AND STANDARDS OF PERFORMANCE SOLELY IN TERMS OF NET ENERGY OUTPUT, NOT GROSS ENERGY OUTPUT.

In the Proposed Rule, EPA's guidelines for existing sources express emission reduction requirements in terms of units' gross energy output—which refers to the total electricity produced by the unit's generator—rather than net energy output—which refers to the total electricity the unit delivers for sale to the grid. Proposed 40 C.F.R. § 60.5775b(c)(1)–(13). The agency's proposed standards of performance for new combustion allow units to comply either through net output-based standards or gross output-based standards. Proposed 40 C.F.R. § 60, subpart TTTTa. Table 1. Joint Environmental Commenters strongly urge EPA to abandon any adherence to gross output-based standards and instead formulate its guidelines and standards solely in terms of net electric output.

Net standards reflect the environmentally relevant consideration of how much pollution a unit emits for every unit of electricity it provides to society. Because gross standards only reflect the amount of electricity the unit's generator produces, rather than what it actually delivers to the grid, it cannot capture energy usage through that occurs between the point that the electricity is generated and the point that it leaves the facility for sale. This is inconsistent with the function of these regulations, and nothing in the Clean Air Act requires EPA to establish gross output-based emission limits. Indeed, EPA itself "recognize[s] the superior environmental benefit of minimizing auxiliary/parasitic loads"—which can only be captured by net-based standards—and has thus decided to offer an "optional" net standard for new combustion turbines alongside the primary gross standards. 88 Fed. Reg. at 33,319. In previous rulemakings, EPA provided more detail on these benefits, explaining that net standards help prioritize "(1) EGU designs and control equipment that use less auxiliary power; (2) fuels that require less emissions control equipment; and (3) higher efficiency motors, pumps, and fans." 80 Fed. Reg. 64,510, 64,535 (Oct. 23, 2015).

Yet an optional net-based standard is insufficient. Because—as EPA acknowledges—net standards offer "superior environmental benefits" by holding sources accountable for internal energy losses and large parasitic loads, then it would logically follow that most or all sources will decline to adopt that tougher option and will instead select gross standards, which ignore parasitic load and energy loss. This is particularly true given that sources may only pursue the optional net based compliance pathway through a formal petition process. 40 C.F.R. §60.5520a(c). This approach is backward: the entire purpose of the Carbon Pollution Standards is to provide "environmental benefits." If net output-based standards are feasible to implement as optional requirements, and do provide "superior environmental benefits, "there is no reason they should not be mandatory for all units.

[63] Halina Pawlak-Kruczek, et al., *Potential and methods for increasing the flexibility and efficiency of the lignite fired power unit, using integrated lignite drying*, 18 ENERGY 1142–1151 (Aug. 15, 2019), https://www.sciencedirect.com/science/article/abs/pii/S0360544219311491?via%3Dihub.

To make matters worse, EPA has not even provided a net-based option in its emission guidelines for existing steam EGUs and combustion turbines. For these units, EPA has directed states to implement gross standards with no other compliance pathway. Paradoxically, these are precisely the units with the largest potential auxiliary loads, for which basing an emission standard on gross electric output results in the *greatest* difference. In the preamble, EPA notes an example of a roughly 500 MW coal-fired steam EGU for which the CCS equipment itself would require a 23 percent auxiliary load. 88 Fed. Reg. at 33,349. This creates a greater difference between net- and gross-based standards and potentially runs the risk of misleading the public as to the expected environmental benefits under the rule.

Nowhere in the preamble does EPA adequately explain *why* it has selected gross output-based standards. The only justification EPA offers is that "[m]ost emissions data are available on a gross output basis and the EPA is proposing output-based standards based on gross output." *Id.* Yet the fact that EPA has provided optional net-based standards for new combustion turbines shows that data available for net output is not a significant problem. In any event, how the data are *currently* reported says nothing about what EPA can require *going forward*; it is no more difficult for a source to report the amount of electricity it sells to the grid rather than the electricity its generator produces in any given time frame. Similarly, EPA has developed protocols for assigning generation and emissions between regulated and unregulated emission units serving a common generator. (As noted above, though, a multi-shaft NGCC should be clearly defined as a single, regulated EGU.)

Indeed, the rule's applicability provisions are already based in part on net electrical output. For instance, a source is exempt from the requirements if its "annual *net*-electric sales have never exceeded one-third of its potential electric output or 219,000 megawatt-hour (MWh)." Proposed 40 C.F.R. §§ 60.5509a(b)(1), 60.5850b(d) (emphasis added). Similarly, whether a new combustion turbine falls into the intermediate-load or baseload subcategories depends on whether or not it "[s]upplies more than its design efficiency times its potential electric output as *net* electric sales on both a 12-operating month and a 3-year rolling average basis." Proposed 40 C.F.R. § 60, subpart TTTTa. Table 1. For EPA to use net output to determine *whether* a unit is subject to the rule and *what* that unit's standard should be, but then use gross output for the actual standard, defies logic. The rational decision would be for EPA to use net electric output for *all* determinations under the Carbon Pollution Standards, including the emission reduction standards themselves.

Moreover, net output is a clearer metric than gross output and less subject to manipulation. The latter simply refers to electricity delivered for sale—an unambiguous data point—while the former may include or exclude certain important factors. For instance, EPA has in the past employed several different definitions of "gross output" or "gross energy output." The currently applicable criteria pollutant NSPS for steam EGUs defines "gross energy output" for units built or modified *before* May 4, 2011, as

> the gross electrical or mechanical output from the affected facility plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process);

40 C.F.R. § 60.41Da. For units constructed or modified *after* May 11, "gross energy output" means

> the gross electrical or mechanical output from the affected facility *minus any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor)* plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process);

Id. (emphasis added). And for combined heat and power units, this term refers to

> the gross electrical or mechanical output from the affected facility *divided by 0.95 minus any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor)* plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (i.e., steam delivered to an industrial process);

Id. (emphasis added). These are three significantly different variations of the term "gross energy output," reflecting targeted policy choices rather than actual, straightforward measurements of electricity. The 2015 CO_2 standards for new electric generating units showed further variations still. That regulation defines "gross energy output" for IGCC units as

> the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output,

apparently without the exclusion for electricity to power feedwater pumps or gas expanders. 40 C.F.R. § 60.5580. And yet, for non-IGCC steam EGUs, the same regulation defines "gross energy output" as "the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) *minus any electricity used to power the feedwater pump*s plus 100 percent of the useful thermal output." *Id.* (emphasis added).

None of these formulations of "gross energy output" are based solely on electric generation, since they include mechanical and thermal output. Nor are they purely "gross" or purely "net" output calculations, since some aspects of parasitic load are accounted for while others are not: in several definitions above, electricity to power feedwater pumps is subtracted from gross generation, but the electricity to power pollution controls such as the FGD, SCR, or CO_2 separation equipment are not subtracted. For EPA to adopt a net output-based regulatory approach more broadly would not only provide superior environmental outcomes by encouraging sources to minimize parasitic and auxiliary loads, but would also help provide greater consistency across different regulated sources.

At different points, EPA has offered several rationales for its decision to use these various forms of gross output. In one instance, it asserted that source owners complained that a net-based standard would penalize units for installing pollution controls, which use some auxiliary load, in comparison that units that have not installed those controls. 80 Fed. Reg. at 64536. EPA also asserted that some source owners claimed that certain site-specific variations in factors such as cooling water availability and elevation militate against net-based standards. *Id.* The agency has also claimed that predicting the net electricity generation at certain units (such as IGCC facilities or those equipped with CCS) would be more challenging to implement under these circumstances because it would be difficult to predict at the outset how large their auxiliary loads might be. *Id.* Finally, EPA has pointed to

> the monitoring difficulties inherent in the net output methodology. In particular, measuring net output at facilities with both affected and nonaffected units could be problematic, because a single meter on the electricity leaving the facility could not effectively allocate the electricity leaving the affected boiler.

63 Fed. Reg. 49,442, 49,448 (Sept. 16, 1998). None of these arguments is compelling. Notably, the agency has not reproduced them in this preamble to the Proposed Rule. As for penalties based on pollution controls, EPA's emission guidelines specify a percentage reduction of each unit's baseline emission rate (or maintenance of that rate); therefore, there is no penalty associated with a pollution control already installed. Of course, any unit installing CCS because of Carbon Pollution Standards would need a significant auxiliary load to power those controls, but EPA can and should set a net-based standard that reflects a reasonable—and not excessive—auxiliary load. The agency has available to it sufficient data to determine such a reasonable load; perfect powers of prediction are unnecessary.

As for new combustion turbines, these units will be newly constructed, and so each will be subject to the same pollution control requirements as other similarly situated units. In any event, EPA has already provided alternate net-based standards for these sources, which indicates that such standards are implementable and can fully displace gross-based standards. As for source-specific variations reflecting factors such as elevation and water availability, these would be unlikely to have the kinds of large impacts that might justify gross-based standards. To the extent that any such considerations result in fundamentally different circumstances at existing units, states will have the opportunity to provide variances if the appropriate, delineated factors are demonstrated.

In short, there are no justifiable barriers toward EPA shifting its regulatory preference for gross output-based standards to net output-based standards. The agency must therefore select the environmentally preferential option of net-based emission limits in the final Carbon Pollution Standards.

VI. EPA AND OTHER FEDERAL AGENCIES MUST CLOSE REGULATORY GAPS AND ENSURE THE SAFETY AND SECURITY OF CO_2 PIPELINES AND SEQUESTRATION SITES.

EPA's Proposed Rule is premised in significant part on operators' capturing large quantities of CO_2 from their plants' flue gas and directing it to transmission pipelines for ultimate sequestration or some other use. Yet if these pipelines and sequestration sites do not operate properly, it would not only jeopardize the emission reductions that the rule might achieve, but would pose serious safety and health risks to communities in close proximity to that infrastructure. We recognize EPA will not issue standards for CO_2 pipelines and sequestration sites in this rulemaking, and that the Department of Transportation's Pipelines and Hazardous Materials Safety Administration (PHMSA) oversees pipeline safety. However, the regulatory framework for carbon pipelines and sequestration sites is deeply connected to the foundation of EPA's proposal, and closing regulatory gaps, strengthening protections, and avoiding harmful and unlawful grants of primary enforcement authority are critical to the success of this rule and to protecting the communities living near plants, pipelines, and storage sites. EPA and the other federal agencies must take swift action, in parallel with this rulemaking, to put robust pipeline and sequestration site regulations in place.

Because CO_2 is often transported in a liquid or supercritical state to facilitate flow, it must be placed under extremely high pressure in order to move through pipelines. A breach in the pipeline material will expose these contents to atmospheric pressure, and the barometric differential causes a huge explosion, with potentially devastating impacts for anyone in the vicinity: "A [CO_2 pipeline] rupture can open up a pipeline like a zipper, creating a gash that is miles long. Oxygen levels drop, temperatures plummet to below freezing, and CO_2 rolls out by the ton. Dry ice forms around the site of the explosion, which as it sublimates, sends fresh infusions of carbon dioxide to low-lying areas. A gas leak is no fun to be around, but at least it disperses quickly in open air. A cloud of CO_2 … can linger for hours."[64] And while pipelines transporting gaseous CO_2 operate at lower pressures than those carrying liquid or supercritical CO_2, leaks and breaches in these pipelines can still present safety concerns. Furthermore, releases of CO_2 from any kind of pipeline send that gas back to the atmosphere, defeating the purpose of a carbon capture requirement.

PHMSA currently oversees the construction, operation, and maintenance of CO_2 pipelines under 49 C.F.R. § 195. However, these regulations were designed to cover pipelines carrying hazardous hydrocarbon liquids and do not address some of the risks specific to CO_2 pipelines.[65] For instance, they do not set standards on impurities in the CO_2 stream, which can corrode the pipeline and present a risk of toxic releases. Furthermore, the current regulations do not require odorizers to be added to the gas stream to allow people to know when a leak has occurred, and do not address the fact that CO_2—a heavier-than-air asphyxiant—can, when released, travel further and remain in the air longer than any other compounds that are transported by pipeline.

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[64] Heather Smith, *Who's Afraid of a Carbon Capture Pipeline? Lots of People, Actually*, SIERRA MAGAZINE (Julyu 3, 2022), https://www.sierraclub.org/sierra/who-s-afraid-carbon-capture-pipeline-co2-ccs.

[65] This issue is discussed in more detail in the following white paper prepared for the Pipeline Safety Trust: Richard B. Kuprewicz, *Accufacts' Perspectives on the State of Federal Carbon Dioxide Transmission Pipeline Safety Regulations as it Relates to Carbon Capture, Utilization, and Sequestration within the U.S.* (2022), https://pstrust.org/wp-content/uploads/2022/03/3-23-22-Final-Accufacts-CO2-Pipeline-Report2.pdf, included as Exhibit 10; *see also* Kara Holsopple, *Safety Advocate Warns of Lack of Oversight for New CO_2 Pipelines Needed for Carbon Capture*, THE ALLEGHENY FRONT (Apr. 29, 2022), https://www.alleghenyfront.org/safety-advocate-warns-of-a-lack-of-oversight-for-new-co2-pipelines-needed-for-carbon-capture/ (interview with Pipeline Safety Trust Executive Director Bill Caram).

PHMSA's current regulations also only cover supercritical CO_2 and thus have no bearing on pipelines that carry subcritical liquid or gaseous CO_2. Yet the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 granted PHMSA broad authority to regulate the transportation of *all* phases of CO_2, providing that "[t]he Secretary shall regulate carbon dioxide transported by a hazardous liquid pipeline facility" and "shall prescribe standards related to hazardous liquid to ensure the safe transportation of carbon dioxide by such a facility." 49 U.S.C. § 60102(i)(1). Over a decade later, PHMSA still has not fulfilled this directive with respect to subcritical liquid or gaseous CO_2.

PHMSA has indicated that it will propose more comprehensive and detailed safety regulations for CO_2 pipelines in 2024, and it must use that opportunity to fully address these and other concerns pertaining to this infrastructure. In the meantime, numerous environmental organizations have urged the Administration to act now to ensure that its existing standards for supercritical CO_2 pipelines apply equally to liquid and gaseous CO_2 lines. As PHMSA itself concluded in a 2016 report,[66] it could extend the safety regulations currently applicable to supercritical CO_2 pipelines to those carrying other phases of CO_2 with only minor modifications. PHMSA must undertake this action immediately and prepare maximally protective safety provisions for all classes of CO_2 pipelines in its forthcoming comprehensive standards.

As for sequestration sites, EPA currently regulates these facilities only under subpart RR of the Clean Air Act's Greenhouse Gas Reporting Program, 40 C.F.R. Part 98, Subpart RR, and through its Safe Drinking Water Act (SDWA) permitting requirements for Class VI injection wells. 40 C.F.R. Part 146, Subpart H. Yet neither of these regulations is designed to prevent CO_2 leaks into the air, or to address what happens if and when such a leak occurs. The Reporting Rule requirements—while critical—are an accounting tool that do not require facilities to prevent leaks or take responsibility for them after the fact. The Class VI permitting requirements, for their part, are designed to prevent water rather than air releases, and while they may provide some protection against atmospheric leaks, they were not designed to address those concerns, given that they are Safe Drinking Water Act rather than Clean Air Act regulations. For example, while Class VI well permitting provisions include bonding requirements, these financial assurances cover plugging, site closure and remediation, and corrective action or emergency responses to CO_2 releases affecting water quality, 40 C.F.R. § 146.85(a)(2); there is no requirement that the funds be sufficient to address atmospheric releases.

The Class VI wells are the newest ones covered in EPA's Underground Injection Control (UIC) program, and the agency has acknowledged that CO_2 injection for sequestration presents unique challenges compared to other kinds of sites regulated under the UIC.[67] Only two of the facilities that EPA has permitted as Class VI wells have actually injected CO_2, and neither of the two states with Class VI primacy have operational Class VI wells. However, several states, including those with weak monitoring and enforcement track records, are pursuing primacy. For example, Louisiana has

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[66] PHMSA, Office of Pipeline Safety, *Background for Regulating the Transportation of Carbon Dioxide in a Gaseous State—Pipeline Safety, Regulatory Certainty, And Job Creation Act of 2011, Section 15* (Feb. 2015), https://www.regulations.gov/document/PHMSA-2016-0049-0001, include as Exhibit 11.

[67] *See Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2),* 75 Fed. Reg. 77,230, 77,234–35 (Dec. 10, 2010) (describing the "the unique risks to [underground sources of drinking water] associated with [geologic sequestration]").

filed an application for primacy, which EPA proposes to approve.[68] Given the myriad health, safety and climate risks that sequestration presents, EPA must scrutinize whether states can actually implement the Class VI program within the confines of the law and consistent with public safety and environmental justice. In the case of Louisiana, the answer is no.[69]

Using the full extent of their existing legal authority, EPA and any other agency with overlapping jurisdiction over geologic sequestration of CO_2 must address the regulatory gaps that currently exist for these facilities and ensure robust oversight. EPA and/or other agencies must issue regulations that, to the greatest extent possible, prevent against atmospheric releases of CO_2; must require financial sureties to cover the necessary response and remediation for such releases; and must clarify liabilities in the event that such release do occur. It is vital that the Biden Administration pursue all the tools available to it to ensure that any CO_2 that is sequestered at these sites remains sequestered, and that appropriate measures are in place to address any leaks that occur.

VII. ISSUES RELATING TO HYDROGEN.

EPA seeks comment on: (1) whether it is necessary to provide a definition of "low-GHG hydrogen" within this rule; and (2) the substance of the definition included in the proposed rule. 88 Fed. Reg. at 33,311. If EPA includes hydrogen co-firing as an element of the BSER for one or more subcategories of sources, it can and must provide a definition of low-GHG hydrogen. Today, nearly all hydrogen is produced using unabated fossil fuels.[70] In 2021, 94 million tons of hydrogen were produced globally, with associated emissions of more than 900 $MtCO_2$.[71] In the United States, nearly all commercially produced hydrogen is manufactured using the energy intensive, fossil fuel-based steam-methane reforming process, which results in substantial emissions of CO_2. While combustion of hydrogen in electric generating units reduces carbon emissions at the power plant stack as compared to combustion of fossil fuels like coal and fossil methane, those reductions will be offset by increased upstream emissions without appropriate protective guardrails like the proposed rule's low-GHG hydrogen definition. In order to avoid the perverse outcome of an overall increase in climate-changing greenhouse gas pollution, EPA must include a definition of low-GHG hydrogen in this rule.

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[68] State of Louisiana, Dep't of Natural Res., *Class VI USEPA Primacy Application: Underground Injection Control Program* (May 13, 2021), https://www.dnr.louisiana.gov/assets/OC/im_div/uic_sec/ClassVIPrimacyApplicationstamped.pdf; 88 Fed. Reg. 28,450 (May 4, 2023) (proposed rule to grant Louisiana's primacy application).

[69] *See* Earthjustice, et al., *Comment in opposition to EPA's proposed final rule approving Louisiana's application to implement the UIC program for Class VI injection wells* (July 3, 2023), https://earthjustice.org/wp-content/uploads/2023/07/comments-on-epas-proposed-approval-of-la-class-vi-primacy-application_2023jul03.pdf, included as Exhibit 12.

[70] Int'l Energy Agency, *Global Hydrogen Review 2022*, 71 (Sept. 2022), https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf, included as Exhibit 13.

[71] *Id.*

A. EPA Can Lawfully Require the Use of "Low-GHG" Hydrogen for Purposes of the Hydrogen Co-Firing Compliance Pathway.

To the extent EPA decides to rely on hydrogen co-firing as a component of the BSER for combustion turbines, it has legal authority to require use of low-GHG hydrogen only. As the agency recognizes, different methods of hydrogen production entail vastly different total GHG emissions, 88 Fed. Reg. at 33,315, and any "*best*" system designation for hydrogen must seek to minimize such impacts to the greatest text possible. The agency has therefore proposed to require any power plants that pursue the hydrogen co-firing compliance pathway to utilize only hydrogen that is produced through low GHG-emitting processes. *Id.* As we discuss below, this limitation is within EPA's authority under section 111 of the Clean Air Act.

1. Requirements applicable to fuels are part of a "system of emission reduction."

Section 111 requires EPA to prescribe "standards of performance" for sources. 42 U.S.C. § 7411(b)(1)(B). The statute defines the term "standard of performance" as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." *Id.* § 7411(a)(1). In *West Virginia*, the Supreme Court held that a "best system" designation must be "technology-based." 142 S.Ct. at 2611. However, it clarified that "technologies" in this context "are not limited to literal technology, such as scrubbers," but can also include "changes in the design and operation of the facility, or in the way that employees perform their tasks." *Id.* at 2601 (cleaned up). Indeed, the Court expressly affirmed that cleaner fuels can be—and often have been—eligible for BSER consideration, crediting EPA's prior description of "fuel-switching" as a "more traditional air pollution control measure" of the kind the agency "had always before selected" in BSER determinations." *Id.* at 2611.

In fact, the legislative history of section 111 confirms that Congress intended to grant EPA the authority to require sources to meet emission standards based on the use of cleaner fuels. As enacted in 1970, the definition of "standard of performance" encompassed a broad understanding of the basis for the standards. The Senate's statement on the final version of the bill explained that "[t]he [Conference] agreement authorizes regulations to require new major industry plants . . . [to] achieve a standard of emission performance based on the latest available control technology, processes, operating methods, and other alternatives." 116 Cong. Rec. 42,384 (1970) (Senate Agreement to Conference Report on H.R. 17255).

In 1977, Congress replaced the statutory term "best system of emission reduction" in the context of section 111(b)'s new source standards program with "best *technological* system of *continuous* emission reduction," Clean Air Act Amendments of 1977, Pub. L. No. 95-95, § 109(c)(1)(A), 91 Stat. 685, 699-700 (emphasis added), limiting EPA's ability to effectively require the use of *inherently* lower-emitting fuels. This was part of a protectionist effort by Eastern coal state politicians to deprive Western states, which have lower-sulfur coal than is found in the East, of a competitive advantage.[72]

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[72] Bruce A. Ackerman & William T. Hassler, *Beyond the New Deal: Coal and the Clean Air Act*, 89 YALE L.J. 1466, 1497–1501, 1504–11 (1980).

Even then, however, Congress continued to allow technological or industrial processes to reduce the pollution associated with a fuel inputs as part of EPA's selection of the "best system," providing that "any cleaning of the fuel or reduction in the pollution characteristics of the fuel after extraction and prior to combustion may be credited . . . to a source which burns such fuel." *Id.*

Indeed, in 1979, EPA finalized updated section 111(b) SO_2 standards for coal-fired power plants that included coal-washing in addition to FGD technology as part of the BSER. 44 Fed. Reg. 33,580, 33,611 (June 11, 1979). These coal-washing processes were generally expected to take place upstream of the power plant, and would be reflected in a system of fuel pretreatment credits acquired by plant owners. The D.C. Circuit later upheld this requirement against industry objections as to its technical achievability. *Sierra Club v. Costle*, 657 F.2d 298, 367–74 (D.C. Cir. 1981). In the 1990 Clean Air Act Amendments, Congress reverted to the original "best system of emission reduction" language for section 111(b), Clean Air Act Amendments of 1990, Pub. L. No. 101-549, § 403(a), 104 Stat. 2399, 2631, removing any limitations on EPA's ability to consider the inherent superiority of one kind of fuel over another (e.g., low-sulfur Western coal versus higher-sulfur Eastern coal) for the purposes of new source standards. Of course, under *West Virginia*, EPA's selection of the "best system" must still be "technological" in nature, but it remains the case—and has always been true under section 111—that industrial processes to reduce or mitigate the pollution associated with a fuel meets the applicable definition of "technological."

2. The proposed low-GHG limitation is needed to fulfill EPA's obligations under the Clean Air Act.

EPA's obligation to base standards of performance on the "*best* system of emission reduction" means that EPA must fully consider the overall quantity of pollution reduction the system would achieve. *See Sierra Club v. Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981) (stating that "we can think of no sensible interpretation of the statutory words 'best . . . system' which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling . . . emissions"). The agency's analysis must extend beyond the smokestacks of facilities that are subject to the standard of performance to consider total air emissions. *See id.* at 325–26 (rejecting a petitioner's argument that "EPA may not consider total air emissions in deciding on a proper NSPS" and concluding that "we do not see how we could uphold a [standard of performance] if EPA had not evaluated its effect on air emissions").

Further, section 111 requires that EPA consider these impacts in tandem with the cost of achieving emissions reductions "and any nonair quality health and environmental impact and energy requirements," and EPA's consideration of these other factors is similarly expansive. 42 U.S.C. § 7411(a)(1). As the D.C. Circuit explained in *Costle*, section 111 authorizes EPA "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." 657 F.2d at 330. Indeed, the court in *Costle* rejected a challenge to a standard of performance which EPA selected based in part on its effect on emissions from facilities that were outside the source category. *Id.* at 325 (discussing petitioner's objection "that EPA also took account of the impact of alternative standards on future national levels of sulfur dioxide emissions"). The Supreme Court echoed this broad understanding of EPA's task in *American Electric Power Company v. Connecticut*, explaining that EPA's obligation to consider "energy requirements" refers not just to energy requirements of the specific source or source category, but of the entire nation. 564 U.S. 410, 427 (2011) (characterizing EPA's duty in setting standards of performance: "Along with the environmental benefit potentially achievable, our Nation's energy needs and the possibility of economic disruption must weigh in the balance").

In light of EPA's duty to look comprehensively at the impacts of standards of performance, the Proposed Rule's requirement that power plants complying through hydrogen co-firing only combust hydrogen that is produced through low GHG-emitting processes is well-justified. First, this requirement could dramatically affect the emissions (and emission reductions) resulting from the rule. As EPA notes, "[m]ore than 95 percent of the dedicated hydrogen currently produced in the U.S. originates from natural gas using steam methane reforming," a process that generates carbon dioxide both directly from conversion of methane and indirectly through generation of the thermal energy and steam used in the process. 88 Fed. Reg. at 33,306–07. In contrast, hydrogen produced through the electrolysis of water generates no GHG emissions at the production site and can be powered by low-GHG electricity sources like wind and solar power. *Id.* at 33,307.

Second, the energy requirements associated with low-GHG hydrogen production methods provide significant advantages relative to those for other methods of hydrogen production. Low GHG-emitting electrolyzers can operate flexibly, timing their energy use to take advantage of inherently variable renewable energy resources like wind and solar.[73] Using renewable sources to power electrolysis also promotes energy security by avoiding the unnecessary use of fossil fuel supplies, the extraction and utilization of which are intertwined with geopolitics in complex ways,[74] and avoids the waste of 20 percent of the methane feedstock that typically occurs when using steam methane reforming to produce hydrogen. 88 Fed. Reg. at 33,307 (explaining that the thermal efficiency of steam methane reforming "is generally 80 percent or less"). Further, there is significant potential for energy efficiency advances within electrolytic hydrogen production in the coming years. For example, the recent development of capillary-fed electrolyzers promises potential efficiency levels at or above 95 percent, far exceeding the efficiency performance of steam methane reformers.[75]

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[73] *See* Ando Mehmeti, et al., *Life Cycle Assessment and Water Footprint of Hydrogen Production Methods: From Conventional to Emerging Technologies*, 5 ENVIRONMENTS 24 (2018), https://doi.org/10.3390/environments5020024, included as Exhibit 14 (observing that electrolysis can "avoid the capping/interrupting of generated fluctuating renewable electricity, thus, reducing impacts on power system's reliability, costs and creating a competitive framework for renewable energy sources['] deployment").

[74] For instance, the Russian invasion of Ukraine in early 2022 caused a significant spike in domestic U.S. gas prices for the remainder of that year. EIA, *EIA expects U.S. natural gas prices to remain high through 2022,* https://www.eia.gov/todayinenergy/detail.php?id=52698 (last visited July 30, 2023).

[75] *See* Aaron Hodges, et al., *A high-performance capillary-fed electrolysis cell promises more cost-competitive renewable hydrogen*, 13 NATURE COMMUNICATIONS 1304 (2022), https://doi.org/10.1038/s41467-022-28953-x, attached as Exhibit 15 (demonstrating water electrolysis performance "equating to 98% energy efficiency"); Leigh Collins, *Worlds cheapest green hydrogen*, RECHARGE (Aug. 2, 2022), *at* https://www.rechargenews.com/energy-transition/worlds-cheapest-green-hydrogen-start-up-with-ultra-efficient-electrolyser-to-develop-pilot-factory-after-securing-29m/2-1-1270403 (highlighting one system's capability to achieve 95 percent system efficiency).

In sum, EPA bears an obligation to weigh broader environmental and energy impacts when selecting a standard of performance. The agency must therefore consider all the advantages of hydrogen produced through low GHG-emitting processes, relative to hydrogen produced through higher GHG-emitting approaches. Those considerations show that EPA is lawfully, rationally, and responsibly exercising its discretion in proposing to require power plants to use hydrogen that is produced through low GHG-emitting processes.

B. Any Low-GHG Hydrogen Definition Must Include Proper Carbon Accounting.

EPA proposes to define low-GHG hydrogen as any hydrogen produced through a process that results in a GHG emission rate of less than 0.45 kilograms of CO_2 equivalent per kilogram of hydrogen on a well-to-gate basis, consistent with the system boundary established in IRC section 45V (Credit for Production of Clean Hydrogen) of the Inflation Reduction Act. 88 Fed. Reg. at 33,315. Any definition of low-GHG hydrogen established by EPA in this rule must include reasonable carbon accounting that accurately tracks emissions across the entire lifecycle of the fuel and must exclude credit-swapping schemes that yield emission reductions only on paper. EPA should apply these principles to all hydrogen production pathways. Here, we provide more detail on the appropriate carbon accounting for hydrogen production pathways that power electrolysis with grid electricity and use methane feedstocks.

1. Electrolysis with grid power.

The GHG impacts of producing hydrogen with grid electricity are potentially enormous. DOE has estimated that powering electrolyzers with the grid in the states with the highest fossil fuel penetration would produce hydrogen with a carbon intensity as high as 40 $kgCO_2e/kgH_2$, with the national median at about 20 $kgCO_2e/kgH_2$.[76] Thus, hydrogen produced in this manner is several times more carbon intensive than the "clean hydrogen" Congress has incentivized with production tax credits, which must be less carbon intensive than 4 $kgCO_2e/kgH_2$ to be eligible for the *lowest* tier of subsidy. 26 U.S.C. § 45V(b)(2)(A)(i). Even in a state with a relatively clean grid, like California, hydrogen produced with grid electricity is far more carbon intensive than either fossil methane or hydrogen produced from fossil methane without carbon capture.[77] Properly accounting for the climate impacts of electrolytic hydrogen is essential to ensure federal policies do not inadvertently encourage the use of carbon-intensive hydrogen.

In general, the appropriate way to estimate the climate impact of the electric load a single electrolyzer places on the grid is by calculating the emissions from the marginal EGU on the electrolyzer's

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[76] DOE, *Pathways to Commercial Liftoff: Clean Hydrogen*, 12 (March 2023) https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB.pdf, attached as Exhibit 16.

[77] According to the default values the California Air Resources Board uses in the Low Carbon Fuel Standard Program, compressed fossil gas pipelines in North America has an average carbon intensity of 79.21 gCO_2e/MJ, hydrogen produced from fossil gas through steam methane reformation has a carbon intensity of 117.67 gCO_2e/MJ, and compressed electrolytic hydrogen produced with California grid-average electricity has a carbon intensity of 164.46 gCO_2e/MJ. 17 Cal. Code Regs. § 95488.5(e), Table 7-1.

regional grid in the hours it demands grid energy. This approach reflects the reality that the emissions from running an electrolyzer on grid power are a function of the emissions from the unit that ramps up to meet that additional load. In contrast, using grid-average emissions data to estimate emissions from electrolytic hydrogen production is likely to systemically underestimate emissions. Average emissions data skews the emissions impact of the electrolyzer's additional load by including data for zero-emission resources that would have generated the same amount of electricity regardless of whether the electrolyzer load were on the grid.

In comments on DOE's Clean Hydrogen Production Standard draft guidance, the Institute for Policy Integrity ("IPI") and WattTime showed how using annual average emissions data would significantly underestimate the emissions intensity of electrolytic hydrogen production. For instance, in the Pacific Northwest, hydropower is abundant and lowers the grid's average emissions, but marginal loads are often met with fossil fuels: "[b]ecause there is not enough hydropower to meet the full regional demand for electricity, adding load in the Pacific Northwest from an electrolyzer would require more electricity generation from some other resource to meet total demand, likely a coal or natural gas plant."[78] IPI and WattTime's comments also explain that during one sample period in April 2022, the marginal emissions often oscillated between zero and approximately 800 lb CO_2/MWh in CAISO and between zero and 1,400 lb CO_2/MWh in Southwest Power Pool ("SPP"), demonstrating "how dramatic the misestimation could be if an annual-average approach were used instead of an hourly or sub-hourly marginal emissions approach."[79] To avoid drastically underestimating the hydrogen production emissions that could jeopardize the benefits of the Carbon Pollution Standards, EPA should make marginal grid emissions data the default tool for estimating the impacts of producing hydrogen with grid electricity.

At the same time, it is important to recognize that policies requiring a large additional electric load will incentivize or require the construction of additional and entirely new generation capacity. Indeed, in the coming years, the electric grid will need to expand considerably, with the ongoing shift toward electric vehicles, the replacement of fossil fuel-burning appliances in homes and buildings with electric heat pumps and other alternatives, and—relevant to these comments—the need for electrolyzers to produce low-GHG hydrogen. In this regard, a longer-term view of policies such as the Proposed Rule's s hydrogen component require consideration of what is known as the "long-term marginal emission rate." In contrast to the short-term marginal rate, which "treats the grid assets as fixed," the long-term marginal rate "explicitly takes into account both the underlying evolution of the electric grid, as well as the potential for an incremental change in electrical demand to influence the structural evolution of the grid (i.e., the building and retiring of capital assets, such as generators and transmission lines)."[80] While the short-term marginal rate is superior to the average emission rate for determining whether an affected source is properly sourcing its hydrogen to meet the Proposed Rule's

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[78] IPI & WattTime, *Comments on U.S. DOE's Clean Hydrogen Production Standard Draft Guidance*, 3 (Nov. 4, 2022), https://policyintegrity.org/documents/Institute_for_Policy_Integrity___WattTime_Comments.pdf, included as Exhibit 17.

[79] *Id.*

[80] Pieter Gagnon, NREL, *Long-Run Marginal CO_2e Emission Rates for End-Use Electricity Consumption in the State of Washington*, 4 (June 2021), https://www.nrel.gov/docs/fy21osti/80057.pdf, included as Exhibit 18.

low-GHG requirement for sources combusting hydrogen, EPA must evaluate ways to incorporate long-term marginal emission rates into this calculus.

A carbon accounting framework can reasonably credit an electrolyzer for using zero-carbon electricity when they rely on the electric grid under a narrow set of circumstances. Specifically, EPA's carbon accounting can reasonably characterize a hydrogen producer who uses grid power as using zero-carbon electricity if it can provide verification that they meet each of the following criteria:

1. The hydrogen producer entered an agreement with a newly-constructed ("additional") wind or solar facility to purchase energy bundled with renewable energy credits (RECs) associated with the energy;
2. The hydrogen producer timely retired the RECs and no other entity can claim the emissions benefits of the renewable energy;
3. The electric generator associated with the REC is either connected to the same balancing authority as the hydrogen producer or has an agreement to dynamically transfer electricity to the producer's balancing authority; *and*
4. The hydrogen producer uses the energy in the same hour that the electric generator associated with the REC delivers energy to the grid.

Each of these requirements is essential for the integrity of any claim of using zero-emission electricity.

Research from Princeton University confirms that renewable energy credit swaps are generally ineffective at addressing the carbon impact of grid-powered electrolysis. According to this analysis, electrolysis with grid power can achieve equivalent emissions rates as electrolysis powered by behind-the-meter renewables if the hydrogen producers deploy additional zero-carbon generation resources whose electricity is physically deliverable to the electrolyzers and matches the electrolyzers' demand on an hourly basis.[81] However, to the extent hydrogen co-firing is relied on as a component of the BSER, removing any one of these constraints would lead to spikes in grid emissions.[82] Therefore, EPA's carbon accounting should require hydrogen producers that utilize grid power to meet rigorous standards to demonstrate that they have negated the carbon impacts of their use of the electric grid rather than merely assuming that they have done so.

2. Hydrogen production with methane feedstocks.

It is essential that EPA use appropriate carbon accounting for hydrogen produced from methane feedstocks, which accounts for almost all commercial hydrogen production in the United States

[81] Wilson Ricks, et al., *Minimizing emissions from grid-based hydrogen production in the United States*, 18 ENVTL. RESEARCH LETTERS 11–12 (2023) at 11-12, https://iopscience.iop.org/article/10.1088/1748-9326/acacb5, included as Exhibit 19.
[82] *Id.* at 6-10.

today.[83] This "gray" hydrogen is a more carbon-intensive fuel than fossil gas and, consequently, is not a low-carbon fuel.[84] There is also significant risk that "blue" hydrogen—that is, hydrogen produced from methane feedstocks at facilities with carbon capture equipment—will be an even more carbon-intensive fuel than fossil methane.[85] In general, this risk arises when blue hydrogen producers use fossil gas to power their equipment and the upstream emissions from their induced gas production overwhelm the benefits of capturing on-site emissions.[86] To appropriately account for the lifecycle emissions of producing hydrogen with methane feedstocks, EPA would need to incorporate reliable assumptions for upstream methane leakage and not allow industry to use biomethane to claim emissions offsets.

Accurate information about upstream methane emissions is essential for any analysis of hydrogen produced with methane feedstocks and energy. These emissions account for most of the lifecycle climate pollution of blue hydrogen.[87] However, Argonne National Laboratory's GREET model currently relies on flawed assumptions about fugitive methane emissions. Specifically, GREET assumes that only ~1 percent of methane is lost to fugitive emissions upstream of a hydrogen production facility. This estimate relies on self-reported industry data in EPA's GHG Inventory to estimate fugitive emissions from gas production. The peer-reviewed literature shows that far more than 1 percent of methane from the gas supply chain is lost to leakage. One reputable source for data on the industry's methane leakage is a 2018 study by Alvarez *et al.*, which relies on in-field measurements to estimate that 2.3 percent of gross U.S. gas production is lost to fugitive emissions, and even this figure may be conservative.[88] EPA cannot reasonably rely on the GREET model until it

[83] EIA, *Hydrogen explained: Production of hydrogen*, https://www.eia.gov/energyexplained/hydrogen/production-of-hydrogen.php (last visited Aug. 3, 2023).

[84] Gray hydrogen is inherently more carbon intensive than its methane feedstock because of the energy losses that the production process incurs when it converts the energy from methane into the hydrogen energy carrier.

[85] Robert W. Howarth & Mark Z. Jacobson, *How green is blue hydrogen?*, 9:10 ENERGY SCI. & ENG'G 1676, Tables 2 and 3 (2021) (estimating that hydrogen from a blue hydrogen facility that captures 90 percent of on-site emissions would have lifecycle emissions of 132 gCO_2e/MJ, whereas fossil gas fuel has an estimated lifecycle emissions of 111 gCO_2e/MJ), https://onlinelibrary.wiley.com/doi/epdf/10.1002/ese3.956, included as Exhibit 20.

[86] *Id.* at 1676 (abstract).

[87] *Id.* at Table 1 (in a base case with flue-gas capture, fugitive methane emissions contributed 95.4 gCO_2e/MJ of the total 135 gCO_2e/MJ carbon intensity of blue hydrogen).

[88] Ramón A. Alvarez, et al., *Assessment of methane emissions from the U.S. oil and gas supply chain*, 361:6398 SCIENCE 186 (2018) ("Alvarez 2018"), http://science.sciencemag.org/content/361/6398/186, included as Exhibit 21. GREET relies on this study to estimate emissions from certain stages of the gas supply chain (i.e., gathering, processing, and transmission). Andrew Burnham, Argonne National Laboratory, *Updated Natural Gas Pathways in GREET 2021*, 5, Table 3 (Oct. 2021), https://greet.es.anl.gov/files/update_ng_2021, included as Exhibit 22. However, GREET dramatically underestimates overall leakage because of it relies on unverified data sources for its assumption regarding production-stage emissions, which contribute about 60 of the fugitive emissions from the supply chain upstream of a hydrogen production facility according to Alvarez's measurements. *See id.*; Alvarez 2018 at 187, Table 1.

is updated to incorporate more reliable data on fugitive methane emissions, particularly measurements taken without the cooperation of industry.[89] Instead, any reasonable estimate of upstream methane leakage will very likely exceed 2.3 percent.[90]

To ensure the integrity of its carbon accounting for methane-derived hydrogen, EPA should not provide opportunities for industry to claim that the use of biomethane offsets the emissions from fossil fuels. To start, EPA should not allow hydrogen producers to characterize the methane they use as biomethane through accounting schemes that decouple the purchase of methane gas' energy from its environmental attributes. For instance, in California's Low Carbon Fuel Standard Program, entities that purchase unbundled certificates for the "environmental attributes" of biomethane can claim to use low- or negative-carbon biomethane when they purchase and use fossil gas as a feedstock for hydrogen production. 17 Cal. Code of Regs. § 95488.8(i)(2). Industry has responded to this incentive structure by producing almost all its purportedly "renewable hydrogen" through the steam methane reformation of fossil fuels, without carbon capture.[91] Thus, dubious accounting has allowed hydrogen producers to characterize their product as advancing climate goals without altering their historic practices.

Further, EPA should not allow producers who use a blend of biomethane and fossil methane to claim that "carbon-negative" biomethane offsets the emissions from their fossil fuels. The integrity of the Low Carbon Fuel Standard has suffered because it treats livestock biomethane as a "carbon-negative"

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[89] Alvarez 2018 at 187 (explaining that one potential bias in the EPA inventory data is that "[o]perator cooperation is required to obtain site access for emission measurements. Operators with lower-emitting sites are plausibly more likely to cooperate in such studies, and workers are likely to be more careful to avoid errors or fix problems when measurement teams are on site or about to arrive. The potential bias due to this 'opt-in' study design is very challenging to determine. We therefore rely primarily on site-level, downwind measurement methods with limited or no operator forewarning to construct our [bottom-up] estimate.") (footnote omitted).

[90] *See, e.g.*, Genevieve Plant et al., *Inefficient and unlit natural gas flares both emit large quantities of methane*, Table 1, 377:6614 SCIENCE 1566–1571 (2022) (finding that flares only destroy 91.1 percent of methane, which is significantly less than the 98 percent efficiency assumed in previous estimates), https://www.science.org/doi/10.1126/science.abq0385; Robertson, et al., *New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates*, 54 ENVTL.. SCI. TECH. 13,926–34 (2020), https://pubs.acs.org/doi/abs/10.1021/acs.est.0c02927; Jeff Peischl et al., *Quantifying Methane and Ethane Emissions to the Atmosphere From Central and Western U.S. Oil and Natural Gas Production Regions*, 123:14 J. OF GEOPHYSICAL RESEARCH: ATMOSPHERES 7725, 7731, Table 1 (2018) (relying on measurements from aircraft to estimate leakage rates in several shale basins: 5.4 percent in the Bakken, 3.2 percent in Eagle Ford East, 2.1 percent in the Denver Basin, 2.0 percent in Eagle Ford West, 1.5 percent in the Barnett, and 1.0 percent in the Haynesville shale region), https://agupubs.onlinelibrary.wiley.com/doi/epdf/10.1029/2018JD028622, included as Exhibit 23.

[91] *See* John Eichman & Francisco Flores-Espino, NREL, *California Power-to-Gas and Power-to-Hydrogen Near-Term Business Case Evaluation*, 59 (Dec. 2016), https://www.nrel.gov/docs/fy17osti/67384.pdf, included as Exhibit 24 (most of the "renewable" hydrogen dispensed in California is "produced from SMR and coupled with the purchase of biogas credits").

resource. This practice has created a windfall for factory farms that began capturing biogas a decade ago to generate electricity and maximize revenue by diverting their biomethane to generate Low Carbon Fuel Standard credits. For instance, a hydrogen producer recently received permission to claim that hydrogen produced with pipeline gas in California has a carbon intensity of -282.30 gCO_2e/MJ because the producer purchased environmental attributes from a dairy in New York,[92] suggesting that the biomethane would have vented into the atmosphere but for the Low Carbon Fuel Standard. However, the dairy in question has, in fact, captured its biomethane for over a decade to generate electricity.[93] Treating biomethane as carbon negative invites gaming: hydrogen producers who blend two kilograms of hydrogen produced from fossil gas (which has a carbon intensity of about 118 gCO_2e/MJ) with one kilogram of hydrogen produced from biomethane (with a purported carbon intensity of about 282 gCO_2e/MJ) might claim that their gray hydrogen is better than "net zero." 17 Cal. Code Regs. § 95488.5(e), Table 7-1. This type of offsetting scheme both leads to inaccurate carbon accounting and undermines the market for truly low-carbon hydrogen by improperly allowing hydrogen producers to characterize gray hydrogen as low-carbon.

C. EPA Should Ensure that the Low-GHG Hydrogen Requirement Is Severable from the Remainder of the Standard.

EPA has solicited comments on "whether the low-GHG hydrogen requirement could be treated as severable from the remainder of the standard such that the standard could function without this requirement." 88 Fed. Reg. at 33,316. Although the low-GHG requirement for hydrogen is important to achieving net GHG emission reductions from the use of hydrogen to control combustion turbine stack emissions, the proposed rule would still prescribe a coherent—if incomplete—regulatory program in the absence of the low-GHG hydrogen requirement. Sources subject to the proposed stack emission limits would achieve those limits even if they combust hydrogen that is generated through high-GHG emitting processes. Compliance with the proposed standards could therefore proceed in the absence of the low-GHG hydrogen requirement.

To the extent EPA agrees that the low-GHG hydrogen requirement should be severable, achieving that outcome is a matter within EPA's control. The D.C. Circuit has explained that "[s]uccessful challenges to one aspect of a rule yield partial vacatur unless there is 'substantial doubt' that the agency would have left the balance of the rule intact." *Finnbin, LLC v. Consumer Prod. Safety Comm'n*, 45 F.4th 127, 136 (D.C. Cir. 2022) (quoting *North Carolina v. FERC*, 730 F.2d 790, 796 (D.C. Cir. 1984)). Thus, the severability of a portion of a final rule "turns on agency intent." *NASDAQ Stock Market v. SEC*, 38 F.4th 1126, 1144-45 (D.C. Cir. 2022). That is particularly true where, as here, the remaining requirements of the rule can function absent the severed portions. *See id.* at 1145 (explaining that the court looks to "whether the valid portions can function absent the

[92] California Air Resources Board, *Staff Summary of Application No. B0430*, 4 (June 25, 2023), at p. 4, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0430_summary.pdf, included as Exhibit 25.

[93] Int'l Council on Clean Transp., *Comments on LCFS Application No. B0430*, 2 (June 2, 2023), https://www.arb.ca.gov/lists/com-attach/980-tier2lcfspathways-ws-Vj8GY1c1ACcLUlc0.pdf?_ga=2.178929124.1773549129.1689005792-466423198.1662166685, included as Exhibit 26.

invalid portions”). To ensure the severability of the low-GHG hydrogen requirement, EPA needs to clearly explain its position on this issue in the final rule.

Regardless of whether the low-GHG hydrogen component of the Carbon Pollution Standards are ultimately included in the final rule, EPA must undertake a process of comprehensively regulating hydrogen production facilities under the Clean Air Act and any other appropriate legal authority, which will require one or more additional rulemakings. As discussed above, these facilities can emit substantial quantities of GHGs and other pollutants (including air toxins from certain modes of production), yet are not currently subject to Clean Air Act standards. Especially in light of the hydrogen production industry’s potential growth in the coming years, EPA must ensure that these facilities are controlled to the greatest extent possible. Additionally, PHMSA must work to issue robust safety standards for the pipeline infrastructure that will transport these fuels.

VIII. MONITORING, REPORTING, AND COMPLIANCE CONSIDERATIONS.

The Proposed Rule requires units to follow the standard EPA monitoring and reporting requirements provided at 40 C.F.R. part 75. 88 Fed. Reg. at 33,390. These monitoring protocols generally involve measuring both the rate of flow of the gas exiting the unit’s stack and the concentration of CO_2 in that stack gas. However, measuring flow is difficult, especially where the measuring point is located near sources of disturbance, such as bends in piping. EPA’s methods have thus been shown to permit large errors in flow estimates. Ironically, even while EPA asserts in the rule preamble that Part 75’s CO_2 concentration protocols are “verified based on [National Institute of Standards and Technology, or NIST] traceable standards,” *id.* at 33,391, NIST’s own scientists have sharply criticized EPA’s methodology for stack flow measurement, observing that

> [p]resently used methods to measure CO_2 and other emissions from smoke stacks have errors of 20% or more depending on the level of swirl in the flow.[94]

A 20 percent error in a program dealing with several million tons of CO_2 per year is no small thing and should not be tolerated where better and cheaper alternatives exist. In this section, we discuss the problems inherent in Part 75’s methodology and offer alternatives that would substantially improve

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[94] NIST, *Smoke Stack Flow Measurement*, https://www.nist.gov/programs-projects/smoke-stack-flow-measurement (last visited Aug. 3, 2023); *see also* Aaron Johnson, et al., *Progress Towards Accurate Monitoring of Flue Gas Emissions* (paper delivered to the 10th International Symposium on Fluid Flow Measurement in Querétaro, Mexico, March 21–23, 2018), http://www.measurementlibrary.com/docs_library/events/isffm2018/Docs/Johnson.pdf, included as Exhibit 27; John Wright and James R. Whetstone, *Overview of Fluid Metrology and Greenhouse Gas Measurements Programs* (paper delivered to the NIST Smokestack Emission Conference, June 2017); Leslie L. Sloss, *Efficiency and Emissions Monitoring and Reporting* (Sept. 2011), https://www.researchgate.net/profile/Lesley-Sloss/publication/337487261_Efficiency_and_emissions_monitoring_and_reporting/links/5ddbb59ea6fdccdb44632548/Efficiency-and-emissions-monitoring-and-reporting.pdf, included as Exhibit 28.

EPA's monitoring and reporting requirements. We also discuss other changes EPA should make it its monitoring, reporting, and compliance requirements.

A. EPA's Part 75 Emissions Measurement Protocols Are Not Sufficiently Accurate.

In Section IV, we discussed Sierra Club's 105-Unit Study, which provides a comprehensive look at power plant efficiency over time. In addition to its data on power plant heat rate trends, the study also provides insight into EPA's monitoring regime: its results strongly suggest that operators are not complying with the 40 C.F.R. Part 75 requirement that sources *"accurately* report their CO_2 concentration and stack flow rate data. 40 C.F.R. § 75.10(f) (emphasis added).[95] More to the point, the results indicate that EPA's currently approved emissions measurement techniques are insufficient and must be replaced with a far more rigorous protocol.

Part 75 provides an option for sources to estimate their CO_2 emissions based on weekly coal carbon content sampling and ongoing estimates of coal consumption.[96] This technique is notoriously unreliable, with some sources using photographs of the size of their coal piles to estimate coal consumption.[97] This in itself is a major problem, as it allows for glaring measurement inaccuracies and allows sources to "estimate" their way into easier compliance scenarios

Use of Part 75's continuous emission monitoring ("CEM") protocols does not resolve these problems. This method includes two basic components for measuring sources' emissions. First, the operator must measure the rate of flow of the flue gas exiting the stack (i.e., the "stack flow") over a given time interval. Second, the operator must measure the concentration of CO_2 that exists in the flue gas (adjusted for moisture). By combining these two measurements, the operator can determine (and report) the amount of CO_2 that the source is emitting over the time interval. To report the source's output-based emission rate, the operator divides that quantity of measured CO_2 by the amount of electricity generated over the same time period (a gross-output measurement uses the quantity of electricity produced by the unit's generator, and a net-output measurement uses the quantity of generated electricity that is supplied to the grid).

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[95] EPA generally permits states to include the Part 75 requirements in their plans in order to satisfy section 111(d)'s monitoring, recordkeeping, and reporting requirements. *See, e.g.*, proposed 40 C.F.R. § 60.5785a(a)(1).

[96] 40 C.F.R. Part 75, Appendix G, Section 2.11.

[97] *See* Gurney, et al., *Bias present in US federal agency power plant CO_2 emissions data and implications for the US clean power plan*, 11 ENVTL. RESEARCH LETTERS 064005 (2016), http://iopscience.iop.org/article/10.1088/1748-9326/11/6/064005/pdf; included as Exhibit 29; Katharine V. Ackerman and Eric T. Sundquist, U.S. Geological Survey, *Comparison of Two U.S. Power-Plant Carbon Dioxide Emissions Data Sets*, 42 ENVTL. SCI. TECH., 5688–93 (2008), https://darchive.mblwhoilibrary.org/server/api/core/bitstreams/0ee1b852-9458-500a-b7e9-3ec1351a1bc7/content, included as Exhibit 30; Jeffrey C. Quick, *Carbon dioxide emission tallies for 210 U.S. coal-fired power plants: A comparison of two accounting methods*, 64 J. OF THE AIR & WASTE MGMT. ASSOC., 73–79 64 (2014), https://www.tandfonline.com/doi/pdf/10.1080/10962247.2013.833146, included as Exhibit 31.

The problem with this approach is that it allows a significant margin error at both the stack flow and CO_2 concentration components of the measurement process. In fact, the level of error is sufficiently high such that sources may either fail to detect any emission reductions achieved through HRI or report an emissions improvement where none has actually occurred. Part 75 requires that each of the two measurement parameters (CO_2 concentration and stock flow rate) be accurate to within +/ 10 percent of the "reference" method determination. Thus, the combined relative accuracy requirement of this two-step measurement process is +/- 21%.[98] This potential level of error threatens to badly erode the emission reductions expected under the rule, and would allow units that, under the rule, must merely maintain their current emission rate to in fact undergo substantial and undetected backsliding. In addition, as a result of Part 75's large allowance for error, some operators may mistakenly believe that they are authorized to report information that they know is inaccurate if it meets relative accuracy ("RATA") requirements.[99] For instance, an operator might simply recalibrate its measurement equipment in a manner that shows an emissions improvement when the operator has done nothing that actual improve the source's efficiency.

Moreover, unlike CO_2 concentrations (which have a NIST-traceable standard), there has historically been no primary reference for stack flow.[100] Rather, the EPA relative accuracy requirement compares the CEM data to stack flow data conducted according to EPA Method 1 or 2. EPA acknowledges that these methods are subject to errors induced by non-linear flow in the stack and provides a methodology for determining whether this error is "acceptable," but does not identify the overall error that should be assumed. There have been numerous studies citing the difficulties and uncertainties associated with Method 1 and 2 stack flow measurement.[101] For these reasons, the misreported CO_2 emission rates described in more detail in the following subsection are most likely the result of inaccurately measured flow rates.

Furthermore, while Part 75's +/- 10 percent degree of uncertainty is facially neutral in that the error could point in either direction, the operator is free to recalibrate the continuous flow monitor where the prior calibration would result in an *overprediction* of emissions. However, the operator is not

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[98] Compare a concentration of 0.10 and a flow of 1,000,000 = mass of 100,000 with a concentration of 0.11 and a flow of 1,100,000 = mass of 121,000. Note also that EPA allows sources to use "nominal" moisture factors in lieu of actual measurements.

[99] Where EPA's Office of Air Quality, Planning, and Standards determines that a source is underreporting emissions data submitted under Part 75 that EPA has reason to believe is inaccurate, EPA must require immediate correction; if the source fails to do so, the agency must promptly refer the matter to the Office of Enforcement and Compliance Assurance and the Department of Justice for prosecution.

[100] NIST now offers calibration services for pitot tubes.

[101] *See, e.g.,* Scott Swiggard, NIST, *Volumetric Flow Measurements of Stationary Sources: Common Mistakes, Corrective Measures* (Apr. 2015), https://www.nist.gov/system/files/documents/2017/10/31/volumetric-flow-measurements-stationary-sources.pdf, included as Exhibit 32; R.A. Robinson, et al., UK Nat'l Physical Lab., *Problems with Pitots. Issues with flow measurement in stacks*. (2014), https://www.envirotech-online.com/white-paper/air-monitoring/6/cem/problems-with-pitots-issues-with-flow-measurement-in-stacks/107, included as Exhibit 33.

required to correct the continuous monitoring data in all instances where the calibration *underreports* emissions compared to the reference method results. Indeed, the agency's bias testing procedures do not require an adjustment to an underreporting error documented in the RATA testing unless that bias is so large that it fails an assigned statistical test that EPA concedes is "very forgiving."[102] Rather than correcting for this deficiency, the proposed rule would exacerbate the problem by expressly forbidding the operator from correcting the CEM data for underreporting bias.

B. Sierra Club's 105-Unit Study Reveals Significant Underreporting of Coal Plant CO_2 Emissions, Which Affirms the Flaws in EPA's Monitoring Protocols.

The shortcomings with Part 75 are not mere theoretical concerns, but are strikingly apparent in the data itself. As discussed in Section IV, Sierra Club's 105-Unit Study involved a review of daily emission and generation data from 2001 to 2017 of 105 coal- and gas-fired units—over 14 million daily operation records. The purpose of the study was to help determine the extent to which existing power plants could improve their efficiency on an ongoing basis. As described above, the study showed that the majority of units exhibit a substantial variation in their efficiency that can only be explained by suboptimal operation and maintenance practices. However, the study also found widespread underreporting of CO_2 emissions from coal-fired EGUs. For example, some units reported emission rates for several years that would literally be impossible given the design of those facilities. By way of example, Table 7 below sets out the 12-month average in 2017 for Kentucky's Mill Creek plant—comprised of several aging subcritical coal-fired units—compared with the ultra-supercritical JW Turk plant and the supercritical IGCC Edwardsport plant. It also provides data for two subcritical units at the (now-decommissioned) San Juan Generating Station, which, prior to their retirement, were comparable in age and technology to Mill Creek.

Table 7. Reported Emission Rates (Average of 2017 Monthly Averages)

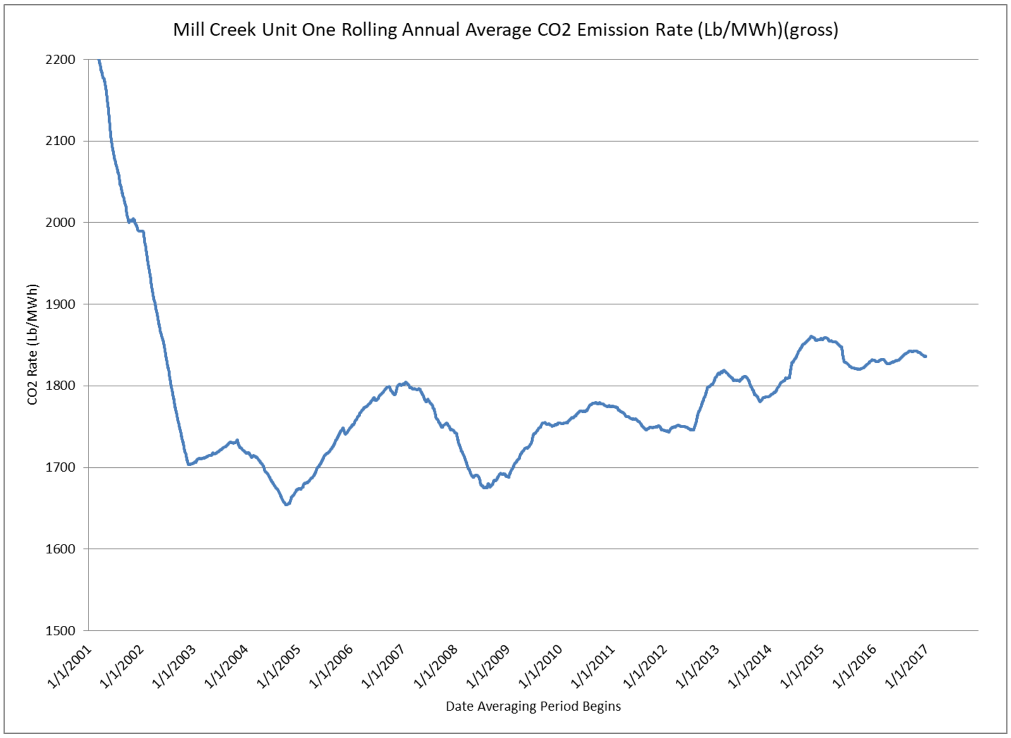
Plant (technology)	CO_2 Emission Rate (lb/MWh–g) Reported to EPA
Mill Creek Unit One (subcritical)	1,826
JW Turk (ultra-supercritical)	1,874
Edwardsport 1 (supercritical IGCC)	2,065
Edwardsport 2 (supercritical IGCC)	2,157
San Juan 1 (subcritical)	2,170
San Juan 2 (subcritical)	2,299

It is simply not technologically possible for a subcritical coal steam unit like Mill Creek Unit 1—which was 45 years old by 2017—to operate at emission rates 2.5 percent lower than a 5-year-old ultra-supercritical unit (Turk) and at rates 11–15 percent lower than 5-year-old supercritical IGCC facility. Furthermore, 2017 was not an anomalous year for Mill Creek; in fact, it was one of the periods between approximately 2003 and 2017 with the *highest* reported emission rates. Nor is there

[102] *See* EPA, *An Operator's Guide To Eliminating Bias In CEM Systems, Chapter 1—Overview: Accuracy, Precision, and Bias in Continuous Emission Monitoring Systems*, 1-8 (Nov. 1994), https://www.epa.gov/sites/default/files/2015-05/documents/chapter_1_overview_accuracy_precision_and_bias_in_continuous_emission_monitoring_systems.pdf.

any technology apart from CCS or very large amounts of gas co-firing capable of reducing CO_2 emission rates from an operating coal plant by 500 lb/MWh, as Mill Creek reported between 2001 and 2003.

Fig. 24: Mill Creek Unit One Rolling Annual Average CO_2 Emission Rate (lb/MWh-g)



All told, 43 of the 51 coal-fired units in the study reported at least one year of operation at rates that are not credible for subcritical units of their age. Half of these units (25/51) did so in 2017, even though 40 C.F.R. Part 75 requires operators to "*accurately*" report the CO_2 concentration and stack flow rates. As noted above, EPA's 40 CFR Part 75 sets out the continuous monitors for flow must be accurate to within +/ 10 percent of the "reference" method determination and provides similar tolerances for concentration and moisture. Since the mass of CO_2 emissions is the product of the measured flow and CO_2 concentration adjusted for moisture, the combined relative accuracy requirement is less than that for any one factor. However, EPA's regulation makes it clear that the results are "valid," and that operators are authorized to report information even if they know it is inaccurate, if it meets RATA requirements.[103] Figures 25 and 26 below reflect just how widespread the problem of underreporting is.

[103] Note that "relative accuracy" methods compare test results using different methods, and do not determine the absolute accuracy of the result. EPA's rules provide that the RATA conditions override the common meaning of the requirement to "accurately" report emission data.

Fig. 25: 2001–2107 Low Rolling Annual Average CO_2 Emission Rate (lb/MWh-g) of Coal Units in the 105-Unit Study

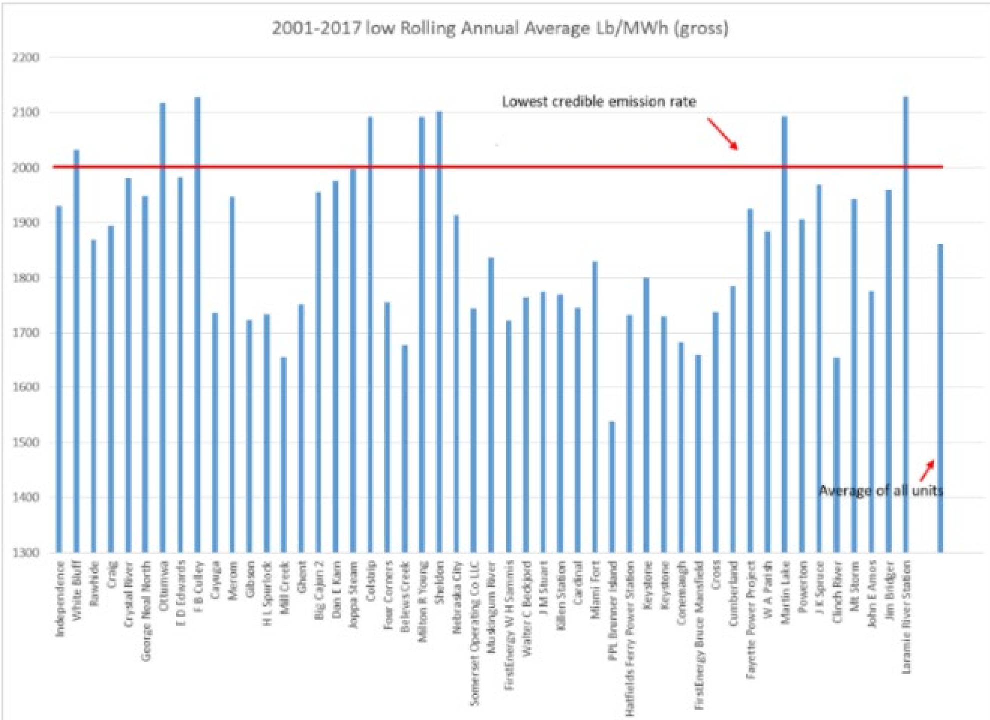
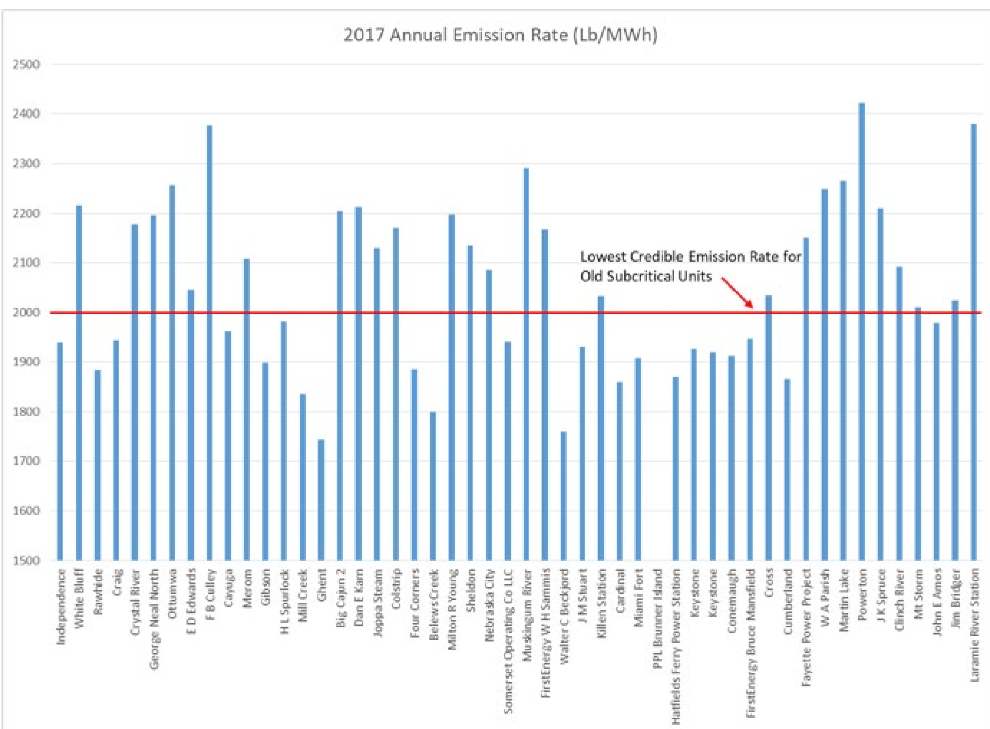


Fig. 26: 2017 Annual Emission CO_2 Emission Rate (lb/MWh-G) of Coal Units in the 105-Unit Study



C. EPA's Final Carbon Pollution Standards Must Include the Enforcement and Monitoring Protocol Discussed Below or One That Is at Least as Accurate.

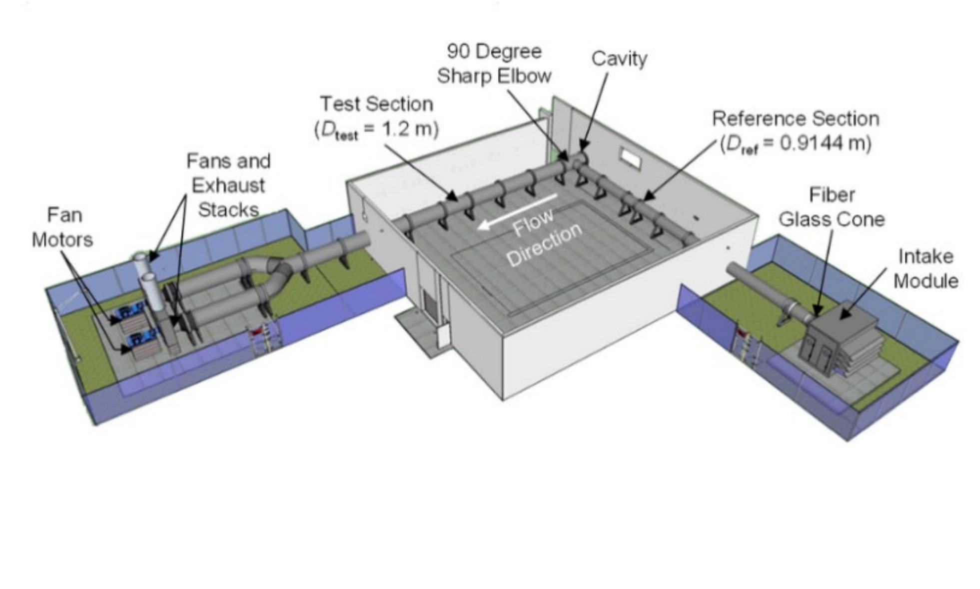
Section 111 requires EPA to select the BSER for regulated source categories, which establishes the degree of emission limitation that performance standards must achieve. 42 U.S.C. § 7411(a)(1), (b)(a)(B), (d). Historically, EPA's BSER designation has included only the technology itself to reduce emissions, while requirements regarding monitoring, recordkeeping, and reporting protocols have been included separately. As explained above, however, under the Part 75 emissions monitoring and reporting protocols, there is no guarantee that these performance standards actually *will* result in the quantity of emission reductions achievable through the BSER; on the contrary, the 105-Unit Study reveals that sources can and often do report emission rates that suggest illusory performance improvements. In other words, the BSER will be ineffective unless it encompasses specific emissions measurement techniques that will guarantee a far greater degree of accuracy than the current Part 75 provides. To properly reflect the emission reductions achievable through the BSER, state plans must require sources to adhere to the techniques discussed below or another equally accurate protocol.

Given the inherent difficulty in measuring stack flow, CEM-based information must be correlated with long-term fuel sampling and consumption data. In order to determine the effect of any modification on efficiency, before-and-after reference method testing should be mandated. These requirements would both determine whether the source had satisfied the mandatory emission rate described in its applicable standard of performance. The effect of any change in calibration must be accounted for in the compliance determination. In addition, sources must conduct pre- and post-upgrade ASTM heat balancing testing to reduce any errors in stack flow measurements resulting from non-linear flow. These suggested requirements are intended to ensure that sources do not achieve "false compliance" with their mandatory emission rates by merely recalibrating their flow or CO_2 monitors or installing, but failing to maintain, new technology.

NIST has also developed an approach that improves the accuracy of the reference method against which continuous monitors are calibrated. Flow meters are commonly based on pitot tubes, which are measuring devices that have been used for centuries to gauge the pressure drop of the flue gas as it enters a hole in a tube of established size and volume. The pressure drop between a tube facing the flow and a tube facing away from the flow is a function of the flow velocity and the density of the fluid being measured. However, pitot tubes must be calibrated against the actual flow to establish the mathematical relationship between the pressure drop and the flow rate. Since calibration in a real stack is problematic, pitot tubes are typically calibrated in standardized conditions using smooth flowing fluids. Actual flows may deviate appreciably from the calibration conditions, especially if the flow is swirling in a cyclonic fashion as it moves up the stack. In these conditions, it is difficult to arrange standard design pitot tubes so they are properly positioned with respect to flow.

To address this problem, NIST constructed a large-scale smoke stack simulator (depicted in Figure 27 below) that accurately mimics the conditions in power plant stacks that can lead to cyclonic flow and conducted several years of research in collaboration with the Electric Power Research Institute and industry partners to develop better designs of pitot tubes and calibration procedures.

Fig. 27. NIST Smoke Stack Simulator[104]



According to NIST, its "field tests at power plant stacks show that NIST designed sensors and methods reliably attain 2% uncertainty regardless of the swirl level in the flow. NIST smoke stack profiling methods and sensors are resistant to plugging by solids and water in smoke stacks, are 4x faster, and are 10x more accurate than presently used methods." [105] In fact, NIST reports that its techniques and probes provide nearly 1 percent accuracy at a 95 percent confidence level.[106] EPA should adopt NIST's flow measurement techniques in the final Carbon Pollution Standards, or otherwise allow sources to use another approach that has been NIST-certified and that achieves flow measurement accuracy with no more than 2 percent uncertainty.

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[104] John Wright & James R. Whetstone, *Improving Measurement for Smokestack Emissions*, 8 (June 2022), https://www.nist.gov/system/files/documents/2017/11/21/ppt_wright_whetstone_ghg_science_measurements_program.pdf, included as Exhibit 34.

[105] NIST, *supra* n. 94; *see also* NIST, *Air Speed Metrology*, https://www.nist.gov/programs-projects/air-speed-metrology (last visited Aug. 3, 2023); Iosif I. Shinder, et al., NIST, *NIST's New 3D Airspeed Calibration Rig, Addresses Turbulent Flow Measurement Challenges* (paper delivered to the 9th International Symposium on Fluid Flow Measurement in Arlington, Virginia, April, 14–17, 2015), https://view.ckcest.cn/AllFiles/ZKBG/Pages/680/918356.pdf, included as Exhibit 35.
Aaron Johnson, et al., NIST, *Progress Towards Accurate Monitoring of Flue Gas Emissions* (paper delivered to the 10th International Symposium on Fluid Flow Measurement in Querétaro, Mexico, March 21–23, 2018), https://tsapps.nist.gov/publication/get_pdf.cfm?pub_id=925357, included as Exhibit 36.

[106] Iosif Shinder, et al., NIST, *Characterization of Five-Hole Probes used for Flow Measurement in Stack Emission Testing* (May 16, 2018), https://tsapps.nist.gov/publication/get_pdf.cfm?pub_id=925551, included as Exhibit 37.

The remaining step is fairly simple. Part 75 already requires that operators certify that their reported data are "accurate." Currently required relative accuracy testing permits a correlation between the NIST improved reference method testing and the data generated by the continuous monitoring systems. But EPA's "relative accuracy testing is "pass/fail," and the measured difference between the reference method testing and the continuous monitoring is ignored as long as it is below a certain level. All that is required is that the permitting authority specifically require that such a correlation be calculated and employed to adjust the CEM data (upward or downward as appropriate, but without EPA's confidence interval added in favor of the operator). EPA's regulations should then specify that compliance is to be based on such adjusted data. This outcome adds no cost to the program and is fair to the operators, but eliminates the potential for source operators to cherry pick calibration outcomes as a means of complying with the standard.

D. EPA Must Revise its Proposed Rounding Provisions.

Suppose that a new intermediate-load combustion turbine subject to the Phase 2 standard of 1,000 lb/MWh emits 1,042.525 lb/MWh over a given compliance period. (As discussed in Section III, our recommendation of NGCC technology as the "best system" for intermediate-load turbines would entail a Phase 2 standard far more stringent than 1,000 lb/MWh, but we select this figure here because it provides a good illustrative case.) One would naturally conclude that the unit has exceeded its emission limit and is in violation of the standard. However, under the Proposed Rule's regulatory text, an emission rate of up to 1,049.9 lb/MWh would be rounded down to 1,000 lb/MWh and deemed compliant with the standard. This interpretation reflects an agency policy dating back to 1990 that directs EPA to use at least two, but not more than three, significant figures[107] for all emission standards.[108] This permits sources with nontrivial overages to remain in compliance with the standard in many cases, in contrast to the previous EPA policy in which *any* amount over the expressed limit constituted an exceedance. Suffice it to say that Congress likely did not intend for sources such as the aforementioned unit to emit nearly 23,000 tons of CO_2 per year[109] above EPA's nominal limit simply because the agency did not include a period immediately after the number (i.e. 1,100. compared to 1,100).

We strongly urge EPA to withdraw the 1990 policy specifying either two or three significant digits for determining compliance and to abandon the proposal's regulatory text codifying this policy. Instead, the agency must coordinate all significant digit protocols with its guidelines on the intermediate calculations that operators must perform to determine their reporting values. The 1990 document directs that these calculations, must be carried out to no fewer five significant figures.[110] There is no

[107] "The number of significant figures in a result is simply the number of figures that are known with some degree of reliability. The number 13.2 is said to have 3 significant figures. The number 13.20 is said to have 4 significant figures." Yale University Dep't of Astronomy, *A Short Guide to Significant Figures*, 1, http://www.astro.yale.edu/astro120/SigFig.pdf.
[108] EPA, *Technical Information Document 024 - Memo on Rounding and Significant Figures*, 2–3 (1990), https://www.epa.gov/emc/technical-information-document-024-memo-rounding-and-significant-figures.
[109] This figure assumes that the unit is a 300 MW simple cycle combustion turbine operating at a 35 percent annual capacity factor, a representative figure for intermediate-load operations.
[110] EPA, *supra* n. 108, at 5.

reason to report the final result in fewer significant figures than are used in the intermediate calculations, particularly since the agency's current policy allows sources additional "free" tons of pollution without any policy justification. Thus, the final Carbon Pollution Standards should require the use of five significant figures in calculating the final result as well. Under this policy, an emission rate of 1,042.525 lb/MWh would, for compliance purposes, calculate as 1,042.5 lb/MWh rather than 1,000 lb/MWh.

Most fundamentally, there is no particular reason why an emission rate should be "rounded up" at all. EPA must always have a valid technical basis for setting a standard in the first place, and if the result of that technical analysis calls for a standard of 973 lb/MWh, that standard should be set at 973, or perhaps 975, but not 980 or 1,000.

E. EPA Must Adopt Stringent Requirements for Missing Data.

The Proposed Rule's regulatory text pertaining to "valid" data is as follows:

> (1) Each compliance period shall include only "valid operating hours" in the compliance period, *i.e.,* operating hours for which:
> (i) "Valid data" (as defined in §60.5580a) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and
> (ii) The corresponding hourly gross or net energy output value is also valid data (*Note:* For hours with no useful output, zero is considered to be a valid value).
> (2) You must exclude operating hours in which:
> (i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;
> (ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO2 mass emissions or, if applicable, to determine the hourly heat input;

Proposed 40 C.F.R. § 60.5540(a)(1). EPA should ensure that for *every* hour in which an EGU operates, its generation during for that hour counts towards a determination of the unit's capacity factor and thus its applicable emission rate, including hours where generation data are available but emissions data are not. Where data is missing due to a CEM malfunction, EPA should require the use of Part 75 substitute data; one option would be to use of the highest hourly rate in the prior 30 operating days. As for scenarios in which the CEM reports emissions that exceed the upper limit of the monitor's full-scale range rather than effectively rewarding operators for such periods of operation by effectively rejecting the data, EPA should penalize them by requiring a multiplier. For example, the regulation could provide that where the CEM shows an exceedance of the full-scale range, the source should report some figure such as 150th percent of the highest value of the upper limit of that full-scale range.

IX. EPA MUST CONSISTENTLY UPHOLD TECHNOLOGY-FORCING ASPECTS OF SECTION 111 AND AVOID CATERING TO THE LOWEST-COMMON DENOMINATOR.

Repeatedly throughout these comments, we have emphasized the fact that Congress designed section 111 as a technology-forcing provision, not a technology-following one. *Sierra Club v. Costle*, 657 F.2d 298, 364 (D.C. Cir. 1981) ("EPA does have authority to hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard."); *Nat'l Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 785 (D.C. Cir. 1976) (cleaned up) ("[S]ection 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present."); *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433–34 (D.C. Cir. 1973) ("An achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption."). Certainly, in several aspects of this rule—such as the requirements for long-term coal units and for new baseload combustion turbines—EPA has designed the standard with an eye toward the technological future, rather than the technological past.

Yet in various other regards, EPA's proposal (particularly but not only for new sources) caters unnecessarily to industry's *status quo* preferences, accommodating environmentally inferior practices merely because power plant owners may want to continue them on into the future. This is particularly apparent in the exceedingly broad leeway that the current proposal would give operators in running simple cycle gas turbines at capacity factors far higher than their engineering specifications would typically call for. Despite the fact that combined cycle units are far more efficient than simple cycle turbines, have lower operational costs and comparable (and often cases lower) per-kilowatt capital costs, and already serve the vast majority of non-peaking generation needs among the universe of gas-fired EGUs, the agency nonetheless takes pains to ensure that *new* simple cycle units will be permitted to run at annual capacity factors of up to 40 percent. Section III of these comments provides a detailed discussion of why EPA should substantially revise this aspect of the rule.

We see this same logic in various other aspects of the rulemaking. For example, the agency proposes two input-based standards for new low-load combustion turbines: one of 120 lb CO_2/MMbtu for units firing gas and one of 160 lb CO_2/MMBtu for units firing petroleum-based fuels. Proposed 40 C.F.R. §60.5525a(a)(2). As discussed in Section III, neither standard would achieve any emission reductions in practice from new units, and we have instead proposed output-based standards for the low-load subcategory that would require use of the best or near-best CT technology. Yet even considering just the input-based standard, EPA does not explain why it is allowing the unfettered operation of new oil-fired turbines in the first place, given that the fuel itself has one-third more CO_2 content than gas, or why it has at least not distinguished between continental and non-continental oil-fired units, just as it has done for existing oil- and gas-fired steam EGUs. Relatedly, in its emission guidelines for existing steam EGUs, the agency has defined "[c]oal-fired steam generating unit" in a way that would allow existing coal plants to effectively avoid anything other than BAU regulatory requirements by fully converting to gas *or* oil by December 31, 2029. Proposed 40 C.F.R. § 60.5880b. Although few (if any) such units may wish to convert to oil, there is no reason for EPA to allow this this possibility on a forward-looking basis—even in theory—when lower-emitting options are available.

As another example, EPA rejects the idea that "efficient design and operation qualify as the BSER for the low-load subcategory," since highly-efficient units are marginally higher in capital costs (5 percent) compared to lower efficiency units. 88 Fed. Reg. at 33,285.[111] Again, EPA caters to the lowest common denominator rather than force the state of the technology forward. Even while the agency acknowledges that high-efficiency CTs use approximately 6 percent less fuel than lower-tier units, it suggests that "it would not necessarily be cost reasonable to use a high-efficiency simple cycle turbine until the combustion turbine is operated at a 12-operating-month capacity factor of approximately 20 percent." *Id.* EPA provides no data to support this assertion, and appears to assume that because some unspecified number of units *might* find it economically suboptimal to install highly efficient CT technology, the agency *must* select a more accommodating "best system" measure.

Here, again, the agency deems it necessary not just to help perpetuate the industry's current references at the expense of technological advancement, but to actually ensure that operators pay no additional net costs in reducing their emissions. This both conflicts with Congress's legal directive in designing section 111 and with the entire purpose of an environmental regulator. Of course, EPA may not issue section 111 regulations that would be economically ruinous, but it is no more appropriate to reject an environmentally superior technology merely because an operators' net costs will be greater than zero. These are just a few examples of the accommodationist approach that appears in multiple places throughout the proposal. As it develops the final Carbon Pollution Standards, EPA must ensure that each and every regulatory choice reflects section 111's technology-forcing mandate, and remember that its job is not to cater to minimize the burden on industry, but to provide the greatest environmental protection possible while still addressing section 111's other statutory factors.

X. CONSIDERATIONS REGARDING VARIANCES BASED ON REMAINING USEFUL LIFE AND OTHER FACTORS (RULOF).

In its proposed emission guidelines, EPA has established what Joint Environmental Commenters believe is, by and large, a reasonable, well-balanced approach to the availability of source-specific variances in state plans that reflect remaining useful life and other factors (RULOF). This approach is consistent with the amendments to EPA's section 111(d) implementing regulations that the agency proposed in December 2022. 87 Fed. Reg. 79,176, 79,196–79,206 (Dec. 23, 2022). In comments responding to that proposal, a number of environmental and public health organizations (including Sierra Club and Earthjustice) observed that EPA's updated approach to RULOF

> will improve consistency in EPA's plan reviews across states and sources and provide greater regulatory certainty. They will also prevent some states from undercutting the efforts of others and undermining the overall effectiveness of section 111(d) rules by offering variances on lenient terms. In addition, the proposed revisions will furnish EPA with a clear framework for reviewing variances in state plan submissions, thus speeding approvals or disapprovals, enhancing consistency, and reducing the number of court challenges. Perhaps

[111] The agency also asserts that the frequent starting and stopping associated with low-load activities could erase some of the benefits of highly efficient turbine, but provides no data to support the notion that it would not be environmentally beneficial to require the more efficient technology.

> most importantly, these guardrails will help ensure that full adherence to EPA's emission guideline is the general rule for existing sources, and that variances allowing less effective standards are the rare exception.[112]

The RULOF provisions that appear in the Proposed Rule generally display these same virtues. On the one hand, these provisions faithfully execute section 111(d)'s requirement that EPA "permit [each] State in applying a standard of performance to any particular source … to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." 42 U.S.C. § 7411(d). On the other hand, they help ensure that variances based on remaining useful life are not commonplace but instead limited to uniquely situated sources that reflect "fundamental differences" from typical cases, 88 Fed. Reg. at 33,382, and that such variances do not undermine the overall effectiveness of EPA's emission guidelines.

Several aspects of the RULOF provisions specific to this rulemaking are worth highlighting. First, for coal-fired steam EGUs, the proposed emission guidelines establish subcategories (and corresponding emission reduction obligations) that themselves are tiered to sources' remaining useful lives. This largely obviates the need for variances based on remaining useful life, as sources' baseline standards of performance will already reflect the kinds of emission reductions that should be expected based on each source's anticipated retirement date. At the same time, it is crucial to emphasize that this does not limit states' opportunities to approve variances for existing coal units in the rare circumstances where a source can, in fact, demonstrate the kinds of "fundamental differences" that would justify one. As EPA notes, although the agency does "not anticipate that states would be likely to demonstrate the need to invoke RULOF based on a particular coal-fired EGU's remaining useful life … *doing so is not prohibited under these emission guidelines*." *Id.* at 33,833 (emphasis added). Thus, with regard to existing coal units in rare circumstances, EPA has remained faithful to the requirements of section 111(d) while at the same time minimizing the circumstance in which any particular source might have difficulty complying with the applicable standard due to remaining useful life.

Additionally, in describing the kinds of "fundamental differences" that would justify a variance in the context of the Carbon Pollution Standards, EPA suggests that a mere showing of higher compliance costs than average would not, in itself, suffice. Instead, the agency indicates that variances are only appropriate for true "outlier" cases, where the source's financial burden would be "greater than the 95th percentile of costs on a fleetwide basis (assuming a normal distribution)." *Id.* at 33,833. It is not clear whether EPA proposes to establish the 95th percentile standard as formal applicability threshold for RULOF-based variances, but Joint Environmental Commenters believe this is a wholly appropriate cut-off point for weeding out the more typical deviations from the mean and identifying the kinds of true cost outliers for which RULOF-based variances may be appropriate. EPA should therefore formalize this 95th percentile demonstration as a requirement for sources seeking a variance based on costs. In addition, as discussed in the environmental group comments on the implementing

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[112] Sierra Club, Earthjustice, et al., *Comments on Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)*, Dkt. No. EPA-HQ-OAR-2021-0527-0099 (Feb. 27, 2023), https://downloads.regulations.gov/EPA-HQ-OAR-2021-0527-0099/attachment_1.pdf, included as Exhibit 38.

regulations proposal,[113] EPA should clarify that the "fundamental differences" criteria apply to *all* variance requests regardless of rationale, not just those based specifically on a unit's remaining useful life.

EPA is also correct to prohibit states from establishing a more lenient standard for a source based on RULOF considerations if the source can reasonably achieve the baseline standard through some compliance pathway other than the BSER. 87 Fed. Reg. at 33,383. This is simply common sense: standards of performance are numerical emission reduction obligations, not commands to implement any particular technology. If a source can feasibly implement some technology that will allow it to meet the standard, then no variance should be forthcoming, regardless of whether that technology is the same as EPA's "best system." Joint Environmental Commenters also support EPA's decision not to specify any "imminent" retirement dates for which a source may qualify for a BAU standard. The guidelines already provide BAU standards for coal plants with imminent and near-term retirement dates, and emission reduction obligations for existing combustion turbines do not take effect until 2032. (As discussed previously, however, we urge EPA to define BAU standards as those reflecting each source's 95th percentile lowest rolling annual average over the previous decade, rather than whatever happens to be its current emission rate.)

EPA should, however, consider establishing outmost dates beyond which sources cannot receive variances based on remaining useful life, particularly for combustion turbines and long-term steam EGUs. By doing so, EPA can help preempt inappropriate variance requests at the outset and streamline the plan approval process. Conversely, the agency should *not* provide any presumptively approvable standard, criteria, or analytic approach for units seeking variances. *See id.* at 33,384. The very premise of source-specific variances is that they reflect circumstances that are unique to a particular unit and fundamental differences from the general case. It is therefore inappropriate to offer any sort of generic rubric for approving variances separate from the particularized facts of each case. On the contrary, Joint Environmental Commenters strongly support EPA's decision to place the burden of justifying any variance squarely on the state, and to require any such showing to be "based on information from reliable and adequately documented sources and be applicable to and appropriate for the affected facility." *Id.* at 33,384. Any presumptively approvable variance would undermine this requirement, which is designed to safeguard the integrity of the EPA's selection of the BSER.

Joint Environmental Commenters are also concerned that EPA has, in its proposed revisions to the section 111(d) implementing regulations, added "technical infeasibility" alongside "physical impossibility… of installing necessary control equipment" in the text of section 40 C.F.R. § 60.24a(e)(2), potentially expanding the circumstances that would permit a variance. As explained in the environmental group comments, "'[t]echnical infeasibility' is a highly imprecise term that is susceptible to abuse and overapplication;" it "is not needed as an independent criterion if EPA clarifies that a source may receive a variance only for technological differences that EPA did not consider in establishing the emission guideline for the source category or subcategory and that give rise to fundamentally unreasonable costs."[114] Although EPA is not taking comment on the implementing regulations proposal in this rulemaking, we urge it to supersede this requirement in the

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[113] *Id.* at 10–11.
[114] *Id.* at 11.

context of the Carbon Pollution Standards. At a very minimum, the agency should provide further clarity on the meaning of "technical infeasibility" and define it in the most limited manner possible. Joint Environmental Commenters strongly support EPA's requirement that for any variance a state grants, it must "consider the potential pollution impacts and benefits of control to communities most affected by and vulnerable to emissions from the affected EGU in determining source-specific BSERs and the degree of emission limitation achievable through application of such BSERs." 88 Fed. Reg. at 33,386. In the December 2022 proposal, EPA explains that states may, by way of such an analysis, provide a more protective standard for the source in question than would otherwise by the case:

> If the comparative analysis shows that a designated facility may be controlled at a certain cost threshold higher than required under the EPA's proposed revisions to the RULOF provision, and such control benefits a vulnerable community that would otherwise be adversely impacted by a less stringent standard, the state in accounting for RULOF could use that cost threshold to apply a standard of performance.

87 Fed. Reg. at 79,203. We believe, though, that this provision should be strengthened in the context of the current rulemaking. Because of heavy pollution burden that fossil fuel-fired EGUs place on historically disadvantaged communities, EPA must clarify that states *must* (not merely *may* or *should*) establish a more protective standard for sources receiving a variance if the comparative analysis would show that failure to do so would adversely impact community health.

Finally, we fully support EPA's determination that section 111(d) permits states to include more stringent pollution limits in their plans than would be required under the agency's corresponding emission guidelines, and that such plans remain federal enforceable. However, we believe this is the case regardless of section 111(d)'s RULOF provision: the structure and text of section 111(d) itself, as well as other Clean Air Act provisions, make this clear. As discussed in Section II, the entire purpose of section 111 is to achieve *maximal*, not merely serviceable, emission reductions. Moreover, Congress expressly preserved state authority to issue air pollution standards that are more stringent than the emission limits included in a section 111(d) guideline. 42 U.S.C. § 7416. To permit more protective state-based standards but strip them of federal enforceability in the context of a section 111(d) plan would be absurd: EPA would be obligated to reject any such plan as not "satisfactory," 42 U.S.C. § 7411(d)(2)(A), and would issue a federal plan for sources in that state providing a parallel set of less stringent (but federally enforceable) standards to co-exist alongside the more stringent state requirements. Sources would then need to show compliance with both sets of standards. Congress could not possibly have contemplated such an arrangement.

Indeed, the Supreme Court reached this exact conclusion with regard to section 110 state implementation plans under the national ambient air quality standards (NAAQS) program, which Congress expressly used as the structural model for section 111(d). *See* 42 U.S.C. 7411(d)(1) (directing the Administrator to establish a regulatory framework for section 111(d) that is "similar to that provided by section 7410 of this title"). In *Union Electric Co. v. EPA*, 427 U.S. 246, 261–66 (1976), the court held that the agency has no authority to disapprove a state implementation plan solely because it exceeds the minimum requirements for timely attaining compliance with EPA's NAAQS. The Court there held that the most natural reading of section 110 "is simply that the

Administrator must assure that the minimal, or 'necessary,' requirements are met, not that he detect and reject any state plan more demanding than federal law requires." *Id.* at 263. The Court further held that prohibiting states from finalizing more protective plan would

> not only require the Administrator to expend considerable time and energy determining whether a state plan was precisely tailored to meet the federal standards, but 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 Amendments for visiting such wasteful burdens upon the States and the Administrator, and so we reject the argument of Amici.

Id. at 264. There is no meaningful difference between section 110 SIPs and section 111 state plans in this regard, and the logic of *Union Electric* applies with full force to the Proposed Rule. Thus, federally enforceable state plans may already include standards that are more protective than EPA's emission guidelines, and the agency need not use the RULOF provision to authorize such plans.

XI. TRADING AND AVERAGING.

A. EPA Should Not Allow Trading and Averaging as a Compliance Option in State Plans.

EPA requests comment on whether, to what extent, and in what way trading and averaging between sources should be permitted under state plans implementing the Carbon Pollution Standards. 88 Fed. Reg. at 33,392–96. Joint Environmental Commenters urge EPA *not* to allow trading as a compliance option in state plans. Nothing in section 111(d) obligates the agency to permit averaging and trading in state plans for any particular rulemaking. Unlike section 110's NAAQS program, which expressly allows for "economic incentives such as fees, marketable permits, and auctions of emissions rights" in state implementation plans, 42 U.S.C. § 7410(a)(2)(A), section 111(d) includes no such language.

In its 111(d) implementing regulations proposal, EPA asserts that "section 111(d) *authorizes* [it]"—but does not *require* it—to approve state plans that "achieve the requisite emission limitation through aggregate reductions from their sources, including through trading or averaging," and only then where it is "appropriate for a particular emission guideline and consistent with the intended environmental outcomes of the BSER." 87 Fed. Reg. at 79,208 (emphasis added). In the context of the proposed Carbon Pollution Standards, trading or averaging programs would not be "appropriate:" they would necessarily provide certain geographic areas and their associated communities with *more* reductions of harmful pollutants emitted by power plants than would occur in the absence of trading, while providing other geographic areas and communities with *fewer* emission reduction benefits—and potentially even emission increases.

Even while CO_2 mixes evenly in the atmosphere, EPA must not only consider distributional impacts of the target pollutant of a particular regulation (CO_2 in this case); it must address secondary environmental impacts as well. *See United States Sugar Corp. v. EPA*, 830 F.3d 579, 625 (D.C. Cir. 2016) (finding that EPA's "consider[ation] [of] co-benefits" when establishing section 112 air toxics standards "is consistent with the CAA's purpose" and thus permissible). As Sierra Club and Earthjustice explained in comments submitted to the agency in 2020, "[w]hen the EPA exercises its

Clean Air Act authority to limit a particular air pollutant, the effects of that action on other air pollutants is … an 'important aspect of the problem" that the agency must address."[115] In practical terms, this means that if a trading or averaging program for CO_2 emissions were to result in no distributional concerns with regard to the primary pollutant, but would create distributional inequities due to other pollutants such as NO_x and $PM_{2.5}$ emitted by that source category, it would not be "appropriate." That is precisely the case here.

As EPA well understands, the burdens of pollution have historically fallen, and continue to fall, disproportionately on communities of color and low-income communities, who often experience overlapping and cumulative impacts from multiple environmental and public health crises. This Administration has rightly placed much emphasis on working to ameliorate these patterns, and must pay attention to how state plans under section 111(d) would affect them. Given that the purpose of section 111 is to establish standards of performance for sources that "cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare," EPA must govern the implementation of section 111 standards so as to consider the health and welfare of those who are currently most harmed by pollution, rather than focus solely on aggregate-level impacts. Indeed, it would be arbitrary and capricious for EPA *not* to consider distributional effects of section 111(d) implementation. And, under Executive Orders 14,096[116] and 12,898,[117] the agency must tailor such policies in a way that reduces distributional inequities. Because trading or averaging under this program would likely *increase* distributional inequities, EPA must not permit these compliance avenues.

B. Trading Programs to Implement the Proposed Emission Guidelines Will Impose Unjustified Environmental and Administrative Costs.

It is not difficult to envision ways in which a state-implemented trading program under this rule could exacerbate environmental justice concerns. Suppose, for instance, two coal plants subject to retirement dates in the late 2030s are both subject to an emission standard that reflects co-firing 40 percent gas alongside coal, and that the first plant is located near an environmental justice community while the second is located near a wealthier and more privileged community. Suppose, further, that the first plant continues to emit unabated until its retirement and complies with its standard by

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[115] Earthjustice, et al., *Comments on the EPA's May 14, 2021 Interim Final Regulation Rescinding the Rule on Increasing Consistency and Transparency in Considering Benefits and Costs in the Clean Air Act Rulemaking Process (Docket ID No. EPA-HQ-OAR-2020-0044)*, 27 (Aug. 3, 2020) (quoting language from *Motor Vehicle Mfrs. Ass'n of the U.S., Inc. v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43 (1983)).
[116] 88 Fed. Reg. 25,251, 22,253 (Apr. 26, 2023) (requiring, in section 3(1) of the E.O., that each federal agency "identify, analyze, and address disproportionate and adverse human health and environmental effects (including risks) and hazards of Federal activities, including those related to climate change and cumulative impacts of environmental and other burdens on communities with environmental justice concerns").
[117] 59 Fed. Reg. 7,629, 7,629 (Feb. 11, 1994) (requiring, in section 1-101 of the E.O., that "each Federal agency shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income population").

purchasing credits from the other plant, which co-fires 80 rather than 40 percent gas. Although the net CO_2 reduction benefits are broadly distributed due to the science of greenhouse gas intermixture and climate change, the environmental justice community near the first plant will receive *no* benefits of reduced mercury, SO_2, and NO_x pollution that would occur if the plant had actually satisfied its CO_2 standard. The more privileged community, on the other hand, will receive *extra* emission reduction benefits than it would have in the absence of the trading program, without which the second plant would not have the same incentives to overcomply with the 40 percent co-firing standard.

Furthermore, the putative benefits of trading or averaging (i.e., greater economic efficiencies) are not, in this case, worth the burdens of overseeing and administering these kinds of programs. As EPA notes in the preamble, the number of sources that might be eligible for trading or averaging in the first place will probably be exceedingly small. The agency is proposing to prohibit coal steam units in the imminent-term and near-term retirement subcategories from benefiting from trading, as well as oil and gas steam units. 88 Fed. Reg. at 33,393. This makes sense: these units will already be subject to standards that require no further emission reductions, and certainly should not be permitted to *exceed* their recent historical emission rates by way of credits. The same is true for sources subject to a RULOF-based variance: EPA sensibly precludes these units from receiving credits since they will already receive a less stringent standard. *Id.* at 33,393–4. Nor are any of these sources likely to generate credits: owners and operators will not seek to invest in further emission-reduction opportunities for any of them absent regulatory pressure. To the extent such opportunities *are* broadly available, EPA should incorporate them into the emission guidelines for these subcategories.

EPA correctly notes that it makes little sense to include long-duration coal units equipped with CCS and existing gas turbines in a trading program. 88 Fed. Reg. at 33,394. This is because units deploying CCS, which are eligible for tax credits based on the quantity of CO_2 captured, are unlikely to respond to the same incentives that might be provided by trading. *Id.* Furthermore, because the standard for these units reflects 90 percent capture, sources will have limited opportunity to capture still more carbon and thus generate credits through overcompliance. The same is true for existing combustion turbines implementing CCS at a 90 percent capture requirement starting in 2032 as well as those co-firing 96 percent natural gas in 2038. Accordingly, this would leave only medium-term coal-fired units (i.e., those subject to a gas co-firing BSER) and existing combustion turbines during Phase 2 available for a trading program. The number of units meeting these criteria will likely be few, with little net economic gain to the system. On the other hand, any trading that any that does occur across these units will entail an uneven distribution of pollution reductions, reducing the health benefits that certain impacted communities would otherwise receive.

In addition to the necessarily limited scope and paltry economic benefits of any such program, EPA must also consider the administrative burden on EPA in reviewing and approving state-developed trading programs, as well as the burden on states themselves in implementing them. As EPA notes, trading programs require "establishing compliance timeframes and the mechanics for demonstrating compliance under the program (e.g., surrender of compliance instruments as necessary based on monitoring and reporting of CO_2 emissions and generation); establishing requirements for continuous monitoring and reporting of CO_2 emissions and generation; and developing a tracking system for tradable compliance instruments." *Id.* at 33,395. All told, trading programs in under state plans implementing the Carbon Pollution Standards will simply not be worth the substantial downsides, both in terms of environmental impacts (i.e., increased distributional inequities) and administrative costs. We therefore urge EPA to prohibit trading altogether in the final rule.

C. If EPA's Final Rule Permits States to Establish Trading or Averaging Programs, it Must Establish Crucial Safeguards to Prevent Environmentally Damaging Outcomes.

If EPA nevertheless authorizes trading or averaging programs under the Carbon Pollution Standards—and it should not—it must take multiple steps to minimize negative environmental, health, and justice impacts. ***First***, EPA must ensure that trading or averaging programs do not result in or exacerbate distributional inequities with regard to air pollution, nor deny overburdened communities the full benefit of emission reductions anticipated under the rule. States state seeking to establish a trading or averaging program must present an analysis thoroughly demonstrating that such distributional inequalities will not occur. EPA must also strictly enforce the requirement that states engage in "robust and meaningful"—not merely perfunctory—engagement with stakeholder communities, 88 Fed. Reg. at 33,398 including providing broad opportunity for the public to review and comment on such analysis before any final conclusion regarding distribution inequities is reached. If members of overburdened stakeholder groups express opposition to potential distributional impacts of a proposed trading program, EPA should reject the plan. In addition, if it permits trading or averaging, EPA must establish spatial restrictions (i.e., flow controls) for any trading or averaging program. These restrictions can ensure that plants in areas with high pollution, or those populated by overburdened communities, can *create* and *sell* emission credits through overcompliance but cannot comply by *receiving* or *purchasing* credits.

Second, EPA must ensure that credits are only tradeable between sources within the same subcategory. To reiterate our discussion in the previous subsection, it appears as though trading could only conceivably occur among medium-term coal units and existing combustion turbines at Phase 2. Particularly if EPA were to approve a program that allowed for trading more broadly, significant problems could result if sources were permitted to trade credits across subcategories. This is a especially true for EGUs equipped with CCS. Under the current proposal, coal units in the long-term subcategory will be subject to a standard based on 90 percent capture of CO_2. Suppose that such units are permitted to trade credits with one another, but not within units in other subcategories. Because such plants cannot capture substantially more CO_2 than 90 percent, any overcompliance (and thus credits generated within the system) will be minimal. Accordingly, even units receiving credits will be required to capture *near* 90 percent of their CO_2.

Suppose, though, that such units could comply by receiving credits from units in the co-firing subcategory. Because coal units *can* burn substantially more than 40 percent gas, the opportunity for credit generation is much greater. But if long-term coal units could acquire large quantities of credits generated by co-firing units, they could meet their remaining emission reduction obligations through (as opposed to full or nearly-full) carbon capture. Because of the way in which the IRA's tax credit provisions are structured, this could perversely allow some units to emit much *more* net CO_2 (albeit at a lower lb/MWh rate) than they did before retrofitting with capture technology. This phenomenon, which is discussed in a paper commissioned by Sierra Club and produced by Synapse Energy

Economics, Inc,[118] would largely defeat the purpose of the Carbon Pollution Standards. This is just one example of the kind of problem that could result from permitting trading across subcategories.

Third, if EPA permits rate-based trading, it must not permit sources that operate at rates below the applicable legal standard to generate even more credits by operating above their historic/baseline capacity factors. While the Supreme Court held in *West Virginia v. EPA* that the agency may not premise a "best system" determination directly on existing coal or gas plants' reduced utilization, 142 S.Ct. at 2612, nothing in the opinion suggests that EPA must permit compliance flexibilities in state plans that incentivize sources to *increase* their utilization. Conversely, under mass-based trading programs, EPA must not let sources to generate emission allowances through reduced operations (relative to the sources' historic/baseline capacity factors) or premature retirement. To allow such units to generate allowances through reduced utilization would grant an environmentally detrimental windfall to sources that receive them. Many aging units will likely undergo declining capacity factors in any event over the course of the compliance period, and some may utilities may decide to shutter old units before their federally-enforceable retirement date due to the changing economics of the electric sector that favors renewable resources. These units should not receive additional benefits—which would allow other sources to emit more CO_2—for what would essentially have been business-as-usual behavior.

Fourth, EPA should not permit sources to bank credits earned in one year for use in a future compliance year. EPA suggests that banking "may provide incentives for early emission reductions, promote operational flexibility and planning, and facilitate market liquidity." 88 Fed. Reg. at 33,406. Yet any early emission reductions achieved through banking would necessarily be offset by later emission increases when those banked credits are used for compliance purposes in subsequent years. This serves no environmental benefit: because GHGs accumulate in the atmosphere, what matters are *total* emission reductions, not *early* reductions that would be negated a few years later. Permitting banking could also result in greater swings in sector-wide emissions from one year to the next, which would frustrate policymakers and utilities' environmental planning efforts. Any additional operational flexibilities do not justify banking in light of these downsides.

Fifth, EPA should not permit interstate trading. As the agency notes, states wishing to join together in a shared program

> would need to, at a minimum, use the same form of trading and have identical trading program requirements. There are many requirements for program reciprocity and approvability that would need to be established in the emission guidelines, in addition to providing mechanisms for submission and EPA review of State plans that include interstate trading mechanisms.

[118] Pat Knight and Jack Smith, Synapse Energy Economics, Inc., *Clearing the Air on Coal CCS: New tax credits make partial CO_2 capture viable, potentially increasing emissions* (Oct. 21, 2022), https://www.synapse-energy.com/sites/default/files/Clearing-the-air-on-coal-CCS-22-100.pdf, included as Exhibit 39.

88 Fed. Reg. at 33,381. Simply put, any supposed benefits from interstate trading would not be worth administrative burden on both EPA and state governments of developing, submitting, reviewing, approving, overseeing, and facilitating such a program. The main purpose of interstate trading would be to expand the universe of sources that could trade with one another, ostensibly maximizing the efficiencies of the credit/allowance market. Yet more trading always creates a greater risk of distributional inequities and lower net emission reductions than would occur in the absence of trading. The agency and states should not spend additional staff time and resources simply to grant sources the largest possible market in which to trade.

Sixth, EPA seeks comment on the potential benefits of an averaging regime. To the extent that EPA permits averaging, it should limit it to co-located sources. That is, if a company owns a single facility with multiple EGUs emitting pollution either from a single stack or from multiple stacks at the same physical location, averaging is less likely to result in distributional inequities than if permitted among physically distant sources. Even within a single facility, however, averaging could depress total emission reductions if units that would otherwise have overcomplied with the standard even in the absence of averaging could, through averaging, lessen the emission reduction requirements of co-located units. In addition, EPA refers to a specifically "gross generation-based weighted average" across multiple sources as one possible means of compliance. As discussed in Section V, EPA must establish emission rates based solely on net generation, which—unlike gross generation—is environmentally relevant.

Finally, EPA asks whether existing state trading programs should be permitted as a mean of compliance. None of these programs foreclose the kind of distributional inequities we have discussed, and should thus not be permitted to serve as compliance options. More generally, our concerns about trading in general and about the administrative feasibility of coordinating interstate programs under the rubric of section 111 state plans persuade us that, even if EPA does permit trading or averaging in state plans (and again, it should not), it should prohibit states from relying on pre-existing programs rather than satisfying the specific criteria described above. Furthermore, none of these existing state programs correspond neatly (let alone exactly) with EPA's proposed emission guidelines in terms of the various requirements and regulatory details. It would likely be impossible to shoehorn such a program into a section 111 state plan (or, more accurately, group of state plans) without either requiring substantial changes to the existing program or permitting deviances from EPA's requirements that apply to all other state plans. For these reasons, we urge EPA not to permit this option.

XII. CONSIDERATIONS REGARDING AFFECTED COMMUNITIES AND OTHER STAKEHOLDERS.

A. EPA Must Do More to Ensure that the Community Engagement Required by the Proposed Rule Is Truly Meaningful.

In its Proposed Rule, EPA emphasizes the importance of meaningful engagement with stakeholders. The agency notes that the meaningful engagement of impacted communities in the development, implementation, and enforcement of regulations is central to its definition of environmental justice. 88 Fed. Reg. at 33,412. Executive Order 14,096, "Revitalizing Our Nation's Commitment to Environmental Justice" states, among other things, that "all people should be afforded the opportunity to meaningfully participate in agency decision-making that may affect the health of their community or environment" and asserts that this is particularly true for communities with environmental justice concerns. 88 Fed. Reg. at 22,252.

EPA's proposed definition of meaningful engagement is articulated in the 111(d) implementing regulations proposal discussed previously:

> Meaningful engagement means the timely engagement with pertinent stakeholder representation in the plan development or plan revision process. Such engagement must not be disproportionate in favor of certain stakeholders. It must include the development of public participation strategies to overcome linguistic, cultural, institutional, geographic, and other barriers to participation to assure pertinent stakeholder representation, recognizing that diverse constituencies may be present within any particular stakeholder community. It must include early outreach, sharing information, and soliciting input on the state plan.

87 Fed. Reg. at 79,191. The implementing regulations proposal further states that "pertinent stakeholders include, but are not limited to industry, small businesses, and communities most affected by and/or vulnerable to the impacts of the plan or plan revision." *Id.* (cleaned up).

While Joint Environmental Commenters support EPA's emphasis on removing barriers to stakeholder engagement, the Proposed Rule fails to ensure that this engagement is *meaningful*, particularly for impacted and overburdened communities. EPA must guarantee that these engagement processes affect agency and state decisionmaking, including state plan development processes and permit determinations.[119] In addition, EPA should do more to address barriers that environmental justice communities face to effective participation, including by expanding the scope of required engagement activities and by making rule requirements more explicit and prescriptive.

1. **To be meaningful, community engagement must help advance decisions that incorporate and materially address community expertise and perspectives.**

The Proposed Rule focuses almost exclusively on the process and preconditions for meaningful community engagement, including ensuring that impacted communities receive timely notice of proposed actions and have access to pertinent information. Addressing barriers and promoting transparency are critical, but meaningful community engagement must address community concerns and create better, more just outcomes. This essential link between process and outcomes is recognized in E.O. 14,096, which states that environmental justice "can successfully occur *only through* meaningful engagement and collaboration with underserved and overburdened communities *to address* the adverse conditions they experience and ensure they do not face additional disproportionate burdens of underinvestment." 88 Fed. Reg. at 25,251 (emphasis added).

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[119] *See* The Tishman Environment and Design Center at The New School, et al., *Comments on New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 33 (Aug. 8, 2023).

For example, prior to publishing the Proposed Rule, EPA engaged in stakeholder outreach with a focus on members of environmental justice communities. During this outreach, residents of these communities

> voiced two primary concerns [to EPA]. First, there is the concern that their communities have experienced historically disproportionate burdens from the environmental impacts of energy production, and second, that as the sector evolves to use new technologies such as CCS and hydrogen, they may continue to face disproportionate burdens.

88 Fed. Reg. at 33,412. However, EPA's proposal is, in its current state, projected to perpetuate the *status quo* at best with regard to distribution inequities. With respect to existing air pollution disparities in environmental justice communities, EPA states that

> [w]e infer that baseline disparities in the ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the regulatory action or alternatives under consideration. …This EJ assessment also suggests that these actions are unlikely to mitigate or exacerbate $PM_{2.5}$ exposures disparities across populations of EJ concern analyzed.

Id. at 33,413. Indeed, as we discuss more in Section XII.B below, the rule is anticipated to provide an uneven distribution of pollution reduction benefits, and will likely *increase* criteria pollutant emissions for large numbers of people, possibly including EJ populations in some cases. EPA responds by affirming that it will "continue[] to consider ways of protecting [environmental justice communities] from adverse public health and environmental effects of air pollution." *Id.* at 33,412. EPA also states that it "expects that states will address facility-specific concerns about how to responsibly deploy CCS and any other potential control strategies in the course of meaningful engagement under the proposed emission guidelines for existing steam generating units and existing combustion turbines." *Id.* at 33,414. These vague assertions are insufficient.

EPA must do more to ensure that meaningful engagement leads to the greatest possible outcomes for EJ communities. In the final rule design, the agency must make the greatest possible efforts not merely to "consider" EJ outcomes and distributional equities, but to actually provide emission reduction benefits that *reduce*, rather than maintain or exacerbate, the pollution burdens that these communities face. EPA must also explicitly direct states to do the same in the context of plan development, and must review those plans accordingly. In addition, in its final rule, EPA should include a clear mechanism for EJ communities to intervene in the regulatory processes for state plans and permits, as well as clear criteria for denying plans and permits that would risk harming human health or contributing to cumulative burdens in EJ communities, including plans and permits related to plants co-firing hydrogen or installing CCS.[120]

[120] See *id.* (recommending that "meaningful engagement" explicitly include the ability of EJ communities to intervene in the regulatory process to deny a proposed state plan or a permit related to a CCS or hydrogen co-firing facility when there are risks that may be detrimental to human health and/or will make absolute contributions to cumulative impacts).

EPA should also require that states and owner/operators do more than simply summarize stakeholder input received. EPA should instead require that they describe specific comments and questions received, provide a written public response to them, and detail how final decisions were affected or modified as a result of such input. This is essential if EPA intends to build trust in its processes, including by demonstrating to community members that their comments are being taken seriously.

2. EPA must do more to eliminate barriers to meaningful engagement.

As noted above, eliminating barriers to meaningful engagement—albeit insufficient on its own—is necessary. There are a number of additional requirements EPA can and must establish to achieve this goal. These include promulgating more specific and prescriptive requirements around key issues such as notice, hearings, and information to be provided, and addressing what is most often the greatest barrier to meaningful community engagement: the highly technical and inaccessible way that critical information related to the planning and permitting processes is presented. Community groups and residents often lack the resources to retain technical experts who can help them meaningfully analyze and respond to information generated in the permitting process. As a result, community engagement opportunities in permitting and planning decisions often feel tokenistic or performative, undermining trust in EPA and its processes. Overcoming this barrier is essential to ensuring meaningful engagement.

Many of the recommendations offered in this section are informed by recent efforts of climate and environmental justice advocates, as well as government actors, in Massachusetts. Beginning in 2021, the Massachusetts Attorney General's Office ("AGO") convened a Stakeholder Working Group ("SWG") with members from environmental and climate justice advocacy groups[121] to discuss barriers to participation in energy regulatory proceedings. The group convened regularly for almost two years, and in May 2023, its work culminated in the release of the report *Overly Impacted & Rarely Heard: Incorporating Community Voices into Massachusetts Energy Regulatory Processes*,[122] which provides recommendations for improving the energy regulatory process as Massachusetts moves toward a decarbonized energy future. The report was informed by input from public surveys, interviews, and multiple focus groups, all of which provided valuable insight into the public perception and understanding of energy regulatory processes.

Also in 2021, the Massachusetts Department of Public Utilities opened an inquiry on its own motion into procedures for enhancing public awareness of and participation in its proceedings. In this matter, climate and environmental justice advocates have provided insights on how the agency can make

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[121] The SWG participants included GreenRoots, National Consumer Law Center, Massachusetts Climate Action Network, Alternatives for Community & Environment, Regulatory Assistance Project, Conservation Law Foundation, Vote Solar, and Environmental Defense Fund. Support was also provided by Strategy Matters and Neighbor to Neighbor.

[122] Mass. Atty. Gen., *Overly Impacted & Rarely Heard: Incorporating Community Voices into Massachusetts Energy Regulatory Processes* (hereafter "SWG Report") (May 2023), https://www.mass.gov/doc/overly-impacted-and-rarely-heard-incorporating-community-voices-into-massachusetts-energy-regulatory-processes-swg-report/download, included as Exhibit 40.

proceedings more accessible for the public to understand both the nature and impact of project applications and encouraging public reactions to such project applications.

One significant lesson that emerged from these processes is that agencies, such as EPA, must identify barriers to meaningful engagement with particularity and then identify specific procedural steps and requirements for public engagement. It is critical for EPA to assume that a significant number of state and industry actors will do the bare minimum of what is required of them and interpret vague or aspirational directives in the narrowest possible terms.

i. EPA must incorporate additional requirements to ensure that impacted communities receive timely notice of decision-making processes.

Through its process, Massachusetts's SWG found that members of the public want more transparency in proceedings so that they can more easily participate in and influence them. This desire is also reflected in E.O. 14,096, which notes that critical aspects of community engagement include "providing timely opportunities for members of the public to share information or concerns and participate in decision-making processes" and "providing notice of and engaging in outreach to communities or groups of people who are potentially affected." 88 Fed. Reg. at 25,254. While EPA similarly makes timely engagement a general directive in its Proposed Rule, it must do more to ensure that such engagement happens in an effective and not perfunctory manner.

One way to improve efficiency and ensure meaningful engagement is to require pre-filing community engagement notices before a project filing comes before the agency and before a state publishes its section 111(d) plan. Such a step would be in addition to the stakeholder engagement required *after* draft plan publication. Another step EPA should consider to ensure that impacted communities have timely knowledge of proceedings and a general understanding of the regulatory framework is to require the establishment of a community advisory group to participate within both state planning proceedings and proceedings around specific facilities.

EPA should also offer more specific directives around notice. In the 111(d) implementing regulations proposal, EPA requires "the development of public participation strategies to overcome linguistic, cultural, institutional, geographic, and other barriers to participation to assure pertinent stakeholder representation," providing that such strategies "must include early outreach, sharing information, and soliciting input." 87 Fed. Reg. at 79,191. For the Proposed Rule to be effective, EPA must further articulate, as much as is feasible, specific strategies to be employed, the timing of outreach to ensure that it is sufficiently "early," and the manner in which information should be shared to ensure that impacted communities can access and understand it. Examples of this kind of detail are offered in the preamble to the implementing regulations proposal, but EPA must provide it in the regulatory text of the final Carbon Pollution Standards and include more explicit direction.

To ensure proper notice, EPA should require that project proponents and planning agencies post language-appropriate materials in gathering spaces that are commonly visited by the public. This should include places of worship, community and senior centers, grocery stores, schools, laundromats, post offices, bus and train stations, and large multi-unit residential buildings. Such notices should be printed on brightly colored paper and written in large text to draw attention. EPA should also require that notice be provided to municipal legislative bodies, municipal regional and planning commissions, local elected officials, tribal-serving organizations and tribal communities (both council and programs as well as members), and small businesses in impacted areas both because of their interest in these matters and because of their ability to identify community-based organizations that should receive public notice. This outreach process should include building relationships with environmental justice communities and organizations using trusted advocates to foster open and respectful communication in order to better understand and apply community-specific best practices.

EPA must also direct regulated entities to take advantage of social media as a tool to provide notice. In addition to publication on the project proponent's social media,[123] the agency should require that information be shared with other parties that have connections with impacted community members so that they can also amplify it via social media and other available channels. This should include municipal bodies, elected officials, community-based organizations, and other local institutions. News outlets also typically have associated social media accounts where notice can be published. On social media, as with other formats, the notice document should be translated into the appropriate languages for the communities expected to be affected by the activity.[124]

EPA should also create, and require states and regulated entities to create, electronic distribution lists so that notice of key proceedings and compliance activities are provided to members of the public who indicate an interest in receiving it. EPA can maintain a list of its own that enables climate and environmental justice organizations to receive timely notice and reach out to smaller chapters and local or regional partners when a proceeding that impacts them arises. States and industry actors should also be required to do this so that residents and organizations interested in specific sites are kept informed in a meaningful way. This will significantly advance the goals of effective notice and transparency while requiring states and industry to take the very simple step of maintaining e-mail distribution lists.

ii. EPA must ensure that impacted communities have the technical assistance needed for meaningful engagement and must require that state and industry actors provide key information as accessibly as possible.

E.O.14,096 recognizes that community engagement cannot be meaningful if community members lack the resources and capacity to understand, analyze, and effectively respond to the information they are provided. To address this, the E.O. calls upon agencies to "provid[e] technical assistance, tools, and resources to assist in facilitating meaningful and informed public participation, wherever practicable and appropriate." 88 Fed. Reg. at 25,254. EPA's current Strategic Plan similarly sets the goal that "by September 30, 2026, all EPA programs that seek feedback and comment from the public will provide capacity-building resources to communities with environmental justice concerns to support their ability to meaningfully engage and provide useful feedback to those programs."[125] In addition to providing available technical assistance resources to overburdened communities, EPA should require that states and industry actors provide resources for communities to access

[123] SWG Report at 33, 38, 71.
[124] SWG Report at 32.
[125] EPA, *FY 2022-2026 EPA Strategic Plan*, at 30 (Mar. 2022), https://www.epa.gov/system/files/documents/2022-03/fy-2022-2026-epa-strategic-plan.pdf.

independent technical assistance.

Like President Biden and EPA, members of Massachusetts' SWG noted that interested persons needed to expend a significant amount of time and resources to gain a working knowledge of energy proceedings due to their technical complexity. Accordingly, the SWG issued a number of recommendations that EPA should require in addition to technical assistance resources. These include requiring non-technical, plain language summaries of documents in proceedings, requiring that industry websites be easily accessible (which we discuss more fully below), requiring staff to be available to answer questions and provide explanations to members of the public, and requiring free access to transcripts.[126]

Given the voluminous documentation typically involved in these proceedings, EPA should require that any summaries provided emphasize in accurate and accessible language the information that is typically of greatest community concern, including the regulatory requirements and limitations that regulated entities are subject to, the environmental impacts of proposed actions and of existing facilities, and any ways in which regulated entities are out of compliance. In addition, states and entities should be required to provide documents that accessibly explain how planning and permitting processes work, the issues they must consider and obligations they must satisfy, and the role of public comment and community input in these proceedings—both how it is to be solicited and received and what entities are obligated to do with comments provided. These requirements are important for advancing environmental justice, and are also discussed in the recently published White House Memorandum *Broadening Public Participation and Community Engagement in the Regulatory Process*. This document notes that meaningful engagement is undermined by a lack of trust in government and a commonly held belief that agencies do not take public comments, personal experiences, and other information provided by community members seriously.[127] The elements described above can help counteract those phenomena and foster greater trust between affected communities and regulators.

iii. EPA should adopt more specific requirements related to overcoming language barriers to meaningful engagement.

EPA should develop language access protocols[128] and require and set thresholds for translation of public notices and interpretation of hearings wherever an impacted community includes populations historically burdened by energy infrastructure, or those particularly vulnerable to climate change. 88 Fed. Reg. at 33,413. Generally, these communities have a high prevalence of BIPOC populations, low-income individuals and families, and residents with limited English proficiency. These protocols should include specific guidance on how entities are to determine what languages a notice or proceeding must be translated into in a given situation.

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[126] SWG Report at 6.
[127] OMB, *Memorandum for the Heads of Executive Departments and Agencies: Broadening Public Participation and Community Engagement in the Regulatory Process,* 6–8 (July 19, 2023). https://www.whitehouse.gov/wp-content/uploads/2023/07/Broadening-Public-Participation-and-Community-Engagement-in-the-Regulatory-Process.pdf.
[128] SWG Report at 40.

The agency's threshold for requiring language translation and interpretation protocols should err on the side of inclusivity, which will impose minimal burden on the regulated community while granting access to key information to community members who would otherwise be shut out of the process. To determine which and how many languages notices and other information should be translated into, EPA should require states and agencies to accurately identify potentially impacted communities and determine the make-up of those communities. Any linguistic community of meaningful size in an impacted area should receive appropriately translated information.[129] EPA should also require the simultaneous release of project documents in English and other languages to ensure equal comment opportunities for limited English proficient residents.

In addition, EPA and its regional offices should conduct or review annual demographic studies to determine language access needs within each region. The agency and regional offices should maintain a current roster of local interpreters and translators with technical expertise in related matters such as energy, infrastructure, permitting, siting, and utility regulation that can be provided to states and industry as needed. Finally, the regional offices should work directly with community groups to identify the needs of persons with limited English proficiency and determine and implement measures to adequately address such needs.

iv. EPA should include requirements to ensure that hearings are effective and accessible to impacted community members.

Virtual meetings and hearings are a lingering impact of the COVID-19 pandemic. This has had great benefits for public process, as virtual hearings have enabled the participation of many people who would otherwise be unable to attend public meetings and hearings due to barriers such as work obligations, childcare and household needs, and transportation difficulties. To ensure that hearings remain accessible, EPA must require virtual access to all hearings. Virtual access has promoted greater and more equitable participation in proceedings before public bodies. Hybrid hearings allow interested parties to attend hearings in person if they are able while providing that members of the public who cannot attend in person can still participate. Additionally, EPA should ensure that in-person and hybrid hearings occur in accessible locations within impacted communities, and should also require multiple time options, including times during non-business hours to allow people who cannot leave work or who work multiple jobs to attend a hearing.

Physical accessibility is also vital to the public's ability to meaningfully engage in agency proceedings. To ensure this, EPA should require that in-person hearings are held at sites that meet

[129] EPA's guidance on addressing national origin discrimination affecting limited-English persons identifies four factors to consider when deciding whether to provide interpretation and translation services, including the nature and importance of the involved activity and the cost of these services relative to an entity's resources. EPA, *Guidance to Environmental Protection Agency Financial Assistance Recipients Regarding Title VI Prohibition Against National Origin Discrimination Affecting Limited English Proficient Persons*, 69 Fed. Reg. 35,602, 35,607 (June 25, 2004). Although the current rule proposal is not targeted at financial assistance recipients, the considerations found in this guidance apply with similar force. They suggest that EPA should err heavily on the side of requiring such services given the significant environmental and health issues at stake and the low cost of these services relative to the overall regulatory cost of the program.

requirements for ADA accessibility, are close to public transportation if available, have ample low-cost parking, are equipped for a hybrid component, and are set up to facilitate discussion and participation. Tools such as headphones should be available for people who are hard of hearing. An ASL interpreter should be available for any persons in the audience requiring sign language translation. ASL and language interpreters should be providing real-time, live interpretation of the hearings, as opposed to reading and translating from a record.

Interpretation should be carried out as soon as the event begins, and quality translation and interpretation services are essential. As noted above, EPA should maintain, and states should be required to maintain, a list of specific service agencies that offer effective language services. When interpreters lack the skills or technical knowledge needed to accurately communicate information—a not-infrequent occurrence—significant inequities in public participation result. Identifying language services providers who can adequately translate technical discussions is necessary to ensure the public's understanding of proposed activities and its ability to meaningfully engage around it. Interpreters should receive all presentation materials in advance. All materials distributed or displayed at these meetings, including agenda, notes, and slide presentations, must be provided in all languages simultaneously.

We recommend that EPA set, and require states and industry actors to meet, standards for inclusive participation in public hearings. This should include tracking participant demographics and comparing those data with the demographics of the affected community to ensure that turnout is representative and that barriers that certain populations may face are overcome. The agency could also ask participants to voluntarily self-identify as members of underrepresented groups and ensure such data is treated in a confidential manner. This data, in conjunction with consultation with community advocates, can help refine EPA's policies and guidance around meaningful engagement with affected communities.

Finally, EPA should require that states and industry maintain an accessible website that provides clear instructions for participation in hearings and in proceedings more generally. This site should also provide an accessible overview of the overall process and the role of public comments, including the weight they are given, evidentiary presumptions they must meet, and the degree to which decisionmakers must address them in formulating policy.

v. EPA should include uniform, user-friendly requirements related to EGU websites to ensure that they advance meaningful engagement effectively.

The Proposed Rule would obligate state plans to "require owners and operators of affected EGUs to establish publicly accessible websites." 88 Fed. Reg. at 33,400. On these sites, owners/operators would be required to post all reporting and recordkeeping information, as well as compliance schedules and data needed to demonstrate compliance with standards of performance. Information would need to be retained on the website for ten years, and owners/operators already subject to the Coal Combustion Residuals Rule ("CCR Rule") may use existing websites required by that Rule. *Id.* Joint Environmental Commenters support the requirement for publicly accessible websites as an important means of ensuring transparency and accountability. However, rather than call for a proliferation of numerous individual sites that may be difficult to locate and will be difficult to monitor for compliance, EPA should instead create its own central and standardized site for posting these records and reports. Should EPA choose not to do so, our experiences with CCR websites make clear that EPA must be much more prescriptive about the structure and content of these websites if they are to advance meaningful community engagement effectively.

CCR websites are intended to serve a similar function to the EGU sites here, and the CCR Rule is similarly non-specific in describing how information is to be presented on them. Absent specific standards, owners and operators have posted documentation on their CCR sites in ways that are inaccessible, inconsistent, and at times inscrutable.[130] Organizations such as Joint Environmental Commenters have had to expend significant amounts of limited time and resources to sift through poorly labelled and poorly organized files to identify critical information and to manually transfer non-machine-readable data into formats that allow for analysis. While this is a needless and cumbersome irritant for larger non-profit organizations, it is prohibitively burdensome for most environmental justice and grassroots community organizations (let alone individuals who may be interested in accessing these materials) and prevents the "meaningful and informed public participation" that is called for in E.O. 14,096 and prioritized in the Proposed Rule. Such organizations, which serve the communities most directly affected by specific coal ash sites, often lack the resources and technical capacity to track down and assess these reports. With uniform EPA standards and only minimal additional effort by industry, these websites and the reports they house could be designed to ensure adequate accessibility to lay users and community organizations of limited means.

One issue with CCR websites is that many categorize reports according to regulatory language from the CCR Rule. This includes website categories such as "Design Criteria," "Operating Criteria," "Groundwater Monitoring and Corrective Action," "Location Restriction Demonstration," and "Closure and Post Closure." While some of these titles hint at the information that can be found in underlying reports, others do not. For example, the average lay user is unlikely to know that information about the volume of waste stored at a facility can be found in an Annual Inspection Report, which can further be found in the "Operating Criteria" section of most sites. Moreover, some utilities do not group reports into substantive categories at all, instead listing all reports chronologically.[131] This poor organization requires users to rely on report titles alone to determine a file's contents, making it laborious and confusing for members of the public to track down specific information that is of interest to them. In addition, some CCR websites use indecipherable names for their reports. For example, Kentucky Utilities Company publishes groundwater monitoring reports under file names such as "W_BR_AXP_GMCA_GPSOVER_102918" [132] and Construction and Design reports under file names such as "W_BR_AXP_CDS_EAPCLS_012120."[133]

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[130] To maximize accessibility of this information, EPA would ideally require publication on one central and standardized website so that community members do not have to track down and navigate multiple company websites.
[131] For example, this is the case for Luminant's CCR website (https://www.luminant.com/ccr) and for NRG's CCR website (https://www.nrg.com/legal/coal-combustion-residuals.html).
[132] LG&E & KU, *Groundwater Monitoring and Corrective Action*, https://ccr.lge-ku.com/CCR/BR/AXP/GMCA (last visited July 13, 2023).
[133] LG&E & KU, *Construction/Design*, https://ccr.lge-ku.com/CCR/BR/AXP/CDS (last visited July 13, 2023).

If a user is able to find the report they are seeking, the pertinent information within it is often shrouded in confusing technical language. This is true, for example, for Annual Groundwater Monitoring and Corrective Action Reports, critical information required by the CCR Rule that indicates whether a facility is contaminating groundwater and, if so, what actions are being taken to address this. In addition, owners/operators present groundwater monitoring data in the form of tables within a PDF appendix rather than as a readily downloadable source of data, such as a comma-separated value (".csv") file. Scraping data from these PDF tables in order to evaluate it for compliance via data processing software is incredibly and needlessly time intensive. Although the CCR Rule requires information maintained on CCR websites to be "clearly identifiable," 40 C.F.R. § 257.107(a), owners/operators have used the discretion provided by this vague standard in ways that undermine EPA's intent. The agency can ensure that these same issues do not beset implementation of the final Carbon Pollution Standards with a few steps that make its expectations around accessibility explicit:

- EPA should prescribe user-friendly organizational requirements for websites and require owners/operators to provide a succinct and easily understood user guide on for their sites that describes the organizational system and the type of information that can be found in each area and report. EPA should write standardized language for such a guide and provide an organizational framework that owners and operators must adopt so that organization is consistent across sites and thus more user-friendly. Within this framework, reports and analyses that are associated with one another should be clearly referenced and labeled as such so that, among other things, users can readily identify analyses and plans that an owner/operator relied upon to support a given conclusion about compliance or planned future compliance. Prescribing a structure for information will not only enable the public to navigate the information provided on a website, it will also make it easier for users to identify any required information that is missing from the site.
- EPA should require owners/operators to summarize in lay terms information that is of greatest significance and concern to members of the public. This should include information on emissions, compliance requirements and schedules, compliance progress, and any ways in which the owner/operator is failing to meet its compliance obligations.
- EPA should require data to be provided in readily downloadable and machine-readable files, such as .csv files. EPA should also specify the type and format of information/fields to be contained in these .csv files to ensure that information reported across years and across utilities can be compared and that the data fields are understandable. Providing data in this manner will require negligible effort on the part of owners/operators.

As noted above, to further ensure that impacted and concerned members of the public have access to critical information, EPA should require owners/operators to provide notice when publishing key compliance activities and information to members of the public who indicate an interest in receiving it.

EPA proposes a 10-year retention period for documentation provided on EGU websites and seeks comment on whether this is sufficient. Given that such documentation is essential to meaningful community engagement and accountability, EPA should err heavily on the side of retention. Such documentation may be of interest to communities and potentially of legal relevance beyond 10 years. Maintenance of documentation over time is also critical to assessing the effectiveness of compliance activities at specific sites and the effectiveness of the Carbon Pollution Standards in general.

There is no compelling countervailing interest for relatively short retention requirements. Maintaining such documents online requires little to no effort. EPA should therefore require that owners/operators retain and report compliance documentation indefinitely and until such time that EPA affirmatively determines that the documentation is no longer of any relevance. In the event that EPA does allow documentation to be removed from an EGU website, the relevant owner/operator should be required to provide advance notice of its intent to do so, providing interested members of the public with the opportunity to save documents before they become inaccessible.

3. EPA should eliminate confusion caused by the interplay of existing and proposed rule language to ensure meaningful community engagement.

As discussed above, Joint Environmental Commenters strongly urge EPA to provide more specific direction to states and industry on what is required to ensure meaningful community engagement. EPA should also resolve inconsistencies and potential confusion caused by the interplay of proposed and existing rule language. In the preamble to the Proposed Rule, EPA asserts that "robust and meaningful public involvement in the development of a plan should sometimes go beyond the minimum requirement to hold a public hearing depending on who is most affected by and vulnerable to the impacts being addressed by the plan." 88 Fed. Reg. at 79,190.[134] EPA's proposed definition of meaningful engagement implies that it should include more, such as a variety of "public participation strategies" to overcome barriers to meaningful engagement.

Despite these assertions and EPA's expressed commitment to robust engagement, the 111(d) implementing regulations proposal retains existing rule language that simply requires states to hold "one or more public hearings" on a proposed 111(d) plan.[135] EPA also proposes to retain language indicating that notice requirements may be "satisfied by advertisement on the internet."[136] At the same time, according to the preamble to the Proposed Rule, "many states provide for notification of public engagement through the internet, however there cannot be a presumption that such notification is adequate in reaching all those who are impacted by a section 111(d) state plan and would benefit the most from participating in a public hearing." 88 Fed. Reg. at 79,191. The implementing

[134] Joint Environmental Commenters believe that robust and meaningful public engagement *always* requires more than a single public hearing.
[135] Michelle Bergin, EPA, *Memorandum re: Redline/Strikeout for proposed amendments to 40 CFR 60 Subpart Ba: Adoption and Submittal of State Plans for Designated Facilities*, 6 (Dec. 6, 2022), https://www.epa.gov/system/files/documents/2023-01/Regulatory%20Text%20proposed%20changes%20to%2040%20CFR%20part%2060%20subpart%20Ba_0.pdf
[136] *Id.*

regulations proposal also retains language that specifically allows states to cancel the one required public hearing "if no request for a public hearing is received during the 30 day notification period."[137]

The inconsistency between EPA's broadly stated goals for meaningful engagement and the specifically described requirements for state plans must be resolved. It would be understandable for well-intended actors to be confused by it. Worse still, experience makes extremely clear that a number of state and industry actors will do the bare minimum that they can plausibly (or at times implausibly) assert is required under the law, which in this instance would be the actions specifically required under the rule. To afford meaningful engagement, EPA must eliminate the clearly insufficient requirements set forth in the rule and more specifically indicate the activities required, including those recommended above, in the regulatory text itself.

B. EPA Must Take Steps to Minimize the Rule's Uneven Distribution of Conventional Pollution Impacts.

In both the preamble and in its public messaging around the Proposed Rule, EPA has placed great emphasis on the rule's anticipated public health benefits. For example, in the *Fact Sheet for Communities with Environmental Justice Concerns* published on its public website, EPA tallies its projections that "[i]n 2030 alone, the health benefits of the proposals on new gas and existing coal include approximately 1,300 avoided premature deaths; more than 800 avoided hospital and emergency room visits; approximately 2,000 avoided cases of asthma onset; more than 300,000 avoided cases of asthma symptoms; 38,000 avoided school absence days; and 66,000 lost work days."[138] These certainly are impressive statistics, and Joint Environmental Commenters eagerly welcome improvements in public health of this magnitude.

However, a closer look at EPA's Regulatory Impact Analysis (RIA) leaves us with significant concerns about the way in which these health benefits—and corresponding health disbenefits—will be distributed, at least according to EPA's modeling. Section 6.5 of the RIA, and Figures 6-1 through 6-10 in particular, indicate that while the program is projected to deliver large aggregate reductions in ozone and $PM_{2.5}$ in nearly every scenario-year analyzed, those benefits will be quite unevenly distributed.[139] Figure 6-1 shows hundreds of millions of people living in areas with increased ozone and tens of millions living in areas with increased $PM_{2.5}$ as a result of the rule.[140] A disparity of this nature cuts against a key goal of public health, which is to improve outcomes for *all* populations.

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[137] *Id.*

[138] EPA, *Fact Sheet for Communities with Environmental Justice Concerns: Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants Proposed Rule*, 2 (May 2023), https://www.epa.gov/system/files/documents/2023-05/FS-EJ-GHG-for%20Power%20Plants%20-%20FINAL%205-10-23.pdf.

[139] EPA, *Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, Dkt. No. EPA-HQ-OAR-2023-0072-0007, Sections 6.5 and 6.6 (May 2023), https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0007/content.pdf.

[140] *Id.*

These distributional disparities in conventional pollution are likely to result from operators' efforts to shift load away from more heavily-regulated units (like new baseload combustion turbines) and toward less-heavily regulated units (like existing combustion turbines that are not covered under the emission guidelines). We also recognize that the modeling described in Sections 6.5 of the RIA did not include key portions of EPA's proposal—namely, the emission guidelines for existing sources and the third regulatory phase for new baseload turbines—and that the actual disparities resulting from the proposal may therefore be lower than what was projected in the modeling.[141]

It is of the utmost importance that the final rule reduce distributional inequalities in conventional pollution impacts to the greatest extent possible. This requires EPA to minimize operators' incentives to shift load to less-efficient, less stringently regulated sources. For example, the agency must tighten the stringency of its requirements for both existing gas turbines and new units not subject to CCS or hydrogen requirements, such as simple cycle turbines. In crafting its final rule, the agency must pay close attention to distributional impacts and must deprioritize certain other values—such as operator convenience and industry profit margins—to provide as equitable an array of benefits as possible. This may require the agency not to permit certain industry practices (such as running simple cycle turbines as seasonal baseload units) that operators have recently pursued and would like to continue to pursue. Of course, the agency should do that in any event for climate reasons, but it can and must consider the distribution of conventional pollution as well.

In issuing its final rule, EPA must not exacerbate—and, indeed, make every effort to mitigate—existing disparities in pollution that have, for many decades, jeopardized the health and well-being of EJ communities. While the agency concludes that the rule is generally unlikely to either mitigate or exacerbate existing disparities of ozone and $PM_{2.5}$ exposure between EJ and non-EJ groups, it nonetheless shows potentially increased levels of ozone concentrations for Hispanic, Asian, and linguistically isolated groups in 2030 and ozone decrease for all other groups. Moreover, air pollution modeling is only so precise, and it is possible that the rule as proposed could cause other racial/ethnic or income-based disparities that the modeling cannot capture. EPA must be particularly focused on environmental justice outcomes and take great care to minimize the disparities that already exist.

Finally, the agency must forge ahead with other Clean Air Act regulations and use those opportunities to provide maximal protection against conventional pollution from power plants. For instance, earlier this year, EPA proposed to lower the annual NAAQS for $PM_{2.5}$ from 12 $\mu g/m^3$ to a range of 9–10 $\mu g/m^3$, 88 Fed. Reg. 5,558 (Jan. 27, 2023), even while many environmental[142] and public health groups[143] (including several of the Joint Environmental Commenters) have argued that a standard no

[141] Due to the very high combustion temperature of hydrogen, the more widespread use of hydrogen co-firing, as opposed to certain other compliance strategies, could also increase NO_x emissions in certain areas.
[142] *See, e.g.*, Earthjustice, Sierra Club, *et al.*, *Comments on the Reconsideration of the National Ambient Air Quality Standards for Particulate Matter*, Dkt. No. EPA-HQ-OAR-2015-0072-2233, 23–90 (March 28, 2023), https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0007/content.pdf, included as Exhibit 41.
[143] Paul Billings, Nat'l Senior Vice President of Public Policy, American Lung Assoc., testimony delivered at hearing on EPA's Reconsideration of the National Ambient Air Quality Standards for

higher than 8 $\mu g/m^3$ to was sufficient to adequately protect public health. These groups have also urged EPA to lower the 24-hour $PM_{2.5}$ standard from 35 $\mu g/m^3$ to 25 $\mu g/m$.[144] In addition, for years, environmental and public health advocates have urged the agency to adopt a far lower NAAQS for ozone,[145] and in June of this year, EPA's Clean Air Scientific Advisory Committee for ozone recommended a limit of 55–60 ppb in a comprehensive study of the existing research.[146] The agency must move swiftly forward with tougher NAAQS for $PM_{2.5}$ and ozone, as well as other regulations limiting conventional pollution from the power sector.

C. EPA Must Provide, and Require States to Provide, A Cumulative Impacts Analysis and Ensure that Such Impacts Are Addressed.

Environmental justice advocates have long highlighted the need for policymakers to address environmental problems not as atomized events, but as series of interlocking crises in which the cumulative impact of the whole exceeds the sum of its parts. To give a prime example, communities along the Texas Gulf Coast—a region that is majority Black and Hispanic[147]—are experiencing high levels of air pollution from multiple pollutants,[148] water quality degradation from petroleum refineries[149] and other industrial facilities, safety and land-use concerns due to a growth in LNG

Particulate Matter (Feb. 21, 2023), https://www.lung.org/getmedia/5c1e3daa-3e38-454b-93af-288824bf3a00/Paul-Billings-Testimony-to-EPA-on-PM-NAAQS-Proposal-2-2023.pdf, included as Exhibit 42.

[144] Earthjustice, *supra* n. 142, at 91–107.

[145] Sierra Club, Earthjustice, et al., Comments on EPA's Proposed Revisions to the National Ambient Air Quality Standards for Ozone, Dkt. No. EPA-HQ-OAR-2008-0699-2720, 20–127 (March 17, 2015), https://downloads.regulations.gov/EPA-HQ-OAR-2008-0699-2720/attachment_3.pdf, included as Exhibit 43.

[146] Clean Air Sci. Advisory Comm. (CASAC) Ozone Review Panel, *CASAC Review of the EPA's Policy Assessment (PA) for the Reconsideration of the Ozone National Ambient Air Quality Standards (External Review Draft Version*, D-36 (June 9, 2023), https://casac.epa.gov/ords/sab/f?p=113:0:15759510615691:APPLICATION_PROCESS=REPORT_DOC:::REPORT_ID:1114

[147] Comptroller of Texas, *The Gulf Coast Region: 2020 Regional Report*, https://comptroller.texas.gov/economy/economic-data/regions/2020/gulf-coast.php (last visited Aug. 6, 2023).

[148] Press Release, Rebeca Hawley, Univ. of Houston, Study Finds Sulfate Pollution Impacts Texas Gulf Coast Air (March 29, 2023), https://uh.edu/news-events/stories/2023/march-2023/study-finds-sulfate-pollution-impacts-texas-gulf-coast-air.php; Rebekah F. Ward and Alexandra Kanik, *Houston's early season of ozone pollution poses health to residents, forcing some to say [sic] inside*, HOUSTON CHRONICLE, June 23, 2023, https://www.houstonchronicle.com/news/houston-texas/environment/article/houston-ozone-pollution-health-risks-early-18149575.php.;

[149] Envtl. Integrity Project, *Oil's Unchecked Outfalls: Water Pollution from Refineries and EPA's Failure to Enforce the Clean Water Act*, Table 1 and 42–44 (Jan 6, 2023), https://environmentalintegrity.org/wp-content/uploads/2023/01/Oils-Unchecked-Outfalls-03.06.2023.pdf (showing significant numbers of highly polluting refineries in the Texas Gulf Coast region and discussing the particular burdens faced by Port Arthur).

infrastructure,[150] and climate-related weather and temperature phenomena such as extreme heat,[151] rising water levels,[152] and more powerful hurricanes.[153] Any single one of these categories of environmental harm would impose a very large burden on the affected communities. Cumulatively, they are devastating.

EPA must address the ways in which the final rule will alleviate and/or exacerbate cumulative impacts suffered by EJ communities. Even while the Proposed Rule is national in scope and EJ communities are highly localized, EPA can analyze, for example, the geographic areas that it projects to experience the greatest impacts from the rule (such as the states with the greatest increases or decreases in conventional pollution) and then address those outcomes in conjunction with other environmental impacts that occur in that area. The Texas Gulf Coast is a good example of a region that encompasses many distinct EJ communities, but which is characterized by certain problems that are broad and consistent enough to allow for a more macro-level cumulative impacts analysis.

Cumulative impacts assessments will be critical in the state plan development process. As discussed above, robust and involved stakeholder outreach conducted by states will help incorporate affected communities into the decisionmaking process. In addition, states should be required to evaluate not just how their proposed plans will affect impacted communities, but must craft those assessments to address cumulative impacts. Fortunately, several tools are currently available to facilitate these kinds of analyses. The most notable of these is EPA's "Environmental Justice Screening and Mapping Tool," or EJScreen.[154] This program provides an interactive map that allows users to access data for a dozen "environmental justice indexes." These include as ozone and $PM_{2.5}$ concentrations, toxic releases to the air, hazardous waste proximity, and waste water discharges. The tool also provides data on pollution sources, socioeconomics, health disparities, climate change, critical service gaps, and comprehensive demographics, permitting users to compare each tract's data with national and state percentiles.

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[150] Liz Hampton, Sabrina Valle and Scott Disavino, *Freeport LNG plant blast adds to strain on global supplies*, REUTERS, June 9, 2022, https://www.reuters.com/business/energy/explosion-hits-freeport-lng-plant-us-natgas-prices-plunge-2022-06-08/ (discussing 2022 explosion at liquified natural gas facility in Freeport, Texas).

[151] David Yeomans, KXAN Weather Blog, *Record warm Gulf of Mexico partially responsible for Texas heat wave* (July 14, 2023), https://www.kxan.com/weather/weather-blog/record-warm-gulf-of-mexico-partially-responsible-for-texas-heat-wave/.

[152] Sönke Dangendorf, et al., *Acceleration of U.S. Southeast and Gulf coast sea-level rise amplified by internal climate variability*, 14:1935 NATURE COMMUNICATIONS (2023), https://www.nature.com/articles/s41467-023-37649-9; Sana Ameer, *Texas coast at risk as Gulf of Mexico sea levels rise*, BEAUMONT ENTERPRISE, April 18, 2023, https://www.beaumontenterprise.com/news/article/new-report-gulf-of-mexico-sea-levels-rising-17896562.php

[153] Michael E. Mann, *It's a fact: climate change made Hurricane Harvey more deadly*, THE GUARDIAN, Aug. 28, 2017, https://www.theguardian.com/commentisfree/2017/aug/28/climate-change-hurricane-harvey-more-deadly.

[154] EPA, *EJScreen: EPA's Environmental Justice Screening and Mapping Tool (Version 2.11)*, https://ejscreen.epa.gov/mapper/ (last visited May 17, 2023).

Additionally, The White House Council on Environmental Quality has created a "Climate and Economic Justice Screening Tool."[155] This program locates census tract-based overburdened communities based on multiple factors, including climate change, energy, health, housing, legacy pollution, transportation, water and wastewater, and workforce development. And states such as California[156] and New Jersey[157] have developed their own tools for locating and evaluating communities suffering from cumulative environmental impacts, indicating that federal policymakers are not alone in pursuing this kind of analysis.

Simply put, a cumulative impacts analysis is necessary to see the full picture of any regulation designed to reduce pollution. It is particularly important for this rule given the outsized burden that power plant emissions impose on environmental justice communities, as well as the possibility that the final rule, if not properly designed, could exacerbate existing pollution disparities—and thus heighten the cumulative impacts—that harm some such communities. EPA must therefore include a cumulative impacts analysis of its own in the final rule and direct states to conduct similar, more granular studies as part of their plan development process. This analysis must not merely be an afterthought, but must guide EPA's and states' decisionmaking processes and inform the substance of both the final rule and itself the state plans implementing it.

D. EPA Must Ensure Full Consideration of, and Meaningful Engagement with, Energy Sector Workers and Communities.

We cannot avoid the worst impacts of climate change without rapidly reducing—and, indeed, eliminating—U.S. CO_2 emissions from the electric sector. No less important, however, is lifting up energy sector workers and communities as we transition to a clean economy. As U.S. coal mining jobs continue to decrease and coal-fired power plants continue to shutter, we must not leave workers or communities behind. EPA must consider the workers and communities experiencing the economic impacts of energy transition as it helps to ensure a clean, prosperous, and equitable economy for all.

As it continues on with its rulemaking, EPA must engage with energy workers and communities likely to be impacted by the closure of power plants projected to occur as a result of his rule, and require states to meaningfully engage with those communities, workers, and their worker representatives. EPA should further encourage states to prioritize impacted communities and workers in their state plans, while at the same time ensuring the greatest possible emission reductions under the final rule.

Power plant closure dates are a key aspect of compliance with the proposed rule. As currently written, the rule requires state plans to include federally enforceable retirement dates for existing coal units in

[155] Council on Envtl. Quality, *Climate and Economic Justice Screening Tool*, https://screeningtool.geoplatform.gov/ (last visited May 17, 2023).
[156] California Office of Envtl. Health Hazard Assessment, *CalEnviroScreen 4.0* https://experience.arcgis.com/experience/11d2f52282a54ceebcac7428e6184203/page/CalEnviroScreen-4_0/ (last visited May 30, 2023).
[157] New Jersey Dep't of Envtl. Prot., *Environmental Justice Mapping*, Assessment and Protection Tool (EJMAP), https://experience.arcgis.com/experience/548632a2351b41b8a0443cfc3a9f4ef6 (last visited May 30, 2023).

the imminent-, near-, and medium-term subcategories. At least five years before each source's retirement date or 60 days after a state plan is submitted for approval to EPA, each source owner must announce its federally enforceable retirement date to the appropriate state and load-balancing authorities, along with a description of the process steps leading up to retirement. Proposed 40 C.F.R. § § 60.5740b(a)(5)(i)(A)–(B). This is a vital provision that must be retained in the final rule and strictly enforced by EPA. Clear and enforceable retirement dates are not only critical for generation planning purposes, but also for allowing communities and workers plan for impending closures. EPA should also work with utilities to gather workforce data to assist workers, communities, and local governments with economic planning.

EPA should work also closely with the Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization to target federal resources to communities with impending coal plant and coal mine closures, and should direct portions of its own resources to assisting these communities.

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