COMMENTS OF THE
UTILITY AIR REGULATORY GROUP

on the

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY'S

EMISSION GUIDELINES FOR GREENHOUSE GAS EMISSIONS FROM EXISTING ELECTRIC UTILITY GENERATING UNITS; REVISIONS TO EMISSION GUIDELINE IMPLEMENTING REGULATIONS; REVISIONS TO NEW SOURCE REVIEW PROGRAM; PROPOSED RULE

83 FED. REG. 44,746 (Aug. 31, 2018)
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Allison D. Wood
Makram B. Jaber
Lauren E. Freeman
Lucinda Minton Langworthy
Andrew D. Knudsen
HUNTON ANDREWS KURTH LLP
2200 Pennsylvania Avenue, NW
Washington, D.C. 20037
(202) 955-1500

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Counsel for the Utility Air Regulatory Group

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Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program; Proposed Rule

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The Utility Air Regulatory Group ("UARG") submits the following comments in response to the U.S. Environmental Protection Agency's ("EPA" or "Agency") proposed rule entitled "Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program," which is commonly referred to as the Affordable Clean Energy or ACE Rule and which was published in the Federal Register on August 31, 2018. 83 Fed. Reg. 44,746 (Aug. 31, 2018) ("Proposed ACE Rule" or "Proposal").

UARG is a not-for-profit association of individual electric generating companies and national trade associations. UARG participates on behalf of certain of its members collectively in Clean Air Act ("CAA" or "Act") administrative proceedings that affect electric generators and in litigation arising from those proceedings.[1] The electric generating companies that are members of UARG construct, own, and operate power plants, including fossil fuel-fired power plants, and other facilities that generate electricity for residential, commercial, industrial, institutional, and government customers. Operation of these fossil fuel-fired power plants results in emissions of carbon dioxide ("CO_2"). As such, many of these plants would be "affected electric generating units" as defined in

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[1] Dominion Energy does not participate in these comments.

the Proposed ACE Rule and thus subject to the rule. UARG therefore has a clear and significant interest in the Proposed ACE Rule and in any future EPA efforts to regulate CO_2 and other greenhouse gas ("GHG") emissions under the CAA.

In UARG's comments on EPA's Advance Notice of Proposed Rulemaking ("ANPR"), UARG encouraged EPA to propose and finalize a replacement to the Clean Power Plan ("CPP") (as opposed to merely repealing that rule). EPA-HQ-OAR-2017-0545-0275 ("UARG ANPR Comments"). As detailed further in these comments, UARG supports the Proposed ACE Rule and suggests how the rule could be improved.

Comments on the Portion of the Proposed ACE Rule Regarding the Proposed Emission Guidelines To Address GHG Emissions from Existing Electric Utility Generating Units Under Section 111(d) (Proposed Subpart UUUUa)

I. EPA's Legal Authority for the Proposed ACE Rule

EPA's emission guidelines to address GHG emissions from existing electric generating units ("EGUs") are consistent with section 111(d) of the CAA. It is well established that EPA's regulatory reach under section 111 is narrow and limited, and the Proposed ACE Rule properly respects the scope and bounds of the Act. Specifically, the Proposed ACE Rule identifies the best system of emission reduction ("BSER") for coal-fired utility boilers based on measures that can be applied at or to an individual source, and it acknowledges states' primary responsibility to submit their own plans establishing achievable standards of performance for each source considering unit-specific factors.

A. It Is Appropriate for EPA To Adopt Replacement Emission Guidelines for Existing EGUs While Its Review of the Current New Source Performance Standards ("NSPS") Is Pending.

Regulation of new sources in a source category under section 111(b) of the CAA is a prerequisite to regulation of existing sources under section 111(d). Section 111 of the CAA directs EPA to list categories of stationary sources that it determines contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. CAA § 111(b)(1)(A). After a source category has been listed by EPA, the Agency is required to establish NSPS for new and modified sources for the category pursuant to CAA section 111(b). *Id.* § 111(b)(1)(B). Once EPA has issued an NSPS pursuant to 111(b), in certain limited situations, EPA must issue emission guidelines under section 111(d) that will guide states in setting standards of performance for existing sources in the category.

EPA issued standards of performance for GHG emissions from new, modified, and reconstructed EGUs under section 111(b) in 2015.[2] 80 Fed. Reg. 64,510 (Oct. 23, 2015) ("2015 NSPS"). These regulations cover both utility boilers and combustion turbines. *Id.* Numerous parties, including UARG, filed petitions for review in the D.C. Circuit challenging the NSPS for utility boilers as being unlawful, while no one challenged the NSPS for combustion turbines. *See North Dakota v. EPA*, No. 15-1381 (and consolidated cases) (D.C. Cir. filed Oct. 23, 2015). This litigation has been stayed pending EPA's administrative review of the 2015 NSPS, which was directed by the President on March 28, 2017. Exec. Order No. 13783, 82 Fed. Reg. 16,093 (Mar. 31, 2017). EPA has sent a proposed rule resulting from its review of the 2015 NSPS to the Office of Management and Budget ("OMB") for interagency review. *See* Office of Info. & Regulatory Affairs, Pending EO 12866 Regulatory Review, "Review of Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units," https://www.reginfo.gov/public/do/eoDetails?rrid=128462. The 2015 NSPS requirements remain in effect pending completion of that rulemaking and have not been stayed.

UARG supports EPA's decision to proceed with promulgating replacement emission guidelines for existing EGUs while it undertakes review of the 2015 NSPS. Given that EPA cannot regulate existing EGUs without an NSPS for new EGUs, UARG encourages EPA to revise or replace the NSPS for utility boilers rather than repeal them. *See* CAA § 111(d)(1).

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[2] EPA first made an endangerment finding for GHG emissions in 2009 and found that motor vehicles contributed to that endangerment. 74 Fed. Reg. 66,496 (Dec. 15, 2009). UARG does not support overturning or reversing that finding. Any questions regarding EPA's endangerment finding for GHG emissions from EGUs should be addressed in connection with EPA's review of the section 111(b) NSPS, and in that review EPA should also address the specific requirement of section 111 that sources contribute "significantly" to endangerment before regulation under that CAA section may occur.

B. The Proposed ACE Rule Properly Reserves States' Autonomy as Outlined in Section 111(d).

The Proposal properly addresses the relationship between federal and state governments in regulating existing sources under section 111(d). Unlike section 111(b), where EPA has primary regulatory responsibility, section 111(d) of the CAA establishes a clear division of roles and responsibilities between EPA and the states in regulating existing sources. Rather than establishing a single federal standard, the Proposed ACE Rule respects EPA's traditional function of promulgating guidelines that govern the states' crafting of their own individual plans, consistent with section 111(d). 83 Fed. Reg. at 44,762-63.

Under section 111, standards of performance must reflect the "degree of emission limitation achievable through the application of the best system of emission reduction which … the Administrator determines has been adequately demonstrated." CAA § 111(a)(1). In order to determine the BSER, EPA must analyze potential adequately demonstrated systems of emission reduction for sources within the category and then identify the "best" one, accounting for cost and "any nonair quality health and environmental impact and energy requirements." *Id.*

For a system of emission reduction to be adequately demonstrated, the system must allow for reliable and efficient operation, and "serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way." *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973). The D.C. Circuit has held that for a standard to be achievable it must be capable of being met "for the industry as a whole," "under the range of relevant conditions which may affect the emissions to be regulated," including "under most adverse conditions which can reasonably be expected to recur." *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431 & n.46, 433 (D.C. Cir. 1980). In contrast to regulation under other provisions of the Act, section 111 standards are not based on achieving specific health or welfare-based emission reduction goals. Rather, section 111 standards are technology-based in that they are limited to what individual sources can achieve through application of emission control systems.

Although the definition of the standard of performance is the same for section 111(b) and section 111(d), the process by which standards of performance are promulgated for existing sources is entirely different. Section 111(d) requires that states, not EPA, establish standards of performance for individual existing sources based on consideration of source-specific factors, like the cost, feasibility, and remaining useful life of the existing source. CAA § 111(d)(1). EPA lacks authority to override these statutory considerations by mandating that standards in state plans achieve a minimum level of stringency. *See Am. Elec. Power Co. v. Connecticut*, 564 U.S. 410, 428 (2011) (noting section 111(d) allows "each State to take the first cut at determining how best to achieve EPA emissions standards within its domain").

Once states submit their plans, EPA's role is limited to reviewing a state plan to determine whether to approve it. *See* CAA § 111(d)(2)(A). If the state fails to submit a plan or if a submitted plan is unsatisfactory, EPA must promulgate a federal plan. *Id.* § 111(d)(1), (2).

C. Determining BSER at Individual Sources

The Proposed ACE Rule reflects EPA's historical interpretation of § 111(d) that the BSER for a source category must be a system that can be applied at or to an individual source. 83 Fed. Reg. at 44,752. Section 111 focuses exclusively on individual sources. For instance, NSPS apply only to "new sources within [a listed] category," while state standards under section 111(d) apply to "any existing source … to which [an NSPS] … would apply if such existing *source* were a new *source*." CAA § 111(b)(1)(B), (d)(1) (emphases added). Furthermore, the section 111(d) provision directing states to consider the remaining useful life and other factors reflects characteristics that apply only to a specific, individual source. *Id.* § 111(d)(1). The language of section 111(d) makes it clear that standards must be based on the level of control that individual sources within listed categories can achieve.

In this Proposed ACE Rule, the Agency provides additional legal support for concluding that the scope of the BSER is limited to measures that can be applied to or at an individual source. 83 Fed. Reg. at 44,752. As EPA recognizes, reduced utilization of a source is not a system of emission reduction and thus cannot be used to set a standard of performance. *Id.* A system of emission reduction limits how much a source emits during operation—it does not authorize limits on performance at a source. "Performance" is "[t]he accomplishments, execution, carrying out, … [or] doing of any action or work." 11 OXFORD ENGLISH DICTIONARY 544 (J.A. Simpson & E.S.C. Weiner eds., 2d ed. 1989). A "standard of performance" is thus a principle to judge the execution of work by the source, not an order to stop working. Reduced utilization does not involve a source improving the emission rate at which it performs work, but instead consists of plants *reducing* or *ceasing* work, or *non*-performance. As the Supreme Court held in *Solid Waste Agency of Northern Cook County v. U.S. Army Corps of Engineers*, 531 U.S. 159 (2001), courts must give statutory terms meaning, even where they are part of a larger statutorily defined phrase*, id.* at 172 (requiring that the word "navigable" in the Clean Water Act's statutorily defined term "navigable waters" be given "effect").

Further, a section 111 "standard of performance" is defined as a "standard for emissions," which reflects the "degree of emission limitation" that a source may "achiev[e]" using the BSER. CAA § 111(a)(1). The phrase "emission limitation" is defined as a "requirement … which limits the quantity, rate, or concentration of emissions of air pollutants *on a continuous basis*." *Id.* § 302(k) (emphasis added). Congress's intent is clear: the term "continuous" was added to this definition in 1977 to signify that technological or low-polluting processes to achieve pollutant reductions during production are "to be the basis of the standard," H.R. Rep. No. 95-294, at 11 (1977), *reprinted in* 1977 U.S.C.C.A.N. 1077, 1088, rather than the use of "intermittent controls" such as temporarily reducing operations or shifting production to other sources, *id.* at 92, *reprinted in* 1977 U.S.C.C.A.N. 1170; *see id.* at 81, 86-87, *reprinted in* 1977 U.S.C.C.A.N. 1159-60, 1164-65. In other words, Congress required that performance standards be based on sources implementing control technology or low-polluting processes and not on sources ceasing or reducing operations.

Second, EPA is also correct that the prevention of significant deterioration ("PSD") program's prohibition on using the standard-setting process to "redefine the source" being regulated extends to standard-setting under section 111. 83 Fed. Reg. at 44,752-53. The PSD program is fundamentally intertwined with NSPS under section 111(b): Congress explicitly tied the two programs together by, *inter alia*, requiring that any applicable standard of performance under section 111 must provide a regulatory floor for "best achievable control technology" ("BACT") standards imposed under the PSD program. CAA § 169(3). But if the standard of performance is based on a "system of emission reduction" that would fundamentally redefine the source, it cannot meaningfully inform a BACT standard for that source, disrupting Congress's regulatory framework.

EPA has long recognized that the CAA's PSD provisions do not allow the use of BACT emission standards to redefine a source or interfere with the source owner's objective or purpose for the facility. *See, e.g.*, *In re Prairie State Generating Co.*, 13 E.A.D. 1, 23 (EAB 2006), *aff'd sub nom. Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007) (stating "the permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility"); *In re City of Palmdale (Palmdale Hybrid Power Project)*, 15 E.A.D. 700, 729 (EAB 2012) (stating permit issuer is "not required to consider inherently lower polluting technology alternatives that would require 'redefining the design' of the source as proposed by the permit applicant"); EPA, New Source Review Workshop Manual at B.13 (Draft Oct. 1990), https://www.epa.gov/nsr/nsr-workshop-manual-draft-october-1990 ("Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives."). The Agency's longstanding interpretation reflects "'a central concern with preservation of the facility's basic purpose.'" *Prairie State*, 13 E.A.D. at 21 (citation omitted). In 2011, EPA confirmed that in the context of greenhouse gases, the CAA still constrains the PSD permitting agency from interfering in a source's business purpose via standard-setting. *See* EPA, PSD and Title V Permitting Guidance for Greenhouse Gases at 26 (Mar. 2011), https://www.epa.gov/sites/production/files/2015-07/documents/ghgguid.pdf ("GHG Permitting Guidance") ("BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.").

EPA's interpretation has been endorsed by the courts. In *Sierra Club*, the Seventh Circuit recognized that EPA's approach regarding what constitutes "redefin[ing] the source" reflects a reasonable application of the CAA's distinction between emission controls (which may be considered in establishing BACT standards) and alternative source configurations (which may not). 499 F.3d at 654-57. Further, in *Utility Air Regulatory Group v. EPA*, the Supreme Court recognized that "it has long been held that BACT cannot be used to order a fundamental redesign of the facility." 134 S. Ct. 2427, 2448 (2014).

Given the connections between the CAA's NSPS and PSD programs, it is reasonable to apply the same prohibition on redefining the source in both NSPS and BACT standard-setting. Likewise, the same interpretive constraints on BSER with respect to section 111(b) extend to existing sources regulated under section 111(d). In fact, the policies underlying this doctrine apply with even greater force to existing sources, where changing the fundamental design or purpose would require significant changes to the source after it has already been built. If the CAA forbids EPA or a permitting agency from interfering in the basic purpose and design of a proposed source before it has been constructed, it certainly forbids EPA from doing so at an existing source, where investments have already been made in a particular design.

II. Selection of BSER for EGU Subcategories

A. Heat Rate Improvement Measures Applied at the Source are the Appropriate BSER for Coal-Fired Steam Generating Units. (Comment C-2)

1. EPA Correctly Identified the BSER. (Comments C-2, C-9)

EPA has proposed to designate the implementation of "heat rate improvements" (referred to elsewhere in the Proposal as "efficiency improvements") at the individual designated facility as the BSER for existing coal-fired utility boilers. 83 Fed. Reg. at 44,756. UARG agrees. Heat rate improvements can effectively reduce a unit's CO_2 emission rate by reducing the amount of heat needed to produce a given unit of electricity, thereby reducing the amount of fuel combusted (and CO_2 emitted) as a function of output. Application of heat rate improvement measures is an adequately demonstrated method of reducing a coal-fired utility boiler's CO_2 emission rate,[3] and emission standards based on improving or maintaining a unit's efficiency will provide meaningful limits on designated facilities' emissions.

As discussed above, an adequately demonstrated system of emission reduction is "one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way." *Essex Chem. Corp.*, 486 F.2d at 433; *see also Nat. Res. Def. Council v. Thomas*, 805 F.2d 410, 428 n.30 (D.C. Cir. 1986). In other words, it must be dependable, effective, and affordable for individual sources, based on actual operating experience within the source category. Those criteria are met here. Although there are specific heat rate improvement technologies and practices (discussed below) that would not qualify as "adequately demonstrated" due to lack of commercial availability, unreasonable costs, or other factors, the class of heat rate

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[3] Unless otherwise noted, references to CO_2 "emission rates" in these comments generally refer to mass of CO_2 emitted per unit of electricity generated, such as pounds per megawatt-hour ("lb/MWh").

improvement measures that EPA identifies as BSER are currently in wide use to improve and maintain the efficiency of coal-fired utility boilers. Many heat rate improvement measures are available at reasonable cost—in fact, because increased efficiency allows steam generating units to produce the same amount of electricity by combusting less fuel, some of these measures can yield reduced fuel costs, although savings are generally not sufficient to offset the cost of implementing them. While the potential improvement in heat rate at each individual unit varies significantly, all coal-fired units can implement measures that maintain efficiency and minimize the effects of equipment degradation on the unit's heat rate over time.

Owners of coal-fired utility boilers have extensive experience implementing heat rate improvements because of economic incentives (and in some cases, legal obligations) to operate as efficiently as possible. As EPA has previously recognized, the largest operating cost by far of generating electricity is the cost of fuel. EPA, EPA-452/R-15-005, Regulatory Impact Analysis for the Final Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units at 4-20 to 4-21 (Aug. 2015), EPA-HQ-OAR-2013-0495-11877 ("RIA for New, Modified, and Reconstructed EGUs"). Heat rate represents the amount of heat (and correspondingly, the amount of fuel combusted) that is required to generate a given unit of electricity. Many owners of coal-fired units operate their generating resources based on security constrained economic dispatch, in which (subject to reliability and security constraints) the least cost units are dispatched first to keep costs as low as possible. Because keeping costs low involves minimizing fuel costs, it is standard operating practice for coal-fired utility boiler owners and operators to undertake heat rate improvement measures on an ongoing basis to maintain and improve their efficiency. *See* UARG ANPR Comments at 25-26.

Because of this, many of the heat rate improvement measures EPA has identified have already been undertaken at these units. As the Public Utility Commission of Texas ("PUCT") noted in its comments on the proposed CPP, Texas' competitive wholesale electricity market "has forced coal-fired generators to adopt state of the art technologies available to improve thermal efficiencies in order to compete effectively, and there are few additional gains available." PUCT CPP Comments at 42 (Dec. 1, 2014), EPA-HQ-OAR-2013-0602-23305. In its comments on the proposed CPP, the National Rural Electric Cooperative Association ("NRECA") stated that "[b]ecause cost savings are passed directly to members, cooperatives work constantly to ensure that their generating assets are well maintained and operated in a way that maximizes electric output for any given quantity of fuel input." NRECA CPP Comments at 52 (Dec. 1, 2014), EPA-HQ-OAR-2013-0602-33118.

Further, in some cases independent system operators and state public utility commissions even *require* owners and operators of units within their jurisdiction to implement measures to maintain efficiency. These entities have an interest in ensuring that consumers are paying the lowest rates that they can for electricity and may require units to demonstrate that they are taking steps to ensure that they generate electricity as efficiently and cost-effectively as possible. For example, in Michigan, utility actions regarding the efficiency of fossil fuel-fired EGUs are subject to ongoing review and analysis in general rate cases before the Michigan Public Service Commission. *See* Order, Mich. Pub. Serv. Comm'n, Case No. U-15316 & U-15631 (Sept. 15, 2009), https://w2.lara.state.mi.us/ADMS/Mpsc/ViewCommissionOrderDocument/7917 (ordering regulated electric utilities with fossil fuel generation to file 10-year fossil fuel generation efficiency plans every three years).

Unsurprisingly, then, many owners of coal-fired utility boilers incorporate heat rate considerations into their fleetwide operating and maintenance practices. American Electric Power ("AEP") has previously noted to EPA that it is "standard practice in the utility industry to utilize preventative maintenance and routine cleaning practices that promote and sustain efficient operations," and that AEP itself "participate[s] in industry workshops, users group meetings and other forums to share best operating and maintenance practices to improve overall plant performance," including "improving heat rate." AEP CPP Comments at 64 (Dec. 1, 2014), EPA-HQ-OAR-2013-0602-24030. Likewise, Southern Company explained in its CPP comments that it has an aggressive heat rate monitoring and improvement program, incorporates efforts to restore or increase efficiency as part of its routine maintenance activities, and sets yearly heat rate recovery goals across its coal-fired fleet. Southern Company CPP Comments at 82 (Dec. 1, 2014), EPA-HQ-OAR-2013-0602-22907. In sum, the owners and operators of steam generating units routinely undertake measures to improve and maintain heat rate at their units, supporting EPA's conclusion that this system of emission reduction has been adequately demonstrated.

UARG disagrees, however, with EPA's conclusory statement in the Proposal that the mere existence of "variation in heat rates among EGUs with similar design characteristics, as well as year-to-year variation in heat rate at individual EGUs, indicate that there is potential for [heat rate improvements] that can improve CO_2 emission performance for the existing coal-fired EGU fleet." 83 Fed. Reg. at 44,755. This conclusion is based on the same fallacy that formed the basis of EPA's Building Block 1 analysis in the CPP, which UARG highlighted in its comments on the CPP proposal, *see* UARG CPP Comments at 221 (Dec. 1, 2014), EPA-HQ-OAR-2013-0602-22768. The fact that observed heat rate may vary among similar units, or vary from year to year at an individual unit, does not indicate that the steam generating unit is not being properly operated or maintained to optimize its efficiency, or that the unit's owner or operator can take steps to reduce that variability and improve the unit's heat rate. To the contrary, heat rate can vary for a wide range of reasons, many of which are entirely beyond the control of the unit's owner or operator.

Indeed, contradicting the suggestion that the fleet's heat rate variability means heat rate improvements are available at any individual unit, the Agency acknowledges that "[g]eography and elevation, unit size, coal type, pollution controls, cooling system, firing method and utilization rate are just a few of the parameters that can impact the overall efficiency and performance of individual units." 83 Fed. Reg. at 44,755. Changes in these factors can impact a unit's heat rate in ways that the owner or operator simply cannot control. For example, the quality and characteristics of coal delivered to the unit can fluctuate based on the qualities of different seams the coal supplier may be developing at its mine. Likewise, one of the most powerful factors driving a utility boiler's heat rate is its operating load. As EPA has acknowledged, these units have higher heat rates when operating as load following units and during periods of startup and shutdown. *E.g.*, EPA, Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units, GHG Abatement Measures at 2-5, 2-21 (Sept. 16, 2014) (clarified version), EPA-HQ-OAR-2013-0602-17180 ("GHG Abatement Measures TSD"). Year-to-year variability in a unit's heat rate may simply reflect changes in its utilization, which is driven primarily by market conditions outside of the unit owner's control. *See* UARG CPP Comments at 216-17, UARG ANPR Comments at 38-39. Accordingly, the existence of heat rate variability is not a valid indicator of the need or opportunity for significant improvement in a unit's heat rate.

Notwithstanding the inherent variabilities, some units will have the ability to improve their heat rate (and thus their CO_2 emission rates)—although the potential for improvement will "vary considerably at the unit level," 83 Fed. Reg. at 44,755—and that owners and operators of coal-fired utility boilers can (and do) take steps to maintain their heat rate to minimize degradation over time. Section 111 emission standards based on implementation of heat rate improvements will require that a unit must meet those emission standards on a continuous basis. Because the efficiency of a steam generating unit or natural gas combined cycle ("NGCC") unit will inevitably degrade over time, heat rate-based limits must account for that degradation. *See, e.g.*, UARG CPP Comments at 214-15. EPA has recognized this on several previous occasions. For example, in the 2015 NSPS, EPA set the performance standard for new base load gas-fired combustion turbines at 1,000 lbs CO_2/MWh-g, even though EPA noted that the six newest turbines "all have maximum 12-operating-month emission rates of less than 950 lb[s] CO_2/MWh-g" to incorporate "a significant compliance margin for any future degradation." 80 Fed. Reg. at 64,618. In addition, EPA's Environmental Appeals Board upheld a PSD permit issued by the State of Massachusetts to a new NGCC facility that accounted for efficiency degradation in setting the facility's GHG BACT limit. *In re Footprint Power Salem Harbor Dev., LP*, PSD Appeal No. 14-02, 2014 WL 11089298, at *9 (EAB Sept. 2, 2014) (permit "appropriately accounted for the degradation of turbine equipment over time that can lead to efficiency losses that directly impact greenhouse gas emissions").

In light of this degradation, where a state determines that no further heat rate improvements are appropriate for a unit and imposes a standard based on "business as usual," *see* 83 Fed. Reg. at 44,766, the unit will still need to have a plan to maintain the efficiency of its operations to avoid heat rate increases that could jeopardize compliance with its CO_2 emission limit. The compliance burden is even more significant for units that must meet a standard based on additional heat rate improvement measurements from the candidate technologies list that the state determines are appropriate.

In the 2015 NSPS, EPA found that a standard of performance based on efficient operation of the steam generating unit was appropriate for existing steam generating units that are modified, concluding that "[i]in light of the limited opportunities for emission reductions from retrofits, these reductions [resulting from efficiency improvements at the individual unit] are adequate." 80 Fed. Reg. at 64,599. The Agency noted the "inherent constraints" faced by modified sources as compared to new steam generating units. *Id.* at 64,600. The considerations that drove EPA's approach to modified units in the 2015 NSPS apply with even greater force to existing steam generating units that are *not* modified. The diversity of unit characteristics and operating profiles, as well as "limited opportunities for emission reductions," suggest that a similar unit-specific efficiency approach is appropriate here. *Id.* at 64,599.

In the Proposal, EPA responds to concerns that selecting heat rate improvements as the BSER for existing coal-fired utility boilers will yield a "rebound effect," in which some units' annual CO_2 emissions increase—even as their CO_2 emissions per unit of output decrease—due to greater annual utilization. 83 Fed. Reg. at 44,756 n.17, 44,761. The Agency concludes that its proposed BSER is nonetheless appropriate because its modeling results show the system-wide emission decreases from greater efficiency will outweigh any potential system-wide increase in annual emissions from greater utilization of some units. *Id.* EPA is correct that commenters' concerns about a potential rebound effect do not disqualify heat rate improvements as the BSER for coal-fired units for this and other reasons.

As an initial matter, it is true that there is no basis to conclude a standard based on improving units' efficiency will cause overall emissions from those sources to increase. Although reducing heat rate may make some steam generating units marginally less costly to operate, other designated facilities in the system will also experience these marginal improvements. In any event, it is far from certain that increased utilization at these units will come at the expense of lower-emitting resources like NGCC units or renewable assets. Instead, to the extent any steam generating unit is dispatched more due to its greater efficiency, it will most likely come at the expense of *less efficient steam generating units*, thus lowering the overall CO_2 emissions from the source category. Moreover, because CO_2 is a globally mixing pollutant with no direct local impacts, the change in any individual unit's total CO_2 emissions is less relevant than the emissions from the source category overall. Further, other regulatory programs are in place to limit the environmental impact of any increases in other emissions from individual steam generating units, such as the Cross-State Air Pollution Rule

("CSAPR"), the national ambient air quality standards ("NAAQS") program, the Mercury and Air Toxics Standards ("MATS"), and others.

More importantly, section 111 standard setting is not driven by achieving a desired amount of overall emission reductions. Unlike some other CAA provisions, such as those governing the NAAQS program and Title IV's Acid Rain Program, section 111 is a performance and technology-based program that is not driven by achieving specific emission reduction goals. Whereas the NAAQS provisions authorize EPA (working with states) to develop emission reduction standards to achieve health- and welfare-based goals, *see generally* CAA §§ 108-110, and Title IV mandates specific overall annual reductions to address acid deposition, *see generally id.* §§ 401-416, section 111 authorizes EPA to adopt only standards of performance that reflect the emission limitations associated with applying the "best system of emission reduction"—regardless of what overall emission reductions that "best system" would yield, *id.* § 111(a)(1). To be sure, courts have allowed EPA to consider the potential emission reductions (among other factors) when determining which of the available, adequately demonstrated systems of emission reduction is "best." *Sierra Club v. Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981). But once EPA has identified the best system of emission reduction for a source category, it is limited (or in the case of section 111(d), states are limited) to adopting emission standards that are "achievable" by sources applying that system, taking into account cost, nonair quality health and environmental impacts, and energy requirements. CAA § 111(a)(1). The Agency or a state cannot require more than is achievable through application of the best system, even if the resulting overall emission reductions are less than the standard-setting agency would prefer as a matter of policy.

Moreover, section 111 specifies that standards of performance must take the form of "emission limitation[s]," rather than "emission reductions." *Id.* §§ 111(a)(1), 302(k). When promulgating the Subpart B regulations in 1975, EPA envisioned and explained that section 111(d) standards would focus on the "control" of emissions of designated pollutants rather than their "reduction." *See generally* 40 Fed. Reg. 53,340 (Nov. 17, 1975) (titled "State Plans for the *Control* of Certain Pollutants from Existing Facilities") (emphasis added). Accordingly, with the exception of work practice standards adopted under section 111(h), a section 111 "emission limitation" almost always is expressed as an emission "rate" of some kind. *See* CAA § 302(k) (defining "emission limitation" in relevant part as something that "limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis"); 40 C.F.R. § 60.21(f) (defining Subpart B use of term "emission standard" as "setting forth an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications for control of air pollution emissions"); *id.* § 60.24(b)(1) ("Emission standards shall either be based on an allowance system or prescribe allowable rates of emissions except when it is clearly impracticable.").

In other words, the "degree of emission limitation achievable" need not represent a reduction from current emission rates or yield any reduction in overall emissions from sources or from the source category overall. In fact, EPA recognized this in the CPP, stating:

> [N]othing in [section 111] requires a particular amount—or, for that matter, any amount—of emission reductions from each and every existing source. That the "standard of performance" is defined on the basis of the "degree of emission limitation achievable through the application of the [BSER]" does not mean that each affected EGU must achieve some amount of emission reduction…. Indeed, *any emission rate-based standard may not necessarily result in emission reductions from any particular affected source (or even all of the affected sources in the category)* as a result of the ability of the particular source (or even all of them) to increase its production and, therefore, its emissions, even while maintaining the required emission rate.

80 Fed. Reg. 64,662, 64,779 (Oct. 23, 2015) (emphasis added). Likewise, EPA finalized its 2015 NSPS for new, modified, and reconstructed EGUs despite concluding that it would achieve "negligible" or "minimal" CO_2 emission reductions, if any. RIA for New, Modified, and Reconstructed EGUs at 4-20, 6-2.

In sum, because section 111 does not require that standards of performance based on the BSER actually yield any specific reduction in a unit's or source category's total emissions, any potential rebound effect (to the extent it exists at all) would not undermine EPA's Proposal. UARG agrees with EPA that the projected "emission reductions required from state plans [under the Proposal] are the appropriate amount for a 111(d) rule"—not because of their magnitude, but because they reflect the degree of emission limitation achievable through application of the BSER at individual units. 83 Fed. Reg. at 44,749. Heat rate improvements are the best system of emission reduction that has been adequately demonstrated for existing coal-fired utility boilers, and their implementation has the potential to significantly improve the CO_2 emissions performance of those units.

Finally, UARG notes its agreement with the Proposed ACE Rule that Building Block 1 of the CPP does not represent a valid application of the BSER selected in this Proposal and cannot be adopted as a replacement to the CPP. *Id.* at 44,756 ("EPA believes that building block 1, as constructed in CPP, does not represent an appropriate BSER, and ACE better reflects important changes in the formulation and application of the BSER in accordance with the CAA."). UARG's reasons for opposing a Building Block 1-only replacement to the CPP were described in its comments on the ANPR and are incorporated here by reference. *See* UARG ANPR Comments at 28-35.

2. EPA's List of Candidate Technologies Is a Reasonable Approach to Representing the Heat Rate Improvements that Constitute BSER.

a. Comments on decision to establish a candidate technologies list

For the purposes of applying the BSER to designated facilities in state plans, EPA has proposed to create a list of "candidate technologies" that best represent the BSER of heat rate improvements. 83 Fed. Reg. at 44,756. States would be required to consider the potential for implementation of each of these candidate technologies when developing standards of performance for individual units. *Id.* Provided a state has considered the applicability of these candidate technologies at the unit, it is not required to consider whether other heat rate improvements could be implemented at the unit in setting the standard.

UARG supports EPA's proposed use of a candidate technologies list to represent the BSER for the purposes of state standard-setting. The Agency's proposed approach is a reasonable method of ensuring that state standards conform to the statutory requirements for a standard of performance while minimizing the administrative burden on states in developing their plans. The Proposed ACE Rule properly assigns states the role of establishing standards of performance applicable to individual designated facilities and recognizes the need for states to develop unit-specific standards of performance in light of the significant heterogeneity in the country's coal-fired utility boiler fleet. *See* Section III.A *infra*.

Because dozens of designated facilities may require a unit-by-unit analysis in a state, and the universe of heat rate improvement measures is broad (EPA's ANPR listed 46 different heat rate improvement technologies or practices for consideration by commenters, 82 Fed. Reg. 61,507, 61,514-15 Tbls. 1 & 2 (Dec. 28, 2017)), states would not be required to consider the applicability of every possible heat rate improvement measure to every designated facility within their borders. To avoid administrative burdens that could make implementation of the ACE Rule unworkable, EPA's proposed candidate technologies list will focus the states' standard-setting analysis on those heat rate improvements that can have the most significant impact on coal-fired utility boilers' CO_2 emission rates and that are the most likely to be appropriate for inclusion in setting an achievable standard of performance in light of their costs and benefits. As discussed in Section II.A.3 below, certain heat rate improvement measures were properly excluded from EPA's proposed candidate technologies list. These measures typically have only negligible CO_2 emission rate reduction benefits, either in absolute terms or in comparison to their implementation costs; affect only net, rather than gross, heat rate; are experimental or otherwise not widely available for use at coal-fired utility boilers; could harm a unit's reliability; or otherwise are unlikely to be appropriate for inclusion in standard-setting. Thus, EPA's use of the candidate technology list allows states to expend resources evaluating only the applicability, cost, and benefits of heat rate improvements that have the greatest potential for improvement, avoiding such expenditures on measures that would result in only *de minimis* reductions.

b. Comments on specific measures included on candidate technologies list (Comments C-6, C-7)

EPA proposes to include seven different heat rate improvement technologies on its list of candidate technologies for consideration in standard-setting: (1) neural network; (2) intelligent sootblowers; (3) boiler feed pump upgrade or overhaul; (4) air heater and duct leakage control; (5) variable frequency drives ("VFDs"); (6) steam turbine blade path upgrades; and (7) economizer redesign or replacement. 83 Fed. Reg. at 44,757-58. EPA also proposes to include the general category of "best operating and maintenance practices" on that list, and identifies heat rate improvement training, on-site appraisals of areas for improved heat rate performance, and improved condenser cleaning as examples of such practices. *Id.* at 44,758. UARG's consultant examined the proposed candidate technologies list and prepared a report addressing the applicability, costs, and expected benefits from each of these measures. *See* J. Edward Cichanowicz, "Review of the Environmental Protection Agency's Selection of Heat Rate Improvement (HRI) Actions as Best System of Emissions Reduction in the Affordable Clean Energy Rule" (Oct. 2018) ("Cichanowicz Heat Rate Report") (Attachment A to these comments).

At the outset, UARG notes that some of the listed candidate technologies are capable of improving only net heat rate, not gross heat rate. Specifically, the purpose of overhauling or upgrading electric boiler feed pumps and installing VFDs where applicable at a boiler is to reduce auxiliary load at the plant, ensuring that a greater portion of the electricity produced by the generator is sold to the grid rather than used on-site. These technologies are not capable of reducing the unit's gross heat rate by improving the rate at which thermal energy produced by the utility boiler is converted to electrical energy. As discussed in Section III.E below, it would be inappropriate for state plans developed under the ACE Rule to include standards of performance expressed in terms of net output, i.e., as limiting CO_2 emissions in lb/MWh-net. Determining compliance with net output-based emission standards for individual units at a plant would require the installation of costly new monitoring equipment and would likely be inefficient and unworkable, needlessly hindering implementation of the ACE Rule. Because state plan standards of performance should be expressed in terms of gross output, electric boiler feed pumps and VFDs should be removed from EPA's candidate technologies list because they do not impact a unit's gross heat rate and will not be relevant in state standard-setting.[4] Further, to the extent that any of the remaining candidate technologies on the list may affect both gross *and* net heat rate, EPA should clarify that states are to consider only the improvements these measures offer for thermal efficiency (i.e., gross heat rate) in setting standards of performance for units and not any benefits these measures offer for reducing auxiliary load (i.e., improving net heat rate).

UARG's consultant generally concurs with EPA's estimated ranges of heat rate improvement potential and cost provided for each listed candidate technology, which are drawn primarily from analysis prepared by Sargent & Lundy, Sargent & Lundy LLC, SL-009597, "Coal-Fired Power Plant Heat Rate Reductions" (Jan. 22, 2009), EPA-HQ-OAR-2017-0355-21171 ("Sargent & Lundy"), although for some technologies UARG concludes that those ranges should be extended to encompass estimates from other sources. Cichanowicz Heat Rate Report at 13; *see* 83 Fed. Reg. at 44,757 Tbl. 1 & 44,759 Tbl. 2. UARG notes, however, that defining the outer limits of

[4] In the event EPA disagrees and decides that net output-based standards are appropriate for inclusion in a satisfactory state plan, this argument for removing VFDs and boiler feed pump upgrades from the candidate technologies list would no longer apply.

these ranges is less significant than recognizing what unit-specific factors will determine where each coal-fired utility boiler falls within that range. The heat rate improvement potential of any project will vary significantly based on the condition, operating characteristics, design, and other factors unique to each unit. For any particular heat rate improvement technology, the upper limit of EPA's estimated ranges of benefit will generally be attainable only for units that have severely degraded or outdated equipment that has not been maintained regularly. In most cases, the potential heat rate improvements will cluster at the low end of EPA's estimated ranges. Moreover, as noted in Section III.A, many heat rate improvement measures do not provide additive benefits, meaning that the potential improvement available from a particular project may depend on whether and which other projects will also be carried out at the unit. Similarly, the costs of implementing each candidate technology will vary from unit-to-unit depending on the utility boiler's design, site layout, operating characteristics, and other factors. In particular, a measure's net costs after considering savings from reduced fuel use will depend heavily on the unit's fuel cost and expected future utilization. In light of these factors affecting the costs and benefits of implementing any particular heat rate improvement measure at a unit, EPA should ensure that its emission guidelines require states to conduct unit-specific inquiries when determining whether and how to account for any of these candidate technologies when developing a standard of performance for a unit. It would not be appropriate for a state to simply assume that the costs and benefits for a particular technology will fall roughly in the middle of EPA's estimated ranges.

UARG offers the following additional comments on the specific candidate technologies listed in the Proposal:

Neural networks/Intelligent sootblowers: The Proposal lists these heat rate improvement measures together as a single "measure" with combined estimates for heat rate improvement potential and cost. *See* 83 Fed. Reg. at 44,757 Tbl. 1 & 44,759 Tbl. 2. Although these technologies are capable of being deployed together, however, they do not have to be, and in some cases, it may be appropriate for a coal-fired utility boiler to implement neural network systems but not intelligent sootblowers (or vice versa). Cichanowicz Heat Rate Report at 13. Accordingly, UARG suggests that EPA disaggregate its analysis of these technologies, including the estimated costs and heat rate improvement potential of each.

For both neural networks and intelligent sootblowers, some units may already be equipped with similar technologies that achieve substantially the same heat rate improvements. With respect to neural networks, some coal-fired utility boilers may already utilize software optimization methods that do not employ the same "self-learning" features of a neural network but that can still use predictive control, conventional optimization methodologies, chaos theory and other approaches to optimize the unit's performance. *Id.* at 13-14. Likewise, some units may already be equipped with alternative boiler cleaning devices that can be deployed "intelligently," such as water cannons. *Id.* at 15. If a coal-fired utility boiler is already equipped with one of these equivalent alternative systems, it cannot realize meaningful improvements in heat rate by also implementing these measures, and states should not find them "appropriate" for application to the unit in standard-setting.

EPA estimated the range of combined potential heat rate improvements from installing a neural network and intelligent sootblowers at 0.3-1.4 percent, based on Sargent & Lundy estimates of 0-150 Btu/kWh from neural networks and 30-150 Btu/kWh from intelligent sootblowers. 83 Fed. Reg. at 44,757 Tbl. 1; Cichanowicz Heat Rate Report at 14, 15. UARG's previous analyses estimate that neural networks are only capable of improving heat rate by 20-40 Btu/kWh, with the largest benefits accruing to units that operate in frequent cycling mode, have a large generating capacity, or rely on a large number of subordinate systems whose operation can be adjusted as load changes. Cichanowicz Heat Rate Report at 14. For intelligent sootblowers, previous analyses by UARG and the Electric Power Research Institute ("EPRI") have estimated heat rate improvement benefits of 30-100 Btu/kWh and 70 Btu/kWh, respectively. *Id.* at 15. The greatest benefits of intelligent sootblowing will occur at units with a high rate of fouling on heat transfer surfaces, such as units that were designed to combust bituminous coal but now use Powder River Basin coal, while lower or negligible benefits are expected for units that already use conventional sootblowing and can readily maintain clean boiler surfaces. *Id.*

Boiler feed pump: As noted above, because upgrading an electric boiler feed pump impacts only net heat rate, it should be excluded from the candidate technologies list.[5] If EPA does not remove this measure from the list, however, UARG notes that the highest benefits in EPA's estimated range will accrue only to older units that have operated at significant duty, exposing their boiler feed pump components (e.g., impellors, bearings, seals, and other high wear parts) to substantial wear. *Id.* at 16. Units that are newer or have had less intense utilization will see lower benefits from replacing boiler feed pump parts.

Air heater and duct leakage control: UARG's consultant notes that the applicability of air heater seals is largely limited to air heaters that employ the Ljungstrom design, as tube-type and Rothemule-type air heaters do not employ the proper kind of seal. *Id.* at 17. Low-leakage seals are also not feasible on air heaters where the heat exchange baskets have been compromised. *Id.* For a new unit, some air leakage of roughly 4-6 percent of flue gas flow volume is typical. *Id.* at 16. Thus, implementing this measure is unlikely to reduce leakage beyond that level, and the greatest heat rate improvement potential will be observed for units where leakage is significantly greater.

VFDs: As noted above, because installation of VFDs impacts only net heat rate, it should be excluded from the candidate technologies list. If EPA does not remove this measure from the list, however, UARG notes that the highest benefits in EPA's estimated range will be available only to

[5] However, upgrades to a steam-driven boiler feed pump can improve gross heat rate. Cichanowicz Heat Rate Report at 16.

units that devote a significant amount of their operations to cycling or part load, because VFDs operate by reducing the auxiliary power used to drive process equipment at less than full load. *Id.* at 17-18.

<u>Steam turbine blade path upgrade</u>: The scope of work involved in a steam turbine blade path upgrade can vary based on the turbine and the upgrade package offered by the supplier. *Id.* at 18-19. Potential elements of a blade path upgrade project could include improving one or all of the high-pressure, intermediate-pressure, or low-pressure steam expansion sections; replacing original components with more advanced materials; and implementing measures that improve performance at off-peak loads, such as partial arc steam admission. *Id.* The scope of work involved will influence the cost and the potential heat rate improvement for a particular unit. The potential improvement for a coal-fired utility boiler will also depend on the pre-project condition of the existing steam turbine, including its design, age, materials, and maintenance history. For many units, implementation of this measure may not be appropriate due to the high capital costs, which Sargent & Lundy estimate could reach up to $20 million for a 500 MW unit. *Id.* at 18.

UARG notes that some analyses performed by the National Energy Technology Laboratory ("NETL") and EPRI estimate the potential heat rate improvement from a turbine upgrade to be greater than the 100-300 Btu/kWh cited in Sargent & Lundy's study, with analyses at some units ranging as high as 581 or 400 Btu/kWh. *Id.* at 19. The scope of work examined in the NETL and EPRI studies, however, exceeded the steam turbine blade path to include other components at the facility, such as improved main shaft bearings. Accordingly, those estimates should not be considered representative for the type of project described on EPA's proposed candidate technologies list.

<u>Economizer redesign or replacement</u>: This measure is best suited for units that have switched to combusting coals of different rank than was assumed in the utility boiler's original design. *Id.* at 19. In addition, UARG notes that the changes a coal-fired utility boiler can make at its economizer may be limited by the need to maintain appropriate temperatures at a downstream selective catalytic reduction ("SCR") system for nitrogen oxides ("NOx") control. *Id.* at 19-20.

<u>Heat rate improvement training and on-site appraisals</u>: While UARG agrees that owners and operators of coal-fired utility boilers may be able to identify additional opportunities for improving heat rate by implementing targeted training programs and performing regular on-site appraisals, the potential impact of those steps on a unit's heat rate are far too variable and speculative to be used in standard-setting. *See id.* at 20. No state has the foresight to determine what opportunities for heat rate improvement a coal-fired utility boiler's owner might be able to find during some future site appraisal, or to then set an emission standard based on the expected emission reductions resulting from those opportunities. Accordingly, states should not be required to consider these measures in developing state plans.

<u>Improved condenser cleaning</u>: The Proposal does not provide estimated benefits or heat rate improvement potential for improved condenser cleaning specifically. UARG's consultant estimates that an integrated program of cleaning both steam-side and cooling water-side surfaces within the condenser can yield heat rate improvements of 30-70 Btu/kWh, at a cost of approximately $60,000 per year, for a 500 MW unit. *Id.* at 21.

3. EPA Properly Excluded Other Heat Rate Improvement Measures from its Candidate Technologies List. (Comments C-6, C-7)

EPA's proposed candidate technologies list is not an exhaustive recitation of every technology or operating practice that might conceivably improve a utility boiler's heat rate. The Agency's decision, however, to exclude other heat rate improvement measures from the list is reasonable. Each of these excluded measures is inconsistent with application of the BSER for utility boilers for one or more reasons, and states therefore should not be required to consider those measures as part of their application of the BSER to individual units.

The Cichanowicz Heat Rate Report examined several alternative heat rate improvement measures that were not included on the EPA's candidate technologies list. *Id.* at 22-28. Many of these measures were drawn from Tables 1 and 2 of the ANPR, *see* 82 Fed. Reg. at 61,514-15, and UARG explained in its comments on that ANPR why some of those measures were not appropriate as the basis for section 111 standards of performance, *see* UARG ANPR Comments at 40-43. In general, the heat rate improvement measures discussed below—and which were properly excluded from the candidate technologies list—involve unreasonable costs, affect net but not gross heat rate, have potential reliability impacts, could impact control of other emissions, or are not commercially demonstrated. Some excluded heat rate improvement measures suffer from several of these defects. Each of these defects is discussed below.

a. Measures that are unreasonably costly (Comments C-6, C-7)

For some projects, the cost required to achieve a reduction in heat rate is unreasonably high, particularly when viewed as a function of the efficiency improvements gained and the time required to cover those costs through reduced fuel expenditures. UARG's consultant analyzed the heat rate improvement measures included on EPA's candidate technologies list and found that while the costs and resulting heat rate improvement from implementing each measure will vary from unit to unit, those costs are generally reasonable when viewed in light of typical ranges of associated CO_2 reductions and avoided fuel costs. Cichanowicz Heat Rate Report at 9-21. By contrast, many of the projects excluded from the candidate technologies list would require significant capital costs just to achieve fairly minor improvements in efficiency. Some would have to provide heat rate improvement benefits for 20 or more years in order to justify their cost through reduced fuel expenditure, which is an unreasonable payback period given that (a) the benefits of most heat rate improvement measures degrade within a few years, and (b) many coal-fired utility boilers have remaining useful lives that are less than 20 years.

For example, a utility boiler could potentially reduce its heat rate by up to 50-100 Btu/kWh by upgrading its coal pulverizers to improve particle size distribution. *Id.* at 23. This improvement is similar to the range estimated for implementation of intelligent sootblowers at a unit. *Id.* at 15. The capital cost of upgrading these coal pulverizers is high, however, at $18.4 million for a 500 MW unit, compared to just $500,000 for intelligent sootblowers at a large unit. *Id.* at 15, 23. Accordingly, even under optimistic assumptions it would take more than 20 years for a unit to recover the costs of upgrading its coal pulverizers through reduced fuel costs, as compared to just 4-5 years for intelligent sootblowers. *Id.*

Enhanced waste heat recovery is another heat rate improvement for which the costs are unreasonable in light of the potential benefits. Installing additional heat exchange surfaces in the flue gas path can require significant capital costs, and historically the resulting benefits for unit efficiency have been minimal. *Id.* at 23. Further, for most coal types, the potential for corrosion from sulfuric acid in the flue gas means that this measure must be coupled with dry sorbent injection using alkali to control the acid levels, resulting in additional ongoing operating costs. *Id.* These new operating costs overpower any savings from reduced fuel costs, meaning that this measure is not cost-effective. *Id.*

Notably, while one item on EPA's candidate technologies list is improved condenser cleaning, the owner of a utility boiler could also consider simply replacing its condenser. *Id.* at 24. A new condenser could incorporate an updated design with more advanced materials that are less prone to accumulate deposits or develop leaks. The estimated capital cost, however, for a new condenser is roughly $10 million for a 500 MW plant, and the incremental heat rate improvement achieved over and above what the unit could instead obtain through improved condenser cleaning at only $60,000 per year would not be worth that expenditure. *Id.* at 21, 25. Indeed, it would take the unit at least 20 years to recover the costs of replacing its condenser. *Id.*

b. Measures that improve only net heat rate (Comments C-6, C-7, C-16)

Many of the equipment upgrades and operating practices listed in Tables 1 and 2 of the ANPR, 82 Fed. Reg. at 61,514-15, have the potential to improve an EGU's *net* heat rate by reducing auxiliary load but would have no impact on the unit's *gross* heat rate. The owners and operators of utility boilers already routinely take steps to minimize auxiliary load and improve net heat rate as a matter of standard industry practice, given the substantial incentives to maximize the amount of electricity produced that is sold to consumers. As discussed in Section III.E below, UARG believes that any output-based standards of performance adopted in state plans according to this rule should be expressed only in terms of gross output. Accordingly, any measures that would improve only net heat rate—such as replacing centrifugal flue gas fans with axial fans, *see* Cichanowicz Heat Rate Report at 25—would not be relevant to standard-setting and are properly excluded from the candidate technologies list.

c. Measures with potential reliability impacts (Comments C-6, C-7)

EPA has previously identified the use of advanced cooling tower packing material as a potential heat rate improvement measure. But while this upgrade does have the potential to improve heat rate, it can also present significant reliability concerns for utility boilers. Analyses by UARG and its members have shown that these advanced, high efficiency fills have proven to be problematic and are more prone to fouling, which can ultimately reduce efficiency and require shutdowns for more frequent maintenance. *See* AEP CPP Comments at 69. In fact, some units that switched to high efficiency fills have switched back to standard fills and seen heat rate improvements. *Id.*

In addition, the costs of this measure can also be disqualifying. While the packing material change out may cost $3 million and incur annual operating costs of $125,000, the actual efficiency improvement observed is highly variable and may be negligible in some cases. Cichanowicz Heat

Rate Report at 24. As a result, it would take over 20 years for the unit to recover the cost of this measure through reduced fuel expenditures.

d. Measures aimed at emission control systems (Comments C-6, C-7)

UARG believes that heat rate improvement measures focused on utility boilers' emission control systems are unlikely to be useful in achieving CO_2 emission standards and are properly excluded from the candidate technologies list. First, most heat rate improvements targeting emission control systems are intended to reduce auxiliary load and improve net heat rate, which would not be reflected in a CO_2 emission standard based on gross output. *Id.* at 27. Second, these measures present a risk of impacting the effectiveness of the unit's emission control systems, potentially causing emissions of other pollutants to increase. *Id.* For example, one of the flue-gas desulfurization ("FGD") improvements discussed in the Sargent & Lundy report involves shutting off a sprayer in an FGD module for units that are operating below applicable sulfur dioxide ("SO_2") limits in order to reduce auxiliary load but doing so would likely increase the unit's SO_2 emissions. Sargent & Lundy at 5-3.

e. Measures that have not been sufficiently commercially demonstrated (Comments C-6, C-7)

Finally, some heat rate improvement measures are still unproven and would be inappropriate to include in the Proposed ACE Rule's standard-setting process for states. The ANPR listed coal drying as one potential efficiency measure for coal-fired utility boilers. But use of coal drying technology is still in an experimental stage in the United States, and some technical and safety issues have yet to be resolved. Cichanowicz Heat Rate Report at 22. Only one domestic application is in operation, and it was subsidized by funding from the U.S. Department of Energy ("DOE"). *Id.* Further experience with this practice is needed before it can be considered commercially demonstrated. UARG also notes that coal drying may offer meaningful efficiency improvements only for lignite-fired units, limiting its relevance for the source category more broadly.

Similarly, the use of solar energy systems to pre-heat boiler feedwater has not been proven to meaningfully improve utility boilers' heat rates. *Id.* at 27-28. There are no commercial applications of this configuration in the United States, and estimates of the cost vary, ranging as high as $99 million for a 750 MW unit. *Id.*

4. Carbon Capture and Sequestration ("CCS") Is Not BSER. (Comment C-12)

EPA rejected the use of CCS as the BSER for coal-fired utility boilers. 83 Fed. Reg. at 44,761. The Agency noted that application of CCS at an existing unit is "significantly more expensive than alternative options for reducing emissions and may not be a viable option for many individual facilities." *Id.* EPA also solicited information on "any new information regarding the availability, applicability, costs, or technical feasibility of CCS technologies." *Id.* at 44,762.

UARG supports the Agency's decision not to identify CCS (whether "full" or "partial") as the BSER for existing coal-fired utility boilers. UARG's consultant has reviewed available information on the status of CCS technology demonstration efforts and prepared the attached report addressing new information made available since the time of EPA's CPP rulemaking. J. Edward Cichanowicz, "Demonstration Status of Carbon Capture and Sequestration (CCS) in Response to the Proposed Affordable Clean Energy (ACE) Rule" (Oct. 2018) ("Cichanowicz CCS Report") (Attachment B to these comments). That report confirms that CCS cannot serve as the basis for standards of performance under section 111 for existing coal-fired utility boilers.

In the CPP, EPA recognized that even if CCS could be considered the BSER for *new* units, *existing* units present additional challenges to CCS deployment. The Agency stated in its proposed CPP that:

> application of CCS at existing units would entail additional considerations beyond those at issue for new units. Specifically, the cost of integrating a retrofit CCS system into an existing facility would be expected to be substantial, and some existing EGUs might have space limitations and thus might not be able to accommodate the expansion needed to install CCS. Further, the aggregated costs of applying CCS as a component of the BSER for the large number of existing fossil fuel-fired steam

> EGUs would be substantial and would be expected to affect the cost and potentially the supply of electricity on a national basis.

79 Fed. Reg. 34,830, 34,857 (June 18, 2014). Relying on these concerns, EPA rejected CCS as the BSER in the final rule. *See* 80 Fed. Reg. at 64,690 (finding "the scale of infrastructure required to directly mitigate CO_2 emissions from existing EGUs through CCS can be quite large and difficult to integrate into the existing fossil fuel infrastructure"); *id.* at 64,727 (finding only "a segment of the source category may implement" CCS); *id.* at 64,751 ("While the EPA also considered measures such as CCS retrofits for all fossil-fired EGUs or co-firing at all steam units, the EPA determined that these costs were too high when considered on a sector-wide basis.").

Those conclusions remain valid. CCS has not been adequately demonstrated for the source category, is exorbitantly costly, is not available in many parts of the country, and implicates several unresolved legal and technical issues with respect to transportation and long-term storage of capture CO_2.[6]

Setting aside the issue of whether carbon capture technology has been adequately demonstrated, CCS cannot be implemented without a suitable site for carbon storage or reuse that eliminates any emissions or limits CO_2 emissions to the ambient air on a continuous basis. Sequestration and storage opportunities are available only at plant sites near CO_2 transport pipelines and geologically acceptable repositories, such as deep saline reservoirs. These potential repository sites are not evenly distributed throughout the United States, and many locations throughout the country lack suitable geological conditions for carbon storage. Cichanowicz CCS Report at 5-1 to 5-4.

The DOE's 2012 "Atlas" of potential storage capacity shows that ten states have either "zero" CO_2 storage capacity or have yet to be assessed, while another five appear capable of serving

[6] For similar reasons, UARG encourages EPA to revisit its conclusion in the 2015 NSPS that partial CCS has been adequately demonstrated for new coal-fired utility boilers.

just a few 500 MW plants, leaving 30 percent of the states underserved. *Id.* at 5-1; DOE, Office of Fossil Energy, NETL, THE UNITED STATES 2012 CARBON UTILIZATION AND STORAGE ATLAS, FOURTH EDITION (undated), https://www.netl.doe.gov/File%20Library/Research/Coal/carbon-storage/atlasiv/Atlas-IV-2012.pdf ("DOE Atlas"). A 2013 assessment by the U.S. Geological Survey further concludes that fully 2/3 of the technically accessible storage resources in the United States are confined to the Coastal Plains region, with 91 percent of that total limited to a single basin. U.S. Geological Survey, Circular 1386 Version 1.1, *National Assessment of Geologic Carbon Dioxide Storage Resources – Results*, at 3 Fig. 1, 15 (Sept. 2013), EPA-HQ-OAR-2013-0495-0044 ("USGS Assessment"). Another tenth of the nation's potential storage capacity is in Alaska, almost all of which is confined to the remote North Slope. *Id.* None of these estimates considered economic viability or lack of accessibility to storage resources due to land-management or regulatory restrictions. *Id.* at 9. Many of the basins contained in the assessed total for the western U.S. contain freshwater, which would restrict their use for CO_2 storage. *Id.* at 15. In contrast, the entire Eastern Mesozoic Rift Basin region, which includes several major metropolitan areas along the Eastern seaboard where many existing coal-fired utility boilers are located, contains less than 1 percent of the nation's storage capacity. *Id.* at 3 Fig. 1.

Furthermore, the estimates presented in the DOE and USGS reports are uncertain, "high level" assessments of potential storage resources, and the adequacy of any particular site for CO_2 storage depends on site-specific characterization and testing. Cichanowicz CCS Report at 5-1. Actual storage capacity is likely to be significantly lower than the estimates presented in these studies. A formation may have one or more fractures in the caprock or may have well penetrations. A site may have sufficient porosity but low permeability. Current information in most cases would not be sufficient to show whether CO_2 is likely to settle in a broad or narrow depth range, a question that is important to resolve in order to determine how the CO_2 plume will spread and to address displacement of underground fluids. Settlement of CO_2 and displacement of underground fluids factor into the property rights that must be pre-arranged for sequestration. These critical issues require costly, potentially time-consuming research and resolution: it can take five years or more to evaluate a site for CO_2 storage potential. *Id.* at 5-2. If the site proves to be unsuitable for storage after a company has invested years of effort and millions of dollars into the evaluation, the company may have to begin the process all over again with additional time and money.

Suitable sites for enhanced oil recovery ("EOR") are similarly limited and uncertain. Evidence shows that EOR sites are unevenly distributed across the country. While some Midwestern and Gulf Coast states may have abundant sites, the Pacific Northwest and much of the eastern seaboard have limited capacity. *Id.* at 5-3. Nineteen states either have not been assessed or feature "zero" EOR storage capacity or can accommodate only a small number of coal-fired utility boilers' captured CO_2. *Id.* The DOE estimates that overall EOR capacity for captured CO_2 is only about 10 percent of the capacity estimated for deep saline sequestration. *Id.* And as with sequestration, several years of subsurface feature characterization may be required before a site can be assessed as suitable for EOR. *Id.* These limits are particularly significant in light of the fact that the only commercial utility applications of CCS to date have had to rely on EOR in order to be cost-justified.

There are also numerous unresolved permitting and regulatory issues that present obstacles to CO_2 transport and storage with CCS. *See* UARG, Comments on EPA's Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units; Proposed Rule, 79 Fed. Reg. 1430 (Jan. 8, 2014) at 58-64 (May 9, 2014), EPA-HQ-OAR-2013-0495-10938 ("UARG NSPS Comments"). Issues regarding pipeline siting and construction, interstate transport and safety issues, property rights of pore space owners, and long-term closure are of particular concern. Property rights issues may involve negotiating with multiple property owners over pore space acquisition and access to surface sites for well monitoring. Cichanowicz CCS Report at 5-4.

But even if concerns regarding the availability and cost of CO_2 transport and storage can be resolved, EPA cannot show that the technology required for capturing CO_2 from an existing coal-fired utility boiler's flue gas stream has been adequately demonstrated. At the outset, UARG notes that there is only one coal-fired utility boiler operating in the United States with CCS, and EPA is prohibited from considering that project to support a finding of "adequate demonstration" under section 111 by the Energy Policy Act of 2005. NRG's Petra Nova project, which treats a 240 MW-equivalent flue gas flow from a 654 MW boiler at NRG's W.A. Parish plant in Texas, began operating a post-combustion CCS facility in January 2017. *Id.* at 3-7. The Petra Nova project received funding, however, under the Energy Policy Act's Clean Coal Power Initiative ("CCPI"). 80 Fed. Reg. at 64,551. The plain language of the Energy Policy Act unambiguously prohibits EPA from considering technology that is used at a facility receiving CCPI assistance as "adequately demonstrated" technology under CAA section 111:

> No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be … adequately demonstrated for purposes of section 111 of the Clean Air Act (42 U.S.C. 7411)….

Energy Policy Act of 2005, Pub. L. No. 109-58, § 402(i), 119 Stat. 594, 753 (2005) ("Energy Policy Act"), codified at 42 U.S.C. § 15962(i). Congress included this provision because CCPI funding is limited, *by definition*, to technologies that have not been adequately demonstrated. The CCPI program funds projects that "advance efficiency, environmental performance, and cost competitiveness *well beyond* the level of technologies that are *in commercial service* or *have been demonstrated* on a scale" that the DOE "determines is sufficient to demonstrate that commercial service is viable as of [the date of enactment]." 42 U.S.C. § 15962(a) (emphases added). In other words, the stated purpose of the CCPI program is to promote the development of technologies that are not yet adequately demonstrated. Moreover, because a statutory prerequisite for a technology to receive CCPI funding is that it is not in "commercial service" or "viable," EPA has an extra hurdle to prove that any level of emission reduction achieved by CCPI-funded facilities is now viable and adequately demonstrated.

While CCS is a promising technology for the future, it is currently unproven and exorbitantly costly, making it inappropriate for widespread application at utility scale. EPA has recognized that "CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls." GHG Permitting Guidance at 42. Further, there are "significant logistical hurdles" to installing and operating a CCS system that "set[] it apart from other add-on controls that are typically used to reduce emissions…." *Id.* at 36. Utility industry experience with CCS to date is far more limited than the deployment of relevant controls for SO_2 and NOx when those controls were used as the basis for NSPS. *See* UARG NSPS Comments at 66-68. And the little experience that has been gained—at just two demonstration projects and a handful of pilot plants—is not sufficient to support a BSER determination.

Only two utility boilers in North America employ a system of post-combustion CO_2 capture, the primary form of CCS technology discussed for potential application at coal-fired utility boilers. Cichanowicz CCS Report at 3-4 to 3-7. One, NRG's Petra Nova project, is designed to provide 90 percent capture from a 240 MW-equivalent slip stream at the W.A. Parish facility in Texas. *Id.* at 3-7. As discussed above, the Energy Policy Act bars EPA from considering experience at that plant to support a finding that CCS has been adequately demonstrated. 42 U.S.C. § 15962(i). But even absent this statutory prohibition, the Petra Nova facility's substantial reliance on federal subsidies and special financing provided by the Japanese government's public financial institution to cover its capital cost of approximately $1 billion prevent this project from contributing to the "adequate demonstration" of CCS for the utility boiler fleet generally. *See id.* An adequately demonstrated system must be one that is available at reasonable cost, and these special economic incentives—which were a key part of the company's business case for pursuing the project—will not be available for all coal-fired or possibly even any other units. Further, experience at Petra Nova does not support widespread application of CCS because the project is only economical if NRG is able to sell captured CO_2 for EOR at a price of at least $50 per barrel. *Id.* Opportunities for EOR are limited to just a few areas of the country, and while Petra Nova's location near a willing purchaser for captured CO_2 helps to make CCS economical under the plant's unique circumstances, for most utility boilers the costs of transporting captured CO_2 to suitable EOR sites will be prohibitive. And in any event, the Petra Nova project has only been in operation since January 2017. Several years of operation under variable load conditions are needed before EPA can draw conclusions about the long-term performance of CCS at Petra Nova.

The other CCS installation is at Sask Power's Boundary Dam Unit 3. That project was designed to capture 90 percent of the CO_2 emitted from a 110 MW utility boiler for use in EOR at the nearby Weyburn oil fields. *Id.* at 3-4. Like Petra Nova, the Boundary Dam project relied on funding from the Canadian government for approximately 20 percent of its cost. *Id.* Further, because Sask Power is owned by the provincial government of Saskatchewan, it is able to take risks to promote and develop new technology that many private utility boiler owners cannot. The project also relies on revenue from its EOR function to mitigate those costs: less than 8 percent of its captured CO_2 has gone to deep saline formations for storage instead of EOR. And at 110 MW, Boundary Dam Unit 3 is relatively small compared to the average existing coal-fired utility boiler. Further scale-up in CO_2 capture equipment—with a corresponding increase in cost—would be necessary to apply CCS to larger units.

Boundary Dam has also been plagued by technical problems and outages resulting from fundamental problems in the design of the capture system itself, showing that more work is needed before CCS can be applied on a fleetwide scale. Sask Power has described these problems as "design defects; deficient equipment; flue gas heat losses; and amine degradation challenges." *Id.* at 3-5. Although several major issues arose at the plant, the most significant is that high flue gas temperatures and particulate content interfered with the amine-based chemical system used at Boundary Dam for separating CO_2, reducing the CO_2 capture rate and necessitating more frequent cleaning of CCS components. *Id.* Fly ash was also found to be adhering to surfaces inside the flue gas path. *Id.* As a result, the capture system only operated about 40 percent of the time during the unit's first year of operations, and CO_2 capture rates still averaged well below the design value of 90 percent for several years after operations commenced. *Id.* at 3-6. The CCS system had to be taken offline every four to five weeks to clean system components. Duckett, A., "The Privilege of Being First," The Chemical Engineer (May 1, 2018), https://www.thechemicalengineer.com/features/the-privilege-of-being-first ("Duckett Article"). These performance shortfalls are believed to have cost the company (and taxpayers) $27 million in penalties and lost revenue. *Id.* at 3-6.

Sask Power had to undertake major renovations to its CCS process in 2015 and 2017 to address these and other unanticipated problems with the system's design. The company installed a spray curtain and demister top wash spray to address particulate matter contamination and installed redundant systems to allow CCS components to be cleaned without taking the capture system offline. *See* Duckett Article. Other unanticipated changes to address CCS problems include adding activated carbon treatment to resolve unanticipated foaming in the amine solution; replacing the original steam desuperheater, which was unable to sufficiently cool the steam; replacing the amine tank; and installing new coolers on the CO_2 compressor—a project that reportedly took longer than anticipated due to the unique size and complexity of the compressor required for this CCS process.

Id.; Cichanowicz CCS Report at 3-5 to 3-6. Each of these projects added to the overall cost of the CCS system. Further, Sask Power is still trying to resolve problems with faster-than-expected degradation of its amine solution, which continues to impose elevated operating costs. *Id.* Sask Power's forecasted budget for amine in 2015 was $5 million (CAD); its actual expenses for amine amounted to $17.3 million in 2015 and $14.6 million in 2016. *Id.*

There are some indications that the supplemental projects Sask Power has undertaken have improved the performance and reliability of the Boundary Dam CCS system, although it is unclear if the plant has been able to sustain the performance benchmarks it was designed for. But nonetheless, the fundamental design problems encountered at Boundary Dam indicate that engineers are still figuring out how to apply CCS at coal-fired utility boilers. While experience at Boundary Dam may inform future demonstration projects, it is not sufficient to show CCS is adequately demonstrated.

Finally, other experience with CCS to date at small-scale pilot plants for technology validation and at non-utility applications also does not support a BSER finding. Post-combustion CO_2 capture has been tested at a few pilot plants, but these projects are an order of magnitude smaller than commercial-scale utility boilers. Although some of the host units themselves are large, they capture CO_2 from only a miniscule slip-stream of their emissions. *Id.* at 3-2 (AES Warrior Run, 18 MW-equivalent slip-stream; AES Shady Point, 16 MW-equivalent slip-stream; AEP Mountaineer, 20 MW-equivalent slip-stream; Southern Company Plant Barry, 25 MW). Significant scale-up is needed for broader application within the industry. Moreover, many of these pilot plants only tested one portion of the CCS process without demonstrating that the entire CCS process, from capture to transport to sequestration or use in EOR, can work in an integrated manner. For example, the Warrior Run and Shady Point pilot plants used captured CO_2 for on-site food production. *Id.* Post-combustion capture technology has also been implemented at some non-utility applications, such as the Searles Valley Minerals Plant and Archer Daniels Midland's Illinois Industrial CCS facility. *Id.* at

3-2, 3-7. But industrial application is qualitatively different from use of CCS at a utility boiler. Industrial processes generally operate continuously at steady state, so their carbon capture processes do not have to respond to emission fluctuations resulting from variable load. And some industrial processes simply emit CO_2 differently, making CCS easier to implement: at the Archer Daniels Midland plant, the ethanol production process inherently separates CO_2, meaning that the only additional processes required before CO_2 transport are de-watering and compression. *Id.* at 3-7 to 3-8.

Accordingly, EPA was correct to determine that CCS is not the BSER for existing coal-fired utility boilers. Nothing has occurred since the Agency last rejected CCS in the CPP that would support a finding that CCS has now been adequately demonstrated. However, individual designated facilities should remain free to pursue CCS to comply with their standards of performance if they so choose.

5. Co-Firing Alternative Fuels Is Not BSER.

EPA also determined that co-firing alternative fuels, such as natural gas and biomass, is not the BSER for existing coal-fired utility boilers. 83 Fed. Reg. at 44,762. The Agency observed that regional considerations (such as lack of access to these alternative fuels) and cost made co-firing inappropriate as the basis for a nationwide BSER. *Id.* In particular, for natural gas co-firing EPA noted that many existing coal-fired utility boilers "do not have access to natural gas transportation infrastructure and gaining access would be either infeasible (due to technical or timing considerations) or unreasonably costly," and for units that currently co-fire or have access to pipelines, "many may be capacity constrained." *Id.*

UARG agrees with EPA's conclusion. Co-firing natural gas or biomass is not a part of the BSER EPA has proposed. And it cannot be the BSER for existing coal-fired utility boilers because it would redefine the source, is not available nationwide, and would be uneconomical for many units.

EPA has solicited comment on whether "co-firing methods should be included among the list of BSER candidate technologies for states to evaluate when establishing a standard of performance for each affected source in their jurisdiction." *Id.* However, there is a fundamental defect in EPA's inquiry: co-firing cannot be "included among the list of BSER candidate technologies" because it is not part of the BSER the Agency has proposed. EPA has identified "heat rate improvement" as the BSER for existing coal-fired utility boilers. *Id.* at 44,756. But co-firing natural gas is not a heat rate improvement measure. In fact, as EPA acknowledges, co-firing natural gas in a coal-fired utility boiler will generally "*negatively impact* a unit's efficiency due to the high hydrogen content of natural gas and the resulting production of water as a combustion by-product." *Id.* at 44,762 (emphasis added); *see also* . J. Edward Cichanowicz, "Overview of Issues Presented by Natural Gas Co-Firing and Fuel Switching at Coal-Fired Electric Generating Units" at 1, 6-7 (Oct. 2018) ("Cichanowicz Co-Firing Report") (Attachment C to these comments). While co-firing natural gas is a *CO_2 emission rate reduction* measure, it is not a *heat rate improvement* measure.

Standards of performance under section 111 must reflect the degree of emission limitation achievable through application of the BSER to affected sources. CAA § 111(a)(1). The Proposed ACE Rule's approach to state plan standard-setting—in which states develop standards of performance for individual units based on what is achievable after application of a "candidate technologies" list to the source—is only permissible to the extent that the "candidate technologies" list is an accurate representation of the BSER for those sources. EPA cannot use the proposed framework to establish a regulatory regime in which states must evaluate every way in which an individual designated facility might limit its CO_2 emissions, including methods that are not part of the BSER. Here, co-firing is not part of the BSER that has been identified for coal-fired utility boilers. Rather, it is a *different* system of emission reduction—and as such, it is only relevant for section 111(d) standard-setting purposes if EPA finds that it is adequately demonstrated and selects it as BSER instead of (or at least combined with) heat rate improvement measures.

Requiring coal-fired utility boilers to co-fire or convert to alternative fuels like natural gas cannot constitute the BSER for those sources because it would "redefine the source," which is not permitted under section 111, as EPA has proposed to recognize in this rulemaking. *See* 83 Fed. Reg. at 44,752-53. As the Supreme Court held in *Utility Air Regulatory Group*, "it has long been held that BACT cannot be used to order a fundamental redesign of the facility," 134 S. Ct. at 2448, and section 111's standard-setting provisions are intertwined with the BACT provisions. EPA and the courts have frequently stated that a source owner's choice of fuel for a unit is a fundamental part of the source's design and that forcing the owner through standard-setting to switch to a different, lower-emitting type of fuel generally exceeds EPA's or the permit issuer's authority under the CAA. In the GHG Permitting Guidance, EPA stated that a BACT analysis "does not need to include 'clean fuel' options that would fundamentally redefine the source," including "those that would require a permit applicant to switch to a primary fuel type (*i.e.*, coal, natural gas, or biomass) other than the type of fuel that an applicant proposes to use for its primary combustion process." GHG Permitting Guidance at 27. EPA stated its belief that in most cases "the option of using natural gas as a primary fuel would fundamentally redefine a coal-fired electric generating unit." *Id.* Co-firing a secondary fuel that is otherwise available at the source already would likewise constitute "redefining the source" if it would "disrupt the applicant's basic business purpose." *Id.* at 27-28. This policy has been borne out in numerous decisions by EPA's Environmental Appeals Board, which has held that it is "long-standing EPA policy that certain fuel choices are integral to the electric power generating station's basic design." *In re Prairie State Generating Co.*, 13 E.A.D. at 25. Further, the Seventh Circuit recognized in *Sierra Club* that the choice of fuels is an essential part of a source's purpose and design, and that requiring a source to change its design in order to combust an alternative fuel constitutes redefining the source. 499 F.3d at 655-56.

Here, basing a standard for coal-fired utility boilers on some degree of natural gas co-firing (or even full conversion to natural gas combustion) is precisely the kind of measure that would redefine the regulated source. As discussed below, increased combustion of natural gas would change the economics of a coal-fired unit, and significant physical changes would be needed to the design of utility boilers that are not currently equipped for co-firing, including changes to the boiler itself and projects to connect the plant site to a natural gas supply. Accordingly, natural gas co-firing is not an option for the BSER.

Even setting aside the CAA's prohibition on "redefining the source" through emission standards, co-firing or converting to natural gas is not the BSER for coal-fired utility boilers because it has not been adequately demonstrated for the source category as a whole. While some individual units may have the capacity to co-fire natural gas to some degree, and may even do so already, the same is not true for the fleet generally. As EPA recognizes in the proposal, many existing coal-fired utility boilers are not connected to natural gas pipeline infrastructure. 83 Fed. Reg. at 44,762. For some of these units, due to geographical constraints or other regional issues, obtaining sufficient natural gas for co-firing is simply not feasible. Even for units that could feasibly obtain access to natural gas supply, the cost of developing a pipeline connection can be prohibitive—recent sources report that pipeline installation costs can range from several hundred thousand to over $1 million per mile. Cichanowicz Co-Firing Report at 12.

Aside from concerns about adequate natural gas supplies, co-firing or converting to natural gas at a utility boiler designed to combust coal would require changes to boiler design and equipment that could be extremely costly. A boiler may require major redesign of its convective pass to accommodate the higher firing temperatures associated with natural gas combustion. *Id.* at 10.

Changes would also be necessary for the unit's burners and its control systems. *Id.* at 8-9, 11. Increased combustion of natural gas at a utility boiler can significantly alter the unit's characteristics, in some cases even necessitating a derate in the unit's capacity because its components cannot accommodate the increased steam temperature and pressure associated with combusting natural gas at its previous maximum capacity. *Id.* at 7.

Even at coal-fired units that already combust or are capable of combusting some natural gas, there may be similar constraints on the unit's ability to implement increased co-firing. Existing pipeline infrastructure to the plant may be unable to accommodate greater gas delivery, or pipeline gas pressure may be too low to deliver additional gas to the property line. *Id.* at 14. In some cases, additional natural gas may only be available through interruptible supply contracts that allow the supplier to divert gas to other purchasers, particularly in the Northeast. *Id.* Utility boilers with interruptible gas supply contracts would not have reliable access to the gas needed to comply with a standard based on co-firing.

Accordingly, EPA was correct to conclude that co-firing alternative fuels is not the BSER for existing coal-fired utility boilers. Although sources should be free to voluntarily use this method to comply with state standards of performance, states cannot base their standards on the use of co-firing.

B. EPA Has Not Proposed BSER for Existing Gas- and Oil-Fired Steam Generating Units and Cannot Finalize Emission Guidelines for Them. (Comment C-4)

According to EPA's proposed regulatory text, the Proposed ACE Rule would apply to any existing utility boiler, regardless of the type of fuel that it combusts. *See* 83 Fed. Reg. at 44,810, Proposed 40 C.F.R. § 60.5775a. However, EPA has only proposed to identify the BSER for the subset of coal-fired utility boilers, without addressing the BSER for those that combust other fossil fuels like natural gas or oil. *Id.* at 44,756. EPA cannot finalize emission guidelines for gas- and oil-fired utility boilers until it has identified an adequately demonstrated BSER for those sources.

The narrow applicability of EPA's proposed BSER is explicit: the preamble states that "EPA is proposing to determine that heat rate improvement is the BSER for affected existing *coal-fired EGUs*." *Id.* (emphasis added). Although other portions of the preamble refer to "steam generating fossil fuel-fired EGUs" more generally, *see id.* at 44,755, the record makes clear that EPA has not considered what systems of emission reduction are adequately demonstrated, and what degree of emission limitation is achievable, for gas- and oil-fired utility boilers. EPA states that the overall purpose of the proposal is to "ensure that *coal-fired power plants* (the most [CO_2] intensive portion of the electricity generating fleet) address their contribution to climate change by reducing their CO_2 intensity." *Id.* at 44,748. Moreover, EPA appears to have developed its proposed candidate technologies list—which reflects the BSER—with a focus on coal-fired utility boilers without considering whether those heat rate improvement measures would be applicable to gas- or oil-fired utility boilers. For example, intelligent sootblowers are not generally helpful in improving heat rate at oil- or gas-fired utility boilers because those units do not experience particulate matter buildup on heat transfer surfaces to the same extent coal-fired units do. Even for those measures that might be applicable at gas- or oil-fired units, EPA's estimated heat rate improvement potential and cost listed are drawn from the 2009 Sargent & Lundy study, which assessed these values for coal-fired utility boilers only. *Id.* at 44,757, 44,759, Tbls. 1 & 2 (citing Sargent & Lundy). As a result, these estimates have not been validated for oil- or gas-fired units.

Indeed, the Agency has previously recognized that oil- and gas-fired utility boilers generally do not have the same heat rate improvement potential as coal-fired utility boilers and that the same measures may not be adequately demonstrated for utility boilers combusting different fuels. In the proposed and final CPP, EPA determined that it was not appropriate to require that oil- and gas-fired units improve their efficiency as part of Building Block 1. 79 Fed. Reg. at 34,877; GHG Abatement Measures TSD, Appendix at A-2. The Agency observed that gas- and oil-fired utility boilers make up only a small portion of overall CO_2 emissions and already emit CO_2 at significantly lower rates than coal-fired units. GHG Abatement Measures TSD, Appendix at A-2. And it concluded that "oil/gas steam EGUs employ less extensive systems and equipment compared to coal steam EGUs and therefore, in general, have a lesser range of opportunities for implementing [heat rate improvements]." *Id.* at A-3. UARG agrees that the heat rate improvement opportunities that are adequately demonstrated for coal-fired utility boilers are not necessarily adequately demonstrated for utility boilers combusting other fuels.

Because EPA has not proposed to identify the BSER for existing gas- and oil-fired utility boilers, its final action on the Proposed ACE Rule should be limited in scope to existing coal-fired utility boilers. If the Agency wants to address gas- and oil-fired units, it must first issue a proposal identifying an adequately demonstrated BSER, the degree of emission limitation achievable with that BSER, and solicit public comment on that proposal.

C. Heat Rate Improvements Do Not Satisfy the BSER Criteria for Stationary Combustion Turbines. (Comments C-3, C-5, C-10, C-11)

In this Proposal, EPA has not proposed to determine the BSER for stationary combustion turbines and accordingly has not proposed emission guidelines for that source category. 83 Fed. Reg. at 44,761. EPA states that it is aware of various measures that owners and operators can implement at stationary combustion turbines to improve their heat rates, but it lacks sufficient information on the "availability, applicability, or cost of [heat rate improvement] opportunities" for these units, or "the magnitude of expected heat rate reductions," and therefore EPA cannot identify heat rate improvements as the BSER for combustion turbines at this time. *Id.*

UARG agrees that, unlike for coal-fired utility boilers, heat rate improvements are not the BSER for stationary combustion turbines, whether in simple cycle or combined cycle configuration. UARG's consultant evaluated the heat rate improvement projects available for combustion turbines and found that while there may be some opportunities for improved efficiency at individual units, the potential improvements are relatively small, and the examined measures either have limited availability or are unreasonably costly.

This is consistent with EPA's conclusion in the proposed CPP, where the Agency considered whether its proposed Building Block 1 should include efficiency projects at NGCC units. *See* 79 Fed. Reg. at 34,877. EPA determined that the potential heat rate improvements available at combustion turbines are likely to be negligible and not cost-effective. First, while there are some similarities between the steam portion of an NGCC unit and a utility boiler, the heat rate improvement potential for the steam portion of an NGCC unit is "significantly less than in a coal-steam unit because the NGCC steam system is much simpler (gaseous fuel, no back-end scrubbers, less parasitic power, no air heater leakage, no feedwater heaters, etc.) and its flue gas exit temperature is typically already much lower than in a coal-steam unit." GHG Abatement Measures TSD, Appendix at A-4. And second, within the combustion turbine itself, regularly scheduled maintenance practices for components in the hot expansion side of the unit—which are "the most effective [heat rate improvement] methods that can be applied"—are "already being applied across most of the NGCC fleet." *Id.* at A-5. Accordingly, EPA concluded that heat rate improvements were not an appropriate BSER for stationary combustion turbines.

UARG's consultant examined potential heat rate improvement measures that can be implemented at both the combustion turbine and, for NGCC units, the steam cycle. J. Edward Cichanowicz, "Availability and Cost of Heat Rate Improvement (HRI) Actions Applicable to Gas Turbines in the Context of the Affordable Clean Energy Rule" (Oct. 2018) (Attachment D to these comments). For the combustion turbine, the key driver of thermal efficiency is combustor firing temperature, with higher temperatures yielding greater efficiency and lower heat rate. *Id.* at 4. Projects that improve component design and materials can allow older turbines to accommodate higher firing temperatures. To that end, some combustion turbine suppliers offer services to upgrade some or all of a turbine's compressor, combustor, hot gas path, and control system software—known collectively as a "hot gas path upgrade." *Id.* at 5. The costs and efficiency benefits of these projects vary widely but can be meaningful for turbines that can implement a hot gas path upgrade—especially for older turbines that are not equipped with modern component materials.

However, hot gas path upgrades are available only to a small portion of the combustion turbine fleet. Availability of this project depends on the supplier of the combustion turbine. GE offers hot gas path upgrades for its Model 6F, 7FA, 9GFA, 9FB, and 9A turbines but not for its LM series (LMS100, LM6000, LM2500, LM9000), 6b, 7E, 7HA, or 9E turbines. *Id.* at 6-7. Notably, the 7HA and 9E engines already incorporate state-of-the-art features and would not be able to implement further upgrades. *Id.* at 7. Siemens also offers hot gas path upgrade packages for its SGT5-4000F and SGT-800 turbine engines but not for the SGT6-2000E, SGT6-5000F, SGT6-8000H, SGT-800, SGT-750, SGT-700, or Trent 60 turbines. *Id.* Other major turbine suppliers, such as Mitsubishi Heavy Industries, Pratt & Whitney, and Ansaldo-Energia, do not offer hot gas path upgrades for their engines, although they may be developing upgrade packages. *Id.* Because of the limited availability of this heat rate improvement measure for the source category, hot gas path upgrades are not adequately demonstrated and cannot be included in the BSER for combustion turbines.

NGCC units employ a steam cycle to transform the thermal energy from a combustion turbine's flue gas into additional electrical energy. In theory, an NGCC unit could take measures to improve the thermal efficiency of its steam cycle and decrease the overall unit's heat rate. The evaluation by UARG's consultant shows, however, that the opportunities for such improvements are limited and prohibitively costly. One potential measure is the integration of additional steam reheat steps in the steam cycle. *Id.* at 12. But UARG is unaware of any commercial experience with this type of upgrade, and even if technically feasible, it would be available only at turbines that can supply flue gas of sufficiently high temperature to effectively drive further reheat. *Id.* Further, increasing the number of reheat steps would require costly changes within the heat recovery steam generator ("HRSG") to high-pressure steam tubing and to the steam turbine inlet. *Id.*

Finally, a unit owner could consider upgrading the steam turbine blade path, similar to the blade path upgrade for utility boilers included in EPA's candidate technology list for those units. *Id.* at 11-12. Steam turbines designed for application in the steam cycle of an NGCC unit typically differ, however, in design from steam turbines utilized at utility boilers. Due to the need for faster startup times and more frequent load cycling, NGCC steam turbines often require different design features, such as greater clearances between expansion blades, steam leakage seals, and buckets. *Id.* at 11. These differences require some unavoidable steam bypass and loss of energy. *Id.* Although some efficiency gains are theoretically possible through changes to the low-pressure section of an NGCC steam turbine, they would be unreasonably costly and have not been carried out in practice. UARG's consultant estimates these changes could potentially yield a 1.5 percent heat rate improvement at a cost of at least $3.6 million, but this is a rough projection based on experience with coal-fired utility boiler steam turbines, which (as discussed above) are not directly comparable. *Id.* at 13.

In light of the above, heat rate improvement measures do not qualify as the BSER for stationary combustion turbines. Although individual combustion turbines may have some potential to reduce their CO_2 emissions through greater thermal efficiency, the few measures capable of doing so are either not widely available or too costly in light of the minuscule improvements they would offer.

As a side note, UARG observes that EPA's estimate in the Proposal that there is a nationwide "average [heat rate improvement] potential of 3.4 percent" for combustion turbines is fundamentally flawed. 83 Fed. Reg. at 44,761. To develop that average, EPA simply compared each combustion turbine's 2017 heat rate value to its best annual heat rate from 2007 to 2016. *Id.* As

UARG explained in its comments on the proposed NSPS for modified utility boilers, comparing a unit's most recent heat rate or CO_2 emissions data with its "best" year is an inappropriate measure of improvement potential. As with utility boilers, combustion turbines' heat rate values and CO_2 emissions are driven by many factors that are beyond the control of the unit's owner or operator and cannot be intentionally replicated. UARG, Comments on EPA's Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units; Proposed Rule 79 Fed. Reg. 34,960 (June 18, 2014) at 48-49 (Oct. 16, 2014), EPA-HQ-OAR-2013-0603-0215 ("UARG Modified/Reconstructed Comments"). Further, assessing heat rate improvement potential at the national or regional interconnection level is not a valid way to determine what improvements are available for individual units. Indeed, EPA recognized as much in this Proposal, when it explained why the CPP's Building Block 1 analysis was invalid. 83 Fed. Reg. at 44,756.

III. Issues with State Standard-Setting

A. The Diversity of the Existing Utility Boiler Fleet Necessitates the Use of Unit-Specific Standards. (Comment C-14)

In the Proposal, EPA contemplates that states implementing the ACE Rule will develop standards of performance for individual designated facilities by "conduct[ing] unit-specific evaluations of [heat rate improvement] potential, technical feasibility, and applicability for each of the BSER technologies" and accounting for other factors like the unit's remaining useful life. 83 Fed. Reg. at 44,763. In other words, rather than adopting uniform standards of performance that are the same for all units in a source category or subcategory, states will adopt standards of performance that reflect the application of BSER at each individual unit. UARG agrees that this approach is an appropriate way to develop achievable standards of performance in light of the diversity of the existing utility boiler fleet and the variable impact of implementing the BSER at individual units.

As UARG stated in its comments on the ANPR, the fleet of existing EGUs is exceptionally diverse, exhibiting a wide range in age, generating capacity, operating characteristics, fuel type, CO_2

emissions (on both annual and hourly bases), and CO_2 emission rates per unit of output. UARG ANPR Comments at 11-14. To illustrate this diversity, UARG compiled and analyzed data from a subset of 38 existing units (including both utility boilers and NGCC units) from EPA's Clean Air Markets Division ("CAMD") database, the U.S. Energy Information Administration ("EIA"), and other sources, and examined their capacity, CO_2 emissions, operating hours, generation, equipment upgrades, and other characteristics. These data, which were Tables 1 and 2 of the UARG ANPR Comments, are resubmitted with these comments as Attachment E. The selected units represent a broad cross-section of the fossil fuel-fired EGU fleet, reflecting a wide range of sizes, ages, designs, utilization, and locations. The units are located in 14 different states, including locations in the Southeast, Midwest, Northeast, Great Plains, Rocky Mountains, and Southwest. The years in which these units commenced operation range from 1968 to 2012, with the newest coal-fired utility boiler coming online in 2006. The 24 coal-fired utility boilers UARG analyzed include units combusting bituminous, subbituminous, and lignite coals. Based on nameplate capacity, they ranged from 257.0 MW to 1245.6 MW. Units also exhibited a wide range in utilization, from 2,321 hours to 8,784 hours per year (i.e., 100 percent utilization in a leap year).

As one might expect, the units also exhibited significant variation in their CO_2 emissions. Over the period analyzed, annual CO_2 emissions from these coal-fired utility boilers ranged from 1.3 million to 8.2 million short tons per year. Emissions in tons of CO_2 per hour also varied widely: the annual average of hourly CO_2 emissions ranged from 166 to 1,013 short tons per hour. Finally, output-based CO_2 emission rates ranged from 1,676 to 2,418 lbs/MWh-g. In addition to observing significant variability across all units examined, even individual units display significant variation in operations and CO_2 emissions from year to year. Some units exhibit much greater differences between their annual average values, or between the maximum and minimum values within each year, than others. But for all units examined by UARG, the data become less variable when averaged over long periods.

For coal-fired EGUs, output-based CO_2 emission rates (on a lb/MWh basis) are generally lower when the unit operates at higher loads and are generally higher when the unit operates at lower loads. Many coal-fired EGUs have seen declining annual generation over the period from 2007-2016, and some have simultaneously become less efficient. But again, this is not universally true—not all units have seen declining annual generation, and some coal-fired EGUs have maintained fairly consistent efficiency despite declining generation. In addition, although coal-fired EGUs tend to be more efficient at higher loads, their annual CO_2 emissions nonetheless tend to be higher when annual generation increases, as the effect of increased utilization generally outweighs the effect of lower CO_2 emission rates (in lbs/MWh) for individual units.

UARG's analysis found that while various factors (such as coal type, load, and other operating characteristics) can significantly impact a unit's CO_2 emission rate, no single factor or group of factors is overriding, and within any one subset of units, substantial variation remains in CO_2 emissions and emission rates. A unit's CO_2 emissions and emission rate can vary based on many factors, including size, age, operating duty, fuel quality, boiler design, ambient conditions, emission controls, cooling systems, and others—and much of the resulting variation in emission rates is beyond the unit owner or operator's control. Thus, utility boilers' CO_2 emission rates are influenced by too many different factors to allow EPA to define meaningful subcategories for purposes of identifying the BSER or establishing achievable standards of performance.

Likewise, it is not possible to adopt uniform standards of performance based on application of EPA's proposed BSER for existing utility boilers because the impact of implementing heat rate improvements—and the resulting effect on a unit's CO_2 emission rate—will vary significantly at each unit. Heat rate improvement measures are not like add-on emission controls for other pollutants; many of which can be designed for a desired percent removal from the unit's flue gas stream. Instead, the improved efficiency resulting from implementation of any specific measure will vary based on the design and condition of the individual unit, as well as the effects of other heat rate improvements carried out at the same time and any changes in the unit's operations that might counteract any efficiency gains. In the Proposal, EPA itself recognizes that the potential improvements available through BSER implementation "may vary considerably at the unit level." 83 Fed. Reg. at 44,755. EPA also recognizes that some owners or operators will have already deployed some or all of the listed candidate technologies at the time of state plan development, and that even where available and appropriate for use in standard-setting, the potential improvement available from any of these technologies can vary widely. *See id.* at 44,757 & Tbl. 1.

Likewise, UARG explained in its comments on the proposed CPP that the efficiency benefits associated with heat rate improvements are highly variable by unit, are not cumulative, and degrade over time. UARG CPP Comments at 212-214. A report by the National Coal Council, a federal advisory committee to the U.S. Secretary of Energy, highlighted that "[t]he opportunity to apply these efficiency improvements across the existing fleet will vary significantly." National Coal Council, "Reliable & Resilient – The Value of Our Existing Fleet: An Assessment of Measures to Improve Reliability & Efficiency While Reducing Emissions" at 4 (May 2014) ("NCC Report"), http://www.nationalcoalcouncil.org/reports/1407/NCCValueExistingCoalFleet.pdf. Measures that may improve heat rate at an individual plant by as much as 1 percent may yield only negligible or nonexistent benefits at many others that have already implemented similar measures or that are otherwise operating in a highly efficient manner. *Id.* For example, large benefits from steam turbine upgrades (the highest-payoff measure) are possible only for units that are already severely degraded; for most units, the available payoffs would lie at the low end of the possible range. *Id.* at 62.

Further, many of the available actions to improve heat rate do not provide cumulative benefits and thus cannot simply be added together to estimate the potential efficiency gains at coal-fired EGUs. Their impact on the unit's overall heat rate will depend on what other heat rate improvements, if any, are being implemented. For example, measures that increase heat removal from the boiler, such as economizer modifications and improved air heater performance, do not provide additive efficiency benefits because any heat that is recovered by an individual project cannot be recovered a second time. UARG CPP Comments at 213-14; NCC Report at 69.

Finally, to the extent that any measures to improve heat rate are available at a given unit, the long-term payoffs of many of these measures are significantly smaller than the immediate reduction in heat rate observed after implementation. UARG CPP Comments at 213. Upgraded components begin to incur wear as soon as they return to operation and will need to be replaced themselves eventually in order to maintain the improved heat rate. For example, while a steam turbine upgrade may improve a unit's heat rate below its design level, gradual degradation of the turbine blades will reduce the magnitude of that improvement over time from the "new" state without periodic overhauls. Field data indicate that the efficiency of a steam turbine retrofit may decline by 0.5 percentage points in the first 6 months, and by about 4 percentage points after 10 years. Accordingly, standard-setting cannot be based on the immediate, short-term payoff expected from efficiency improvement measures but must account for how that payoff will degrade over time, including consideration of the unit's planned maintenance cycle.

Thus, in light of the extreme heterogeneity of the existing utility boiler fleet and the variable effect of heat rate improvements on these units' CO_2 emission rates, a source-by-source standard-setting methodology is the most reasonable way for states to develop achievable standards of performance for designated facilities covered by their state plans.

B. EPA Should Further Identify the Elements of a Satisfactory State Plan.

1. Providing Minimum Criteria for a Satisfactory Plan Is Consistent With EPA's Statutory Authority.

The Proposal properly recognizes the primary role of states in establishing achievable standards of performance for existing sources within their boundaries, including states' discretion to vary the requirements for individual sources based on remaining useful life and other factors. Consistent with EPA's role under the statute, the Proposed ACE Rule (1) defines emission guidelines that identify the BSER for categories of designated facilities and provide information on the degree of emission limitation achievable through application of the BSER, and (2) requires that EPA determine whether state plan submissions satisfy the guidelines.

UARG believes that consistent with EPA's statutory role, implementation of the Proposed ACE Rule would be aided by further direction from EPA to states as to what the Agency would (or would not) consider to be necessary for a "satisfactory" state plan. The Proposal's regulatory language on required state plan elements provides a useful general framework for state plan development, but it should be supplemented in specific ways. *See* 83 Fed. Reg. at 44,808-09, Proposed 40 C.F.R. §§ 60.5735a-60.5755a. For example, the emission guidelines should confirm and clarify that a state's plan should be approved provided the record shows that the state considered and addressed certain relevant factors in developing unit-specific standards.

2. EPA Should Provide Expanded Guidance on Identifying "Applicable" Heat Rate Improvement Measures. (Comment C-23)

EPA should provide additional clarification on how its emission guidelines anticipate states are to determine which candidate technologies are appropriate for states to apply to individual utility boilers for standard-setting purposes and how states should determine the impact implementation of those technologies would have on the unit's CO_2 emission rate. That guidance should make clear that a measure should not be considered "applicable" and able to yield additional heat rate benefits if the unit has already applied it. States should be directed to consider the costs and benefits of implementing each technology at a unit when determining whether it is "applicable" and eliminate any measures that are unreasonably costly or not cost-effective. At existing units, economic feasibility is a key component of ensuring that the BSER has been adequately demonstrated and the standard of performance is achievable. Measures that are unreasonably costly or that have an unreasonable payback period cannot be part of the BSER as it is applied to an individual utility boiler.

The guidelines should also make clear that, in determining how much any "applicable" candidate technologies will impact a unit's heat rate, the state must conduct a unit-specific evaluation of the degree to which each candidate technology can actually improve heat rate at the unit, the cost of implementing that measure, and the expected payback period, based on the unit's design, operational history, expected future operations, current state of repair, and other relevant factors. As discussed in Section III.A above, the impact of any particular heat rate improvement measure will vary from unit-to-unit, and these impacts are often not additive and will degrade over time. Thus, it is essential that states engage in source-specific analyses rather than resorting to default assumptions. As EPA recognizes in the Proposed ACE Rule, states "will be expected to conduct unit-specific evaluations of [heat rate improvement] potential, technical feasibility, and applicability for each of the BSER candidate technologies." *Id.* at 44,763. Thus, this seems to be the intended meaning of EPA's proposed regulations. EPA should emphasize and clarify in the final rule language that this unit-specific analysis is an essential part of the standard-setting analysis for any satisfactory state plan.

Finally, the guidelines should recognize and affirm that the analysis discussed above regarding what heat rate improvements are applicable to an individual unit need not be performed by the state in the first instance. Instead, a state plan will also be satisfactory if the state allows source owners to self-audit or retain third-party consultants to evaluate their units' heat rate improvement potential and submit those results to the state for review and use in standard-setting. A similar approach is often used in PSD permit proceedings, where the permit applicant includes a proposed BACT determination with its application that the permit issuer then reviews and either adopts as its own proposed BACT determination in a draft permit or alters based on any disagreement with the applicant's analysis. Allowing the owner or operator of an existing utility boiler to submit proposed determinations of "applicable" heat rate improvements would reduce the administrative burden on states implementing the ACE Rule and would be a more efficient way to conduct these analyses given that the unit owner or operator is most familiar with the unit's characteristics and has easy access to the necessary data.

3. States Must Demonstrate That They Have Considered Specific Factors Affecting Their Standards' Achievability. (Comments C-22, C-23, C-24)

The guidelines should identify specific factors that affect whether the plan's standards of performance are achievable—specifically, heat rate degradation, representative baseline conditions, future operating conditions, and variability of continuous emissions monitoring systems ("CEMS")—and should make clear that state plan submissions must explain how these factors have been accounted for in establishing a unit-specific standard. EPA's implementing regulations for section 111(d), as the Agency has proposed to amend them, require the Agency's emission guidelines to include "[i]nformation on the degree of emission reduction which is *achievable* with [the BSER], together with information on the costs, nonair quality health [and] environmental effects, and energy requirements of applying each system to designated facilities." *Id.* at 44,804, Proposed 40 C.F.R. § 60.22a(b)(2) (emphasis added); *accord* 40 C.F.R. § 60.22(b)(3) (current language). Under settled case law, in order to be "achievable," a standard of performance under section 111 must be capable of being met "under the range of relevant conditions which may affect the emissions to be regulated," including "under most adverse conditions which can reasonably be expected to recur."

Nat'l Lime Ass'n, 627 F.2d at 431 n.46, 433. The agency establishing the standard "must (1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the test data relied on by the agency are representative … given the range of variables that affect the achievability of the standard." *Sierra Club*, 657 F.2d at 377 (citing *Nat'l Lime Ass'n*, 627 F.2d at 433). In other words, section 111 standards of performance must be achievable by the unit over the long term, including under a wide range of realistic operating conditions, and must be based on an analysis of representative data that accounts for those operating conditions. Thus, in order to fulfill its obligation to provide "[i]nformation on the degree of emission reduction which is achievable" through application of the BSER, EPA's emission guidelines must identify the factors that affect achievability and require states to provide reasonable compliance margins to account for them.

Specifically, states must account for the fact that a unit's heat rate naturally degrades over time. As discussed in Section III.A above, as an EGU's components wear, its efficiency will gradually decline, and regular maintenance and repairs to the unit can only partially reclaim that lost efficiency. Even for the candidate technologies included on EPA's list, the initial heat rate improvement obtained by implementing those measures will degrade over time. Accordingly, states should set each unit's standard of performance at a level that reflects what its heat rate will degrade to over the course of its maintenance cycle, rather than what its heat rate will be immediately after implementing any applicable measures from the list of candidate technologies.

Second, states must consider whether they are establishing standards of performance based on representative baseline conditions for the unit. In response to the natural degradation discussed above, unit owners routinely take steps to maintain their heat rates and may do so on a regular maintenance cycle. Thus, a unit's heat rate shortly after a maintenance outage may not represent how the unit will perform in a few years near the end of its maintenance cycle. Therefore, states should not simply set standards of performance based on assumed reductions from the unit's heat rate at the time standard-setting is conducted: they should consider whether an earlier baseline period is more representative of the unit's future performance.

Third, the state should account for any anticipated changes in how a unit may be deployed in the future. Operating load is one of the most significant factors influencing an EGU's CO_2 emission rate, and a shift to more operation at low loads or greater cycling can substantially increase a unit's average CO_2 emissions per unit of output. *See* UARG ANPR Comments at 38-39. If a unit is expected to operate differently in the future, the state should consider how that different operating profile will affect the unit's CO_2 emissions and demonstrate that its standard of performance will not prevent the unit from operating as needed.

Finally, EPA should make clear the Proposed ACE Rule's intent that in setting standards and establishing procedures for determining compliance with standards, states must take into account the potential variability and associated uncertainty in applicable measurements.[7] As UARG explained in comments on the CPP and the ANPR,[8] all measurements are subject to some level of variability, and therefore uncertainty, and the monitoring conducted by EGUs is no exception. Even with application of stringent quality assurance and quality control requirements for CEMS under 40 C.F.R. part 75 ("Part 75"), there are many potential sources of variability in EGUs' CO_2 and heat rate measurements that are unrelated to actual changes in emissions or efficiency. Significant variations over time can result from normal activities like changes in monitoring system calibrations, reference methods, stack diameter measurements, monitoring technology, and flue gas handling systems. *See* Memorandum from Ralph L. Roberson, P.E., RMB Consulting & Research, Inc., to UARG Measurement Techniques Committee, "Real Heat Rate Improvement or Measurement

[7] Although the Proposal requires states to promulgate standards of performance that are "quantifiable" and "verifiable," 83 Fed. Reg. at 44,809, Proposed 40 C.F.R. §§ 60.5740a(a)(3), 60.5755a(b), EPA's proposed definitions of those terms do not appear to encompass the impact of measurement variability on compliance, *see id.*, Proposed 40 C.F.R. § 60.5755a(c), (d).

[8] UARG CPP Comments at 224-28; UARG ANPR Comments at 34, 48-50.

Variability/Uncertainty" at 3-8 (Nov. 25, 2014) ("Roberson Report") (Attachment F to these comments).

Although the effects of this measurement variability are not so prevalent or severe as to undermine confidence in the Part 75 data as a whole, the effects are real. For example, in cases where relatively small improvements (or no improvements) in efficiency are mandated, normal measurement variability could easily cause exceedance of a performance standard that was based on expectations of a small emission reduction from a baseline (or based on "business as usual"[9] operation) but that did not take the potential for measurement variability into account. Just as EPA does when it establishes NSPS for categories of sources, either states must ensure that the data they use to set and enforce these unit-specific efficiency standards are sufficient to account for the potential measurement variability (e.g., by averaging data over multiple years), or they must provide some other mechanism by which EGUs can compensate for these effects. Unlike performance standards based on application of emission control technology, standards for energy efficiency cannot be met by increasing use of controls. While UARG reads the Proposed ACE Rule to already require states to account for this issue, EPA should make clear in the final rule that states have sufficient flexibility in setting performance standards to take into account the potential impacts of measurement variability on compliance.

4. Standards for Existing Units Should Not Be More Stringent Than NSPS.

EPA should also confirm in its final rule that state standards of performance for existing units may not be more stringent than the corresponding NSPS that would apply if the EGU were new, modified, or reconstructed. Given the economic, physical, and technological constraints on retrofitting existing units, the application of BSER for existing plants cannot result in more stringent

[9] EPA uses this term to describe a performance standard a state might set for an EGU that already has implemented all of the candidate technologies. 83 Fed. Reg. at 44,766.

regulation than new plants. As EPA recognized when it first published its section 111(d) implementing regulations in 1975, "the degree of control [for existing sources] … will ordinarily be less stringent than … required by standards of performance for new sources" based on the fact that "controls cannot be included in the design of an existing facility … and physical limitations may make installation of particular control systems [at an existing facility] impossible or unreasonably expensive in some cases." 40 Fed. Reg. at 53,341, 53,344. Reflecting that reality, until the CPP, EPA had never before adopted new source standards that were less stringent than the standards its existing source guidelines required states to adopt. EPA should recognize in the final rule that the NSPS that would apply to a designated facility if it were new, modified, or reconstructed is the floor for that unit's standard of performance.

5. State Standards of Performance Do Not Need to Be "Non-Duplicative."

In the Proposal, EPA claims that it has "historically and consistently required that obligations placed on sources be quantifiable, non-duplicative, permanent, verifiable, and enforceable," and that it is therefore proposing that standards of performance in state plans meet those same criteria. 83 Fed. Reg. at 44,765. Accordingly, the proposed regulatory language states that standards of performance in state plans "must be demonstrated to be quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected EGU," and defines how each of those criteria (except for "non-duplicative") may be demonstrated. *Id.* at 44,809, Proposed 40 C.F.R. § 60.5755a(b).

UARG is not aware, however, of any historical practice by EPA of requiring that a section 111 standard of performance obtain "non-duplicative" emission reductions from an affected source. To the contrary, the list of required elements for a standard of performance appears to have been imported into the Proposed ACE Rule from the CPP, where these concepts were used to ensure that sources' use of emission credits for compliance resulted in real emission reductions. *See* 80 Fed.

Reg. at 64,850 (providing example of a "duplicative" emission standard where "a quantified and verified MWh from a wind turbine could be applied in more than one state's CAA section 111(d) plan to adjust the reported CO_2 emission rate of an affected EGU (*e.g.*, through issuance and use of an [emission rate credit])"). The "non-duplicative" requirement makes no sense for a standard of performance that is based on an individual unit's emission rate, because section 111 is unconcerned with whether a unit reduces its emissions incrementally from what would be required under other rules provided the unit emits at a level that represents application of the BSER. Accordingly, EPA should simply delete the requirement for "non-duplicative" standards from Proposed 40 C.F.R. § 60.5755a.

C. Compliance Deadlines Should Be Dated from Plan Approval, Not Plan Submittal. (Comment C-13)

EPA proposes to leave states the discretion to set compliance periods for the standards of performance applicable to individual designated facilities in the state, provided that any compliance period extending more than 24 months from the date required for plan submittal includes legally enforceable increments of progress. 83 Fed. Reg. at 44,809, Proposed 40 C.F.R. § 60.5750a. UARG supports leaving decisions about the appropriate compliance period for each unit's standard to the states but suggests some changes to EPA's proposed requirements for legally enforceable increments of progress.

The authority to adopt different compliance deadlines for different units is inherent in states' authority to consider remaining useful life, cost, feasibility, and other factors in applying standards to individual designated facilities. CAA § 111(d)(1). Exercise of that authority is particularly appropriate in this program because some units may become subject to performance standards that are based on implementation of several specific heat rate improvement measures, while others become subject only to "business as usual" standards because no additional heat rate improvements are appropriate.[10] A unit that is expected to take several measures to substantially improve its heat rate will need more time before its compliance period begins than will a unit with a "business as usual" standard.

In setting compliance periods and schedules, each unit's planned outage schedule must be considered. Existing EGUs typically undertake projects to improve or maintain their efficiency on regular multi-year maintenance schedules, and having implementation of state plan requirements coincide with a unit's already-planned outages will reduce the overall cost of EPA's proposed rule without compromising environmental goals.

As discussed below in Sections XIII-XVII, UARG generally supports EPA's proposed revisions to the new source review ("NSR") program. In the event that any of the heat rate improvement projects undertaken to comply with this rule do require NSR permitting, however, the final rule should provide that any compliance deadlines are tolled for the time it takes to complete the NSR permitting process to authorize the commencement of the project.

UARG recommends that the proposed rule language on establishing legally enforceable increments of progress not be tied to the date for state plan *submittal* but instead to the date of state plan *approval*. *See* 83 Fed. Reg. at 44,805 & 44,809, Proposed 40 C.F.R. §§ 60.24a(d)(1), 60.5750a. This change will assure that designated facilities will not be required to make investments to comply with standards of performance that EPA disapproves, avoiding significant disruption and potentially stranded investments in cases where EPA ultimately disapproves the state's plan and requires different compliance measures. While the proposed Subpart Ba implementing regulations require EPA to approve or disapprove a state plan "within twelve months of finding that a plan or plan revision is complete," which is less than 24 months, *id.* at 44,806, Proposed 40 C.F.R. § 60.27a(b),

[10] As part of a state's consideration of cost and of a unit's "remaining useful life," EPA should make clear that states should take a "business as usual" approach for units that have announced their retirement or make clear that states could exempt these units from the program.

history shows that EPA may not be able to take final action on every state plan submittal within that time frame. And the deadline for EPA action on state plan submittals does not begin to run until EPA makes a completeness determination, which itself is not required until months after the deadline for state plan submittals (and which EPA might also be unable to complete on time). *See id.* at 44,806-07, Proposed 40 C.F.R. § 60.27a(g)(1). Significant lead time is needed to plan for and carry out the necessary steps to show progress towards implementing standards of performance without disrupting electric reliability, and the time provided by the Proposed ACE Rule may be insufficient even if EPA meets its deadlines for plan review and approval or disapproval.

To ensure that designated facilities are not required to invest in complying with a state plan that is ultimately not approved, the requirement for enforceable increments of progress should be tied to state plan approval. In light of the lead time required to make the necessary changes at electric utility sources, to account for outage schedules at units, and to ensure the availability of contract workers, EPA should also extend the time period during which enforceable increments of progress are not required from 24 to 36 months for purposes of the ACE Rule.[11] Finally, UARG notes that some states may wish to submit plans well in advance of the regulatory deadline. To avoid penalizing designated facilities in those states, EPA should provide that enforceable increments of progress will by no means be required for standards that take effect within 36 months of the deadline for state plan submittal. To give effect to these changes, UARG suggests the following amendments to the proposed regulatory language, shown in underline:

> 40 C.F.R. § 60.24a(d)(1): <u>Unless otherwise specified in the applicable emission guideline, a</u>ny compliance schedule extending more than 24 months from the date required for submittal of the plan must include legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities.
>
> *   *   *

[11] UARG takes no position on whether the period should be extended to 36 months for Subpart Ba generally.

40 C.F.R. § 60.5750a: … The standards of performance for affected EGUs regulated under the plan must include compliance periods. Any compliance period extending more than ~~24~~36 months from the date required for submittal of the plan or the date of plan approval, whichever is later, must include legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities.

D. EPA Should Allow States' Standards of Performance to Take Many Forms. (Comment C-15)

EPA proposes to require that states "set a standard of performance for each affected EGU within the state" that is expressed as "an emission performance rate relating mass of CO_2 emitted per unit of energy (*e.g.* pounds of CO_2 emitted per MWh)." 83 Fed. Reg. at 44,809, Proposed 40 C.F.R. § 60.5755a(a). In the preamble, EPA justifies its focus on this particular form of standard of performance by arguing that it "most closely aligns to EPA's BSER determination"; that it is "the most straightforward system for states to determine standards and ensure compliance"; and that it "creates a more streamlined evaluation for EPA to consider in state plan evaluation as there are fewer variables to consider." *Id.* at 44,764-65.

UARG does not agree that standards of performance in state plans should be limited to standards expressed as lb CO_2/MWh. Instead, states should have the authority and discretion to select alternative forms for their standards of performance. Section 111(d) leaves states broad discretion to develop standards of performance for existing units and to provide for their implementation. To the extent that a state wishes to adopt standards of performance that take a different form in its state plan, the state should have the opportunity to demonstrate to the Agency that the alternative form can be shown to reflect the "degree of emission limitation achievable through the application of the [BSER]." CAA § 111(a)(1).

A state plan should be satisfactory if it contains an emission rate for each affected facility (or rates, in the case of a facility for which the state establishes different rates for different loads[12]) that

[12] EPA should not limit states to adopting one standard of performance for each EGU that covers all periods of operation. Because a unit's heat rate and CO_2 emission rate can vary

reflect the degree of emission limitation achievable through application of BSER, after consideration of remaining useful life and other source-specific factors. The unit-specific emission rate will define the level of improved performance that satisfies the 'performance standard' requirement of section 111(d).

Once established, there may be alternative ways to demonstrate that the affected facility has achieved the level of improved performance required by EPA's guidelines. For example, if requested by the source, a state might translate the affected facility's emission rate into a mass-based standard (e.g., tons per hour or tons per year) that ensures compliance with its improved performance obligation. Under such a plan, an affected facility could comply by demonstrating that it has achieved its improved performance obligation using either its emission rate(s) or mass-based standard. A plan that contains alternative mass-based standards will be deemed satisfactory if the state demonstrates that the alternative standards will not cause mass emissions to exceed what they would have been under the emission rate(s) applicable to the affected facility.

Allowing units to comply with standards of performance in this form could help states address the paradoxical fact that for coal-fired utility boilers generally, the unit's CO_2 emission rate (in lb CO_2/MWh) is *higher* when its operating load (and mass of CO_2 emitted) is *lower*. So long as each standard of performance reflects application of the BSER to the unit, any such approach should be satisfactory for EPA.

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significantly by operating load, a state may wish to adopt multiple standards for each unit that apply to different load ranges. The unit might be subject to one standard for full load operations, another for operations at 70-90 percent of its generating capacity, and so on. This approach might help with compliance for units that have an uncertain operating future. Rather than being bound to a single standard of performance that reflects certain baked-in assumptions regarding future operating loads, the unit's compliance obligation would vary based on actual utilization.

E. EPA Should Limit Output-Based Standards to Gross, Not Net, Output. (Comment C-16)

Where a state does opt to express its standards of performance in terms of CO_2 emitted per unit of output, however, EPA should require that the standard be based on gross output rather than net output. Unlike the alternative standard of performance forms discussed above, use of net output-based standards would undermine implementation of the BSER by introducing new implementation and compliance costs. A net output-based standard would be unworkable, unnecessary, and would require implementation of costly new monitoring measures, whereas gross output is straightforward, simple, consistent, directly measured, and already reported to EPA for other purposes as required by Part 75.

For a host of reasons, it would be impractical, costly, and inefficient for states to require compliance with net output-based standards. EGU owners and operators have already installed the necessary equipment to monitor and report hourly gross output at individual affected EGUs with the level of accuracy and granularity required by Part 75 and have been submitting this information to CAMD for years. This database of historical hourly emissions and gross generation information provides a readily available source of information for states to use in establishing standards of performance that are achievable for the individual units they apply to. Conversely, EGUs do not currently monitor and report net output data to EPA on a unit-by-unit basis or as granular as the hourly Part 75 data, and those data are not available to unit operators on a real-time basis for continuously ensuring compliance. Some net output data are available through the EIA, but those data may be difficult to attribute to specific affected sources and are not available for all years. Therefore, no useful historical data on net output are readily available for states to use in standard-setting.

Going forward, in order to comply with a net output-based standard EGU owners and operators would need to develop additional monitoring of parasitic load within the plant and, in many cases, determine how to allocate that parasitic load among affected EGUs at the facility to determine each individual unit's net output. They would also need to make that information available to operators on a real-time basis so they can take actions to affect units' net output-based emission rate. The cost of these new monitoring and operational systems would need to be factored into the cost of EPA's emission guideline rulemaking.

Parasitic load cannot be easily allocated to individual units at a plant. Some station services that require power may be powered by (and serve) multiple EGUs rather than individual ones—for example, a scrubber may handle flue gas from multiple EGUs or may utilize materials handling systems (such as limestone and slurry processing) common to all units. Other station services may not have a clear connection to any one EGU, such as lighting for the facility. At some facilities, auxiliary electric power services may be drawn from the grid rather than on-site. Even where auxiliary load is clearly supplied by a single identifiable unit at a multi-unit plant, net output-based standards can provide a distorted view of an EGU's efficiency. A station service that serves multiple EGUs, such as coal handling equipment, may be powered by a single EGU's gross generation. That EGU may unfairly appear less efficient than other EGUs at the facility. Further, differences in how various plants account for these parasitic loads and allocate them to individual EGUs may lead to source-by-source variation and inconsistency in reported CO_2 rates and compliance.

Other practical concerns for compliance with net output-based standards exist as well. Parasitic loads may not be constant for all operating loads or ambient conditions. For example, parasitic load may have a greater impact on a unit's CO_2 emission rate in terms of net output at low loads than high loads. Thus, the need to spend more time operating at low load—which is beyond the unit owner's control—may make it more difficult to comply with a net output-based standard. And during some periods of operation, net output may actually be negative, which could unfairly drive down the denominator of a unit's compliance calculation.

These concerns are all the more significant in light of the fact that there are no clearly identifiable benefits to basing standards of performance on net rather than gross output. The most commonly cited motivation for encouraging use of net output-based standards is to promote more efficient generation of electricity. But EGU owners and operators already have more than adequate incentives to operate as efficiently as possible within the constraints of their emission control requirements. Many electric generators operate in competitive markets subject to security constrained economic dispatch, in which the least cost units are generally dispatched first. Likewise, electric cooperatives maximize efficiency because any cost savings are passed on directly to members. Fuel is the largest operational cost in producing electricity. Thus, the best way for a source owner or operator to reduce its cost of generating electricity is to maximize the amount of electricity supplied to the grid (rather than to on-site activities) per unit of fuel. Requiring compliance with a net output-based standard does not provide a meaningful additional incentive.

In fact, the use of net output-based standards could have at least one negative side effect: it penalizes EGUs for installing and operating emission control technology. Emission controls, such as scrubbers, SCR, and fabric filters, can impose substantial parasitic load requirements on EGU facilities. A unit that installs such controls will see a significant decrease in its net output—which would increase its CO_2 emission rate in terms of lb/MWh-net. Likewise, use of net output-based standards would also eliminate incentives for EGUs to operate their emission controls beyond the bare minimum necessary to comply with other emission limits. Because over-control of pollutants may increase the parasitic load needed to power the control system, an EGU owner may be forced to increase its emissions of other pollutants in order to meet a net output-based CO_2 limit.

For all these reasons, UARG urges EPA to state that net output-based standards are not an acceptable element of satisfactory state plans under the ACE Rule. Further, if EPA decides to allow the use of net output-based standards, then it must at least provide that units can demonstrate compliance with those standards by averaging with other affected EGUs at the same plant, in order to alleviate the problems associated with allocating parasitic load at a plant to individual EGUs.

IV. State Authority to Provide for Flexible Options to Demonstrate Compliance with Standards of Performance (Comments C-17, C-28, C-29, C-30, C-31, C-32, C-33, C-34, C-38, C-40, C-41)

Any final emission guideline should recognize and define the scope of states' authority to provide flexible compliance options that affected EGUs may use to address performance variability that is inherent in EPA's BSER between units and over time, and to achieve more cost-effectively collective BSER emission levels. As EPA has recognized in promoting flexible compliance under CAA regulatory programs, including section 111(d), flexibility allows sources to achieve the CAA's environmental goals while minimizing cost. *See Michigan v. EPA*, 135 S. Ct. 2699 (2015) (recognizing importance of considering cost in agency rulemaking). It also provides incentives for sources to pursue additional emission reductions beyond those required by a rule.

In the Proposed ACE Rule, EPA has recognized these principles and has proposed to allow states to include some forms of flexible compliance in their state plans. Specifically, the Proposal would allow states to incorporate emissions averaging among EGUs across a single facility. 83 Fed. Reg. at 44,767. UARG agrees that states should be allowed to incorporate these options into their state plans. Averaging within a facility particularly makes sense given that some of the candidate technologies EPA has identified as part of the BSER, such as VFDs, may affect multiple units at a power plant.

Averaging should not be limited, however, to a single plant site. Although standards of performance must be based on application of the BSER that can be applied at an individual source, the CAA allows states flexibility in *implementing* those standards consistent with the objectives of the program at issue. Depending on the program, that flexibility should include averaging among affected EGUs within a plant, averaging among affiliated affected EGUs within a state, or even averaging with unaffiliated affected EGUs within the state.

In the case of section 111(d), EPA has suggested that allowing averaging beyond a plant may lead to sources in the affected source category complying by shifting generation away from the affected facility to others that are outside the Proposed ACE Rule program, rather than improving the performance of that affected facility. *Id.* at 44,768. By restricting averaging to affected EGUs subject to unit-specific performance standards (i.e., coal-fired utility boilers subject to the ACE Rule), State plans cannot authorize the transfer of compliance obligations to sources in other source categories, thereby minimizing the possibility that affected facilities can engage in generation shifting to avoid their section 111(d) "improved performance" obligation. Instead, affected EGUs in the averaging program must collectively achieve the level of performance required by the BSER for each unit. The principal impact of averaging will be to ensure that the variable and uncertain impacts of the heat rate improvements over time can be accounted for by allowing individual affected facilities that are implementing heat rate improvements to address the consequences of emission excursions that will almost invariably happen over time.

EPA also expresses concern that averaging across affected sources "would be inconsistent with our proposed interpretation of the BSER as limited to measures that apply at and to an individual source," and that "implementation and enforcement of [standards of performance] should correspond with the approach used to set the standard in the first place." *Id.* at 44,767. Nothing in the CAA precludes implementation of performance standards so as to produce collective emission reductions that comply with BSER levels of reduction. For example, in 1987, EPA issued a final rule allowing two coal-fired utility boilers to average their emissions to comply with the applicable NSPS for SO_2. 52 Fed. Reg. 28,946 (Aug. 4, 1987). In establishing this "compliance bubble," EPA made clear it was "not establishing a new NSPS," but "[r]ather, the bubble merely amends Subpart D to allow [the owner and operator of the EGUs] to demonstrate compliance with the existing NSPS in a different manner." *Id.* at 28,949. In response to comments arguing that section 111(e) precluded the bubble, EPA stated that "[s]ince section 111(e) does not specify how compliance with an NSPS is to be determined for any source, EPA has discretion to establish the appropriate method of compliance." *Id.* at 28,950. The same is true for section 111(d) and the states.

Moreover, nothing in section 111(d) precludes state use of flexible compliance mechanisms, as long as the state plan ensures that the improved performance objectives of the program are met. To the contrary, section 111(d) establishes a clear bifurcation between standard setting and standard implementation. It contains separate and distinct requirements for states to "(A) *establish*[] standards of performance for any existing source … and (B) provide[] for the *implementation and enforcement* of such standards of performance." CAA § 111(d)(1) (emphases added). Where averaging and trading among affected EGUs within a state is structured so as to ensure that affected facilities achieve their improved performance objectives, use of these techniques is no different than allowing an affected EGU to comply with a standard of performance using emission reduction systems that do not represent BSER. For example, although EPA cannot require a state to force a source to use CCS to meet a standard of performance based on heat rate improvement technologies, the source may elect to use CCS to meet that standard of performance. *See* 52 Fed. Reg. at 28,951 ("The NSPS is by definition a standard of performance. The performance that is required is to achieve an SO_2 emission limit of 1.2 lb/MMBtu. The NSPS does not dictate what technique(s) a source must use to meet the emission limit."). Moreover, allowing an EGU to meet an emission limit based on averaging its performance with other EGUs is an implementation method that assures compliance with BSER levels of control.

The concern that use of an averaging or trading program "might undermine EPA's BSER, which EPA is proposing to determine as a menu of heat rate improvements," 83 Fed. Reg. at

44,768, can be addressed for the same reasons discussed above. Under section 111, each affected facility's obligation is to comply with a standard of performance based on what is achievable with the BSER. Averaging in the appropriate case can allow an affected facility to comply with its BSER improved performance obligation, and for the source category collectively to achieve more cost-effectively BSER levels of emission reduction, while addressing issues associated with the uncertainty and variability inherent in the BSER. *See* CAA § 111(b)(5).

Allowing for flexible compliance through emissions averaging between affected EGUs of the same type would not render section 111(d)'s provisions regarding remaining useful life "superfluous." 83 Fed. Reg. at 44,767. Again, the CAA establishes a clear distinction between the standard-setting phase (in which states must be allowed to consider remaining useful life to establish performance standards for individual units) and the standard implementation phase. Providing states with a *voluntary option* for averaging and trading between same type affected sources to implement the standard does not excuse the state from considering remaining useful life in setting a unit's standard of performance, since the unit needs to be able to achieve the standard even if such averaging or trading is not available. Moreover, flexible compliance is not simply a tool to make it easier for sources nearing their retirement date to comply with standards—it can also be used as a tool to *encourage* these or other sources to pursue additional emission reductions that EPA or the state could not require in setting the standard.

Section 110, which the CAA points to as a model for how section 111(d) should be implemented, provides an informative example. Section 110(c) gives states broad flexibility regarding how to implement the NAAQS, including authority to implement emission limitations through "economic incentives such as fees, marketable permits, and auctions of emissions rights." CAA § 110(a)(2)(A). This is true even though states already have authority to vary the requirements applicable to different sources as they see fit, including by adopting less stringent standards for sources with a shorter remaining useful life.

Consistent with this authority, EPA has previously provided for broad compliance flexibility options in other rulemakings under section 111(d). In addition to allowing averaging within facilities, EPA's emission guidelines for large municipal waste combustors, promulgated jointly under sections 111(d) and 129, allow states to "establish a program to allow owners or operators of municipal waste combustor plants to engage in trading of [NOx] emission credits." 40 C.F.R. § 60.33b(d)(2). In the Clean Air Mercury Rule ("CAMR"), 70 Fed. Reg. 28,606 (May 18, 2005), EPA identified the BSER as emission control measures that could reduce mercury emissions at the individual affected source but provided an avenue for compliance through a broad system of mercury emissions trading.

Accordingly, EPA should not foreclose states from including broader compliance options than facility-specific averaging in their state plans. Indeed, EPA *must* approve a state plan so long as it is "satisfactory." In the context of section 110, states have broad discretion in developing state implementation plans ("SIPs") to implement the NAAQS, and EPA cannot disapprove a SIP based on its disagreement with the state's policy choices so long as it meets the minimum statutory requirements. *See Union Electric Co. v. EPA*, 515 F.2d 206 (8th Cir. 1975). State discretion is at least as broad in the context of section 111(d), as EPA has repeatedly emphasized in the Proposed ACE Rule. *See* 83 Fed. Reg. at 44,748, 44,749, 44,750, 44,765 (discussing state role in 111(d) process).

EPA should also allow states to reward early action and to provide source owners credit for when a source shuts down, as has been done in other section 110 implementation rules.

V. Proposed Monitoring, Reporting, and Recordkeeping Provisions

A. EPA Appropriately Authorizes Use of Part 75 Data, But Some Clarifications Are Needed.

EPA appropriately recognizes that because EGUs already are monitoring and reporting most, or all, of the information necessary to demonstrate compliance with a standard of performance based on the proposed emission guidelines,[13] states should be allowed to rely exclusively on those data to enforce their performance standards. 83 Fed. Reg. at 44,769. This determination is reflected in Proposed § 60.5785a(a)(1), which UARG supports. *Id.* at 44,810. Consistent with Proposed § 60.20a(a)(1) and Proposed § 60.5700a, however, EPA should make clear that this provision completely supersedes the requirements in Proposed § 60.24a(b)(1) for use of test methods in Appendix A to Part 60[14] to determine compliance. *Id.* at 44,803, 44,808, 44,805. As proposed, § 60.5785a(a)(1) merely authorizes states to satisfy the monitoring requirements of Subpart UUUUa by requiring reporting according to Part 75. *Id.* at 44,810. It does not identify that monitoring as a procedure that would be used in lieu of Appendix A test methods for determining compliance with the specified standards of performance.

Moreover, some clarification regarding the use of Part 75 data is needed. As EPA has previously recognized, although EGUs report substitute data for CO_2 concentration and volumetric flow for periods when quality-assured data are not recorded by the CEMS, EPA has repeatedly recognized those reported substitute values are not appropriate for enforcing rate-based performance standards. *See, e.g.*, 40 C.F.R. part 60, Subparts Da and KKKK. The final rule should make that clear. In addition, as discussed above, because EGUs monitor and report only gross (not net) output under Part 75, allowing states to set net output standards would impose monitoring beyond what is required in Part 75 and beyond what the Proposed ACE Rule appears to anticipate. At a minimum, EPA's guidelines should explicitly authorize states to base standards on gross output or to utilize another format for their standards that does not require monitoring of output (e.g., tons

[13] UARG previously described that monitoring in detail in comments on the CPP. UARG CPP Comments at 267-271.

[14] The provision also authorizes use of "alternative" or "equivalent" methods as defined in § 60.2(t) or (u). However, the references to subsections (t) and (u) appear to be erroneous. Although § 60.2 includes definitions of "alternative" and "equivalent" methods, there are no lettered subsections in that provision.

of CO_2 per year or hour) as discussed above in Sections III.D and III.E. To the extent states want to deviate from Part 75 and require monitoring of net output, the guidelines should require states to consider and justify the additional costs.

With respect to recordkeeping, Proposed § 60.5790a also appropriately specifies that EGUs relying on Part 75 monitoring to demonstrate compliance should not be subject to additional recordkeeping. 83 Fed. Reg. at 44,810-11. However, the language in subsection (c) is too limited. As drafted, the provision appears to apply only to states that require use of "net generation" and that specify "an annual emissions standard." *Id.* at 44,810, Proposed 40 C.F.R. § 60.5790a(c). Those qualifications should be removed. Part 75 recordkeeping should be sufficient in any state that specifies use of Part 75 data to demonstrate compliance.

B. EPA Should Clarify the Requirements for States Specifying Alternative Monitoring, Recordkeeping, and Reporting.

EPA recognizes that states have primary responsibility for establishing monitoring, recordkeeping, and reporting requirements and provides that states may adopt alternatives in lieu of relying on Part 75. *Id.* at 44,810, Proposed 40 C.F.R. § 60.5785a(a)(2). Although UARG does not object in principle to this flexibility, states' authority to adopt alternatives should not be unlimited. Even small changes to existing requirements can impose significant implementation costs by creating inconsistencies or redundancies. For example, changes to the stringency of specifications for validating data could require sources to maintain an entirely separate database of emissions data to account for such changes. Even if EPA cannot prohibit states from designing their own monitoring and reporting requirements, EPA should require states to consider and justify the costs associated with imposing new or different requirements.

EPA also should clarify the proposed requirement to include "procedures for determining substitute data" in Proposed 40 C.F.R. § 60.5785a. *Id.* at 44,810, Proposed 40 C.F.R. § 60.5785a(a)(2)(vi). As noted above, EPA has long recognized in implementation of the NSPS that use of substitute data is not appropriate when determining compliance with "not to be exceeded" standards. The CPP also did not authorize use of substitute data to demonstrate compliance with rate-based emission standards such as those expressed in lb CO_2/MWh. 40 C.F.R. §§ 60.5860(a)(2)(i), 60.5880. EPA did, however, require use of missing data substitution procedures for mass-based standards (i.e., those expressed as a tons cap). 40 C.F.R. § 60.5860(b)(1). The rationale for that unprecedented requirement was that because compliance with a mass-based standard cannot be calculated without a complete data set (i.e., data for every hour), such a standard cannot be applied over an extended compliance period like the multi-year compliance periods authorized in that rule. The result should be no different in these guidelines. Only those states adopting mass-based standards applicable over an extended compliance period or authorizing trading should be required (or allowed) to specify procedures for substitute data.

VI. Certain Aspects of the Regulatory Impact Analysis Require Revision.

Consistent with Executive Orders 12866, 13563, and 13771,[15] EPA has prepared a Regulatory Impact Analysis ("RIA") that assesses the costs and benefits of the Proposed ACE Rule.[16] The ACE RIA uses the CPP as the baseline regulatory case and includes four illustrative alternative regulatory scenarios—a "No CPP" case, a policy case producing a 2 percent heat rate improvement at $50/kW, a policy case producing a 4.5 percent heat rate improvement at $50/kW, and a policy case producing a 4.5 percent heat rate improvement at $100/kW. ACE RIA at ES-1, ES-3. The ACE RIA predicts costs at both their present value and at equivalent annualized values

[15] 58 Fed. Reg. 51,735 (Oct. 4, 1993); 76 Fed. Reg. 3821 (Jan. 21, 2011); 82 Fed. Reg. 9339 (Feb. 3, 2017).

[16] EPA, EPA-452/R-18-006, Regulatory Impact Analyses for the Proposed Emission Guideline for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program (Aug. 2018), EPA-HQ-OAR-2017-0355-21182 ("ACE RIA").

and predicts both direct and ancillary benefits. *See, e.g.,* ACE RIA at ES-14 Tbl. ES-10. Its focus is on the period 2023 to 2037 and, more specifically the years 2025, 2030, and 2035. *Id.* at ES-4.

A. The "No CPP" Case Should Provide the Baseline for Analyses in the ACE RIA.

The ACE RIA's use of the CPP for its baseline is inappropriate and should be changed. The ACE RIA should instead use the "No CPP" case as the baseline and should focus its analyses on benefits attributable to the Proposed ACE Rule, not so-called "foregone benefits" associated with repeal of the CPP.

Longstanding guidance from OMB on the preparation of RIAs recognizes the need for a regulatory baseline to which comparisons will be made in an RIA. OMB, Circular A-4, Regulatory Analysis at 2 (Sept. 17, 2003), https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf ("Circular A-4"). Circular A-4 explains this baseline "normally will be a 'no action' baseline: what the world will be like if the proposed rule is not adopted." *Id.* The CPP is not appropriately viewed as the "no action" baseline here. The Supreme Court stayed the CPP on February 9, 2016,[17] prior to the CPP's earliest regulatory deadline.[18] For the Court to have issued the stay, it necessarily found (1) a "reasonable probability" that it would grant certiorari if the CPP were upheld by the D.C. Circuit and (2) "a fair prospect" that the Court would reverse a D.C. Circuit decision that upheld the CPP. *See Maryland v. King*, 133 S. Ct. 1, 2-3 (2012) (Roberts, C.J., in chambers); *Hollingsworth v. Perry*, 558 U.S. 183, 190 (2010) (per curiam); *see also* Supreme Court Rule 23.[19] In short, none of the CPP's requirements has yet been triggered, and there is at least a fair prospect that none of them ever will

[17] *West Virginia v. EPA,* 136 S. Ct. 1000 (2016).

[18] The CPP required states to submit either an implementation plan or a request for an extension of the deadline for such a plan by September 2016. 80 Fed. Reg. at 64,669.

[19] Although deadlines for actions required by the CPP had not yet passed, the Court had been advised that states and utilities affected by the Plan were already incurring expenses and making irrevocable decisions in preparation for meeting those deadlines.

be. Thus, the world does not currently reflect implementation of the CPP. Assuming its implementation is, therefore, not an appropriate baseline. Instead, assuming the absence of the CPP—the "No CPP" case—best reflects the real world.

Furthermore, the Proposal that is the subject of the ACE RIA would not repeal the CPP. EPA previously proposed to repeal that rule and prepared a separate RIA that assessed the costs and benefits of that proposal.[20] The Proposed ACE Rule is a different action than the repeal, albeit one that will not be finalized unless EPA has previously repealed the CPP or acts simultaneously do so.[21] Thus, the CPP will not exist or represent the real world by the time an ACE rule is finalized. This confirms that treating the CPP as the base case in the ACE RIA is inconsistent with Circular A-4.

Instead, the world if and when an ACE rule is finalized will be one in which the CPP has not been implemented and has been repealed. The "No CPP" alternative is the one that reflects this reality. Accordingly, the "No CPP" alternative should be the base case for the ACE RIA and the ACE RIA should discuss costs and benefits from this starting point. The ACE RIA should then show that the ACE rule will decrease emissions of CO_2 and other pollutants and produce climate and other ancillary benefits compared to the "No CPP" baseline. These will be actual, projected benefits, in contrast to the purported "foregone benefits" that are currently reported.

B. The ACE RIA Treats the Geographic Extent of Benefits and Discount Rates Appropriately.

In other critical aspects, the ACE RIA is consistent with both the Act and the guidance provided in Circular A-4. In particular, the ACE RIA appropriately considers only domestic benefits of the Proposal and includes costs and benefits using both a 3% and a 7% discount rate. ACE RIA at ES-5 Tbl. ES-1. The RIA that accompanies any final ACE Rule should retain these approaches.

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[20] EPA, EPA-452/R-17-004, Regulatory Impact Analysis for the Review of the Clean Power Plan: Proposal (Oct. 2017), EPA-HQ-OAR-2017-0355-0110 ("Repeal RIA").

[21] The CPP and the Proposed ACE Rule are incompatible and would not therefore apply simultaneously.

Because the purpose of the Proposed ACE Rule is to reduce the effect of CO_2 emitted from power plants on climate,[22] the ACE RIA appropriately considers the climate benefits of reducing CO_2 as the "'targeted pollutant'" benefits. *Id.* at ES-10. These benefits are estimated in the ACE RIA based on the *domestic* social cost of carbon. *Id.* Although EPA cited estimates of the *global* social cost of carbon when it promulgated the CPP,[23] the Agency's present approach is the correct one. First, the present approach is consistent with the purpose of the CAA, which is "protect[ion] and enhance[ment of] the quality of the *Nation's* air resources [for] . . . *its* population."[24] CAA § 101(b)(1) (emphasis added); *see also* 74 Fed. Reg. at 66,514 (Dec. 15 2009) ("It is the Administrator's view that the primary focus of the vulnerability, risk, and impact assessment is the United States."). Second, the present approach follows the direction of Circular A-4 that RIAs "focus on benefits and costs that accrue to citizens and residents of the United States." Circular A-4 at 15, 25. Third, this approach reflects Executive Order 13783, which reaffirms the importance of following the guidance of Circular A-4 with regard to the treatment of domestic versus international impacts when valuing changes in emissions of greenhouse gases, including CO_2.[26] Exec. Order No. 13783, § 5(c), 82 Fed. Reg. at 16,096. Thus, the ACE RIA's focus on domestic costs and benefits of the Proposed ACE Rule is consistent with both law and applicable guidance.

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[22] 83 Fed. Reg. at 44,748.

[23] *See, e.g.*, 80 Fed. Reg. at 64,680 Tbl 1.

[24] Certain provisions of the Act are designed to address international issues, *see, e.g.*, CAA § 115, but those are not the provisions on which EPA is relying for the Proposed ACE Rule. The Proposal addresses CO_2 emissions only from domestic energy generation.

[25] Although Circular A-4 permits an Agency to decide that it wants to evaluate international benefits and costs of a rule, these benefits and costs are to be reported separately. Circular A-4 at 15.

[26] The justification for focusing on the domestic benefits of the Proposed ACE Rule is further explained in the attached comments by Smith and Bloomberg on the Repeal RIA. A.E. Smith & S.J. Bloomberg, NERA Economic Consulting, Technical Comments on EPA's Regulatory Impact Analysis for the Proposed Repeal of the Clean Power Plan at 35-37 (Apr. 26, 2018) ("Smith & Bloomberg") (Attachment G to these comments).

The ACE RIA's use of both a 3% and a 7% discount rate to estimate both the expected costs and benefits of the Proposed ACE Rule, ACE RIA at ES-4, is similarly consistent with the guidance provided by Circular A-4. Recognizing that people commonly "plac[e] a higher value on current consumption than on future consumption," Circular A-4 endorses the use of discounting "to adjust the estimated benefits and costs for differences in timing." Circular A-4 at 32. It specifically recommends use of 3% and 7% percent discount rates for RIAs.[27] *Id.* at 34. Use of these rates in the ACE RIA is appropriate.

C. The ACE RIA's Presentation of the Proposal's Benefits Requires Revision.

In addition to estimating the direct benefits of reducing CO_2, the ACE RIA also estimates "ancillary 'co-benefits'" to health attributable to changes in fine particulate matter ("$PM_{2.5}$") and ground-level ozone.[28] ACE RIA at ES-10. Some of these purported benefits are quantified and monetized; others are not. *Id.* at 4-18 Tbl. 4-4. In addition, the ACE RIA includes an analysis looking at alternative approaches to estimating $PM_{2.5}$-related premature mortality "to evaluate uncertainty." *Id.* at 4-31. Although including discussion in the ACE RIA of ancillary benefits of the regulation is appropriate, the approaches in the ACE RIA to estimating and reporting the Proposal's benefits require revision.[29]

Because CO_2 is the pollutant targeted by the Proposed ACE Rule, *id.* at ES-10, it is vital that EPA assess and report benefits first in relation to CO_2. Unless the analysis is conducted and presented in this manner, it will not be apparent whether the Proposal is "the best available method

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[27] To the extent some may argue for a discount rates lower than 3%, Smith and Bloomberg, have explained why this is not appropriate. Smith & Bloomberg at 40-43.

[28] The ACE RIA refers to estimates of "forgone" benefits. *See, e.g.*, ACE RIA at 4-1. When the appropriate "No CPP" baseline is used, however, it will be apparent that these are actually projected benefits of the Proposed ACE Rule.

[29] Circular A-4 recommends an RIA include discussion of ancillary benefits and countervailing risks. Circular A-4 at 26.

of achieving the regulatory objective," Exec. Order. No. 12866 § (1)(b)(5), 58 Fed. Reg. at 51,736, i.e., for "ensur[ing] that coal-fired power plants … address their contribution to climate change by reducing their CO_2 intensity." 83 Fed. Reg. at 44,748. If the benefits related to CO_2 reduction are not reported separately, the rule might be deemed appropriate almost entirely on the basis of ancillary benefits that are not relevant to achieving the rule's objective. The separate benefits of the CO_2 reductions expected from the Proposed ACE Rule are, in fact, reported in both the ACE RIA and in the ACE Proposal itself. ACE RIA at ES-6, Tbl. ES-2; 83 Fed. Reg. at 44,794, Tbl. 17. The EPA Administrator thus has a basis for assessing whether these benefits justify finalizing the rule.

The ACE RIA and the Proposed ACE Rule also report and quantify some ancillary benefits associated with incidental reductions in $PM_{2.5}$ and ozone. ACE RIA at ES-18 Tbl. ES-14; 83 Fed. Reg. at 44,795 Tbl. 20. Although consideration of a regulation's ancillary benefits is appropriate, when those benefits are attributable to reductions in pollutants that are separately regulated under the Act, those estimates should not be inconsistent with the existing regulatory regimes for those pollutants.

$PM_{2.5}$ and ozone are both criteria air pollutants and are regulated under the NAAQS program.[30] 40 C.F.R. §§ 50.7, 50.10, 50.13, 50.18. EPA sets primary NAAQS at the level "requisite to protect the public health" with "an adequate margin of safety." CAA § 109(b)(1). Thus, when establishing NAAQS for $PM_{2.5}$ and ozone, EPA found that exposure to these pollutants does not endanger public health in areas where the NAAQS are attained.[31] The NAAQS were established after due consideration by the EPA Administrator of the relevant health science, with the assistance

[30] For this reason, neither ozone nor $PM_{2.5}$ are candidates for regulation under section 111(d) of the Act. CAA § 111(d)(1)(A)(i).

[31] 80 Fed. Red. 65,292, 65,301 (Oct. 26, 2015) ("[T]he Administrator concludes that [an ozone standard of 70 ppb] will be requisite to protect public health with an adequate margin of safety. "); 78 Fed. Reg. 3086, 3164 (Jan. 15, 2013) ("The Administrator concludes that this suite of standards would be requisite to protect public health with an adequate margin of safety against health effects potentially associated with long- and short-term $PM_{2.5}$ exposures. ").

of the Clean Air Scientific Advisory Committee. The Act requires that each NAAQS be reviewed and revised as appropriate at least every five years. *Id.* § 109(d)(1). Indeed, the Agency is currently reviewing the NAAQS for both $PM_{2.5}$ and ozone[32] and will make revisions to them if the Administrator finds that newer science warrants such action.

Accordingly, any estimates in the ACE RIA of ancillary benefits from incidental reductions in $PM_{2.5}$ and ozone should be consistent with the NAAQS program and the current NAAQS. Estimating benefits from exposures in areas where the NAAQS are attained would be inconsistent with the findings that those standards protect public health with an adequate margin of safety. Moreover, estimating benefits from reducing exposures in areas where the NAAQS are not yet attained risks double-counting the benefits of those reductions because the Act already requires measures in those areas to provide for attainment of the NAAQS as expeditiously as practicable. *Id.* §§ 181(a)(1), 188(c). The ACE RIA should not include benefits that result from emissions reductions already required by other programs. *See* Circular A-4 at 20. Thus, the ACE RIA should, at most, estimate the benefits of further reducing exposures to concentrations above the level of the NAAQS.[33]

The ACE RIA's current base estimate of $PM_{2.5}$-related premature mortality avoided is inconsistent with the Agency's finding that the current NAAQS protects public health, allowing an adequate margin of safety.[34] It is based on "a log-linear concentration-response function" that

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[32] 83 Fed. Reg. 29,785 (June 26, 2018); 79 Fed. Reg. 71,764 (Dec. 3, 2014).

[33] Although the NAAQS protect public health, they do not necessarily eliminate all risk. Thus, they are not written in such a way that the level of the NAAQS can never be exceeded if the NAAQS is attained. For example, the annual NAAQS for $PM_{2.5}$ is attained if the 3-year annual average $PM_{2.5}$ concentration does not exceed the level of NAAQS. 40 C.F.R. § 50.18 (b). Thus, the level of the annual NAAQS could be exceeded in a given year in an attainment area and the NAAQS would still be attained, if concentrations in the other years considered in determining the 3-year average fell below the NAAQS level.

[34] The current base estimate should at most be a sensitivity analysis, if it is retained at all.

predicts benefits from exposure to any $PM_{2.5}$ concentration above zero. ACE RIA at 4-21. To be consistent with the current regulatory regime for $PM_{2.5}$, that approach should be replaced by one that focuses on estimating effects from exposures above the level of the $PM_{2.5}$ NAAQS. EPA has done this calculation as a sensitivity analysis. *Id.* at 4-40 Tbl. 4-12. The estimated $PM_{2.5}$-related premature mortality associated with exposure above the level of the annual NAAQS is less than 1 percent of that reported in the current base estimate. *Id.*; 83 Fed. Reg. at 44,790. Other estimates of health benefits from incidental reductions of $PM_{2.5}$ and ozone should similarly be revised to be consistent with the current regulatory regimes for $PM_{2.5}$ and ozone and the estimated ancillary health benefits of the Proposed ACE Rule will likely be similarly reduced.[35]

Even after the ancillary health benefits reported in the ACE RIA have been revised to be consistent with EPA's current NAAQS, those benefits may still be over-estimated. The concentration-response functions on which EPA has chosen to rely in the ACE RIA to produce estimates of health benefits do not capture the full range of uncertainty in the underlying health effects database.[36] The analyses reported in the ACE RIA do not appear to take into account the statistical significance (or lack thereof) of the associations on which they are based or the existence of alternative analyses that do not find such associations.[37] For example, Krewski et al. (2009), on

[35] EPA has recognized that tropospheric ozone (e.g., in the ambient air) "provides supplemental shielding of UV-B radiation in the mid-wavelength band (280-315 nm), thereby potentially reducing UV-B related human and ecosystem health effects and materials damage." EPA, EPA 600/R-10-10/076F, Integrated Science Assessment for Ozone and Related Photochemical Oxidants at 1-13 (Feb. 2013), https://www.epa.gov/isa/integrated-science-assessment-isa-ozone-and-related-photochemical-oxidants. The possibility that reduced levels of ozone in the troposphere as a result of the Proposed ACE Rule would result in such effects should be acknowledged as a countervailing risk, even if that risk cannot be quantified. *See* Circular A-4 at 26.

[36] An RIA must "analyze[] and present[]" uncertainties. Circular A-4 at 38.

[37] For estimates of effects other than premature mortality, the sources of the estimates are generally not identified. *See* ACE RIA at 4-32 Tbl. 4-5. This is contrary to OMB's guidance that RIA's should be transparent. Circular A-4 at 3.

which the ACE RIA relies to estimate $PM_{2.5}$-related premature deaths, *see* ACE RIA at 4-20, includes numerous, well-controlled analyses that do not find statistically significant associations between $PM_{2.5}$ exposure and mortality. *See, e.g.*, Daniel Krewski et al., Health Effects Institute Research Report No. 140, *Extended Follow-up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality* at 50 Tbl. 15 (2009) ("Krewski et al. (2009)").Similarly, Jerrett, et al. (2009), on which ozone-related mortality estimates in the ACE RIA are based, did not report statistically significant changes in ozone-related "[a]ny cause" premature mortality when ozone exposure alone was modeled or when $PM_{2.5}$ exposure was also accounted for in the model. *See* Michael Jerrett et al., *Long-Term Ozone Exposure and Mortality*, 360 N. Engl. J. Med. 1085, 1092 Tbl. 3 (2009), ("Jerrett et al. (2009)"), https://www.nejm.org/doi/full/10.1056/NEJMoa0803894. Indeed, when $PM_{2.5}$ was included in the model, the association between ozone and "[a]ny cause" mortality was negative. *Id.*

Furthermore, it is not clear that the ACE RIA has fully accounted for emission reductions from coal-fired power plants that result from existing regulatory programs. The ACE RIA indicates that emission reductions for MATS, CSAPR, and the CSAPR Update Rule have been taken into account. ACE RIA at 8-4. Emissions reductions required by other on-the-books regulations, including the NAAQS for SO_2 promulgated in 2010 and the 2015 ozone NAAQS, may not have been accounted for although they will occur before the 2025 to 2035 period modeled for the ACE RIA. If power plant emissions are overstated, the benefits associated with the Proposed ACE Rule will also be overstated.[38]

[38] Some commenters have contended that the Proposed ACE Rule "could result in up to 1,400 more premature deaths." Comments of Harold P. Wimmer, National President and CEO, American Lung Association at 1, EPA-HQ-OAR-2017-0355-22171. This contention is misguided. It is based on a comparison of the various illustrative scenarios presented in the ACE RIA to the CPP. As explained above, the CPP is not in effect and is unlikely ever to go into effect. It is therefore, not the appropriate starting point for evaluating the benefits of the Proposed ACE Rule. Instead, the

Finally, the ACE RIA's list of unquantified ancillary benefits of the Proposed ACE Rule is overly broad.[39] Although inclusion in an RIA of a description of benefits that cannot be quantified is appropriate, Circular A-4 at 18, mention of speculative benefits is unwarranted. The ACE RIA acknowledges that in some cases the evidence for a causal association between exposure to pollutants affected by the Proposal and the unquantified benefit is uncertain "or there are other significant concerns over the strength of the association." ACE RIA at 4-47 Tbl. 4-17 n.3. The ACE RIA would be improved if it omitted discussion of benefits that are highly uncertain, not just difficult to quantify.

VII. Definitions, Applicability, and Regulatory Language (Comment C-4)

UARG has identified several errors, ambiguities, or other issues in the proposed regulatory language for the ACE Rule and proposed Subpart Ba. EPA should address these issues in the final rule.

Definition of "existing" unit: EPA incorrectly identifies the "existing" units subject to the ACE Rule as those that "commenced construction on or before *August 31, 2018*," i.e., the publication date of the proposed ACE Rule. 83 Fed. Reg. at 44,810, Proposed 40 C.F.R. § 60.5775a(a) (emphasis added). Section 111 defines "existing source," however, as any stationary source that is not "a new source." CAA § 111(a)(6). Accordingly, the correct date for defining "existing" coal-fired utility boilers for purposes of this rule should be January 8, 2014, which is the date defining what constitutes a "new" source under the 2015 NSPS. 40 C.F.R. § 60.5509(a).

Exclusions: The proposed regulatory language includes a provision describing what EGUs are not covered by the ACE Rule. 83 Fed. Reg. at 44,810, Proposed 40 C.F.R. § 60.5780a. One of

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appropriate comparison is to the "No CPP" case. That comparison shows reductions in $PM_{2.5}$- and ozone-related premature mortality and other health effects if the Proposed ACE Rule is adopted. For the reasons explained above, however, those potential benefits from the Proposal are overstated in the ACE RIA.

[39] *See* ACE RIA at 4-46 to 4-47, Tbl. 4-17.

these exclusions is a "stationary combustion turbine that meets the definition of either a combined cycle or combined heat and power combustion turbine." *Id.*, Proposed 40 C.F.R. § 60.5780a(a)(3). This language creates confusion, however, because it suggests that stationary combustion turbines that *do not* meet the definition of a combined cycle turbine (i.e., simple cycle combustion turbines) *are not* excluded from the ACE Rule. The preamble is clear that EPA does not intend to promulgate emission guidelines in this rulemaking for any stationary combustion turbines. EPA should revise the regulatory language so as not to suggest that simple cycle combustion turbines are subject to state plans. UARG believes that the explicit exclusion is not necessary, since Proposed 40 C.F.R. § 60.5775a(b) is clear that only a "steam generating unit" qualifies as an affected EGU, 83 Fed. Reg. at 44,810, and stationary combustion turbines do not meet the proposed definition of "steam generating unit." If EPA wants to retain explicit exclusionary language, however, it should simply state that an affected EGU does not include "a stationary combustion turbine."

Further, EPA also proposes to exclude any steam generating unit that "is, and always has been, subject to a federally enforceable permit limiting annual net-electric sales to one-third or less of its potential electric output, or 219,000 MWh or less." *Id.* at 44,810, Proposed 40 C.F.R. § 60.5780a(a)(2). EPA should delete the requirement that the unit "always has been" subject to such a limit on its output, so that a source may, at its election, accept such a permit limit and avoid being subject to a state plan. Doing so will allow sources to minimize their compliance costs—and save states the burden of developing state plan provisions governing those sources—while achieving additional CO_2 emission reductions.

Definition of "combined cycle combustion turbine": The proposed regulations use the term "combined cycle combustion turbine" but do not define that term. To eliminate ambiguity, EPA should include a definition of that term (and the related term "heat recovery steam generating unit") that uses the definitions currently used in 40 C.F.R. § 60.5880.

Definition of "steam generating unit": EPA should revise the proposed definition of "steam generating unit," 83 Fed. Reg. at 44,812, Proposed 40 C.F.R. § 60.5805a, to specify that it does not include the heat recovery steam generating unit portion of a combined cycle combustion turbine.

Definition of "valid data": The proposed regulations define the term "valid data." *Id.* But that term is not used anywhere in proposed Subpart UUUUa. To avoid confusion, the proposed definition should be deleted.

Cross-reference regarding consideration of source-specific factors: In describing what standards of performance must be included in a state plan, EPA's proposed regulatory language provides that a state "may consider the source-specific factors included in § 60.24(e)" when establishing a standard. *Id.* at 44,809, Proposed 40 C.F.R. § 60.5755a(a)(2)(i). This cross-reference is incorrect, as § 60.24(e) is part of Subpart B, whereas the ACE Rule would be governed by Subpart Ba (if finalized). Accordingly, the correct cross-reference is to 40 C.F.R. § 60.24a(e).

Subpart Ba definition of "emission guideline": In proposed Subpart Ba, EPA repeatedly defines the term "emission guideline" by stating that it must include information on the "degree of emission *reduction* achievable through the application of the" BSER. 83 Fed. Reg. at 44,804, Proposed 40 C.F.R. §§ 60.21a(e), 60.22a(b)(2) (emphasis added). This definition is inconsistent with the statutory language, which states that a standard of performance must reflect "the degree of emission *limitation* achievable through the application of the" BSER. CAA § 111(a)(1) (emphasis added). EPA's proposed definition inappropriately suggests that a standard of performance under section 111 must require some incremental reduction in a source's emissions. EPA should replace the word "reduction" with "limitation" in the two provisions cited above.

Cross-reference regarding general NSPS provisions: Proposed 40 C.F.R. § 60.24a(b)(1) states that "[m]ethods other than those specified in Appendix A to this part or an applicable subpart of this part may be specified in the plan if shown to be equivalent or alternative methods as defined in § 60.2(t) and (u). 83 Fed. Reg. at 44,805. However, § 60.2 does not have a paragraph (t) or (u), and it is not clear which parts of that section EPA intended to refer to. EPA should correct the cross-reference in the proposed provision.

Cross-reference regarding federal plans: Proposed 40 C.F.R. § 60.27a(e)(2) states that EPA may provide for less stringent standards of performance or longer compliance schedules "in accordance with the criteria specified in § 60.24a(f)." 83 Fed. Reg. at 44,806. This appears to be a typo, as the criteria to which EPA refers are located at § 60.24a(e).

Comments on the Proposed Revisions to the Section 111(d) Implementing Regulations (Subpart Ba) (Comment C-50)

VIII. Eliminating Health-and Welfare Distinction

UARG supports EPA's proposal to eliminate an alleged discrepancy in language between public health-based and welfare-based pollutants that currently exist in the implementing regulations. 83 Fed. Reg. at 44,773. Some have read 40 C.F.R. § 60.24(c) to require states' standards of performance to be equally as stringent as the EPA's emission guidelines for health-based pollutants, while 40 C.F.R. § 60.24(d) allows states to apply less stringent standards for public-welfare based pollutants. EPA has described the difference in language as a distinction that is not "unambiguously required under section 111(d) or any other applicable provision." 83 Fed. Reg. at 44,773. UARG seeks to clarify, however, its belief that there was never a distinction between health-based and welfare-based pollutants under the existing regulations, as 40 C.F.R. § 60.24(c) contains a caveat that says "[e]xcept as provided in paragraph (f) of this section." 40 C.F.R. § 60.24(f) provides states with authority to apply less stringent standards without any distinction between health and welfare-based pollutants.

EPA is correct, however, that to the extent such a distinction exists, it has no basis in the statute. *See* CAA § 111. Because there has been confusion on this point, UARG views EPA's current proposal as an effort to conclusively eliminate any potential confusion that the two terms ever established different standards.

IX. Including Useful Life and Other Factors in Variance Provision (Comments C-22, C-23, C-57, C-58)

UARG agrees with EPA's proposed elimination of restrictions on states' authority to consider remaining useful life and other factors in setting performance standards found in Subpart B of the existing regulations. 83 Fed. Reg. at 44,773. EPA has solicited comment on how a new variance provision can permit states to take into account remaining useful life[40] and other factors. *Id.* EPA proposes amending the variance provision to reflect additional factors that may be considered in setting performance standards. *Id.* This amendment would bring the implementing regulations in line with section 111(d)(1)(B) of the statute, which requires EPA to permit states to take into account factors, including remaining useful life, when applying a standard of performance to an individual source. CAA § 111(d)(1)(B). As EPA noted, the current regulation was promulgated prior to the addition to section 111(d)(1)(B) and never updated to reflect the amended statute. 83 Fed. Reg. at 44,769. UARG recognizes the addition to section 111(d)(1)(B) does not limit when states may consider the remaining useful life or other factors when applying a standard of performance, and thus, EPA has no authority to restrict when states may consider such factors.

X. Standards of Performance Definition (Comment C-56)

UARG also supports EPA's proposal to clarify that standards of performance in state plans may take the form of work practice standards consistent with section 111(h), so long as the other criteria of section 111(h) have been met. *Id.* at 44,773. EPA requested comment on means of tracking and incorporating section 111(a)(1) and 111(h) for the regulatory definition of "standard of performance." *Id.*

EPA acknowledged the implementation regulations are inconsistent with the current statute as the regulations refer to "emission standards" rather than "standards of performance." CAA § 111(a)(1); 40 C.F.R. § 60.24(b)(1). Moreover, the existing "emission standards" definition is incomplete as it includes some, but not all forms of alternative standards provided in section 111(h). 40 C.F.R. § 60.24(b)(1). Currently, the implementation regulations account only for equipment

[40] UARG disagrees with EPA's characterization of the consideration of remaining useful life or these other factors as being a "variance." States do not need to invoke a regulatory "variance" to account for remaining useful life or other relevant factors in either the standard or in the implementation of the plan because these factors are expressly identified in the statute.

standards but fail to mention work practice or operational standards that section 111(h) covers. EPA's proposed changes would update the regulation to make it consistent with the clear language of section 111(h).

Finally, as EPA has recognized with intra-source emissions averaging, UARG agrees that EPA should continue to endorse state authority to grant sources ability to meet individual standards in a variety of ways to bolster compliance with CAA standards, and should broaden the compliance techniques that can be considered by states. *See* Section IV.

XI. No Presumptive Emission Standards in Emission Guidelines

UARG agrees that section 111 does not require EPA to provide a presumptive emission standard in its emission guidelines and supports EPA's proposal to update the definition of "emission guideline" to require only the inclusion of information on the degree of emission limitation achievable through the application of BSER. 83 Fed. Reg. at 44,771. EPA stated that the preambles for both the proposed and final implementing regulations suggest an "emission guideline" would presumptively reflect the degree of emission limitation achievable by BSER. *Id.* UARG believes this interpretation is not definitive as the regulations are not explicit in this regard, and nothing in section 111 can be construed as compelling EPA to provide a presumptive emission standard. Regardless, UARG agrees that redefining "emission guideline" as "a final guideline document published under § 60.22a(a)" would prevent any future confusion regarding its meaning. *Id.* at 44,804, Proposed 40 C.F.R. § 60.21a(e). The proposed amendment would give "emission guideline" a definition that is consistent with the statute and that reflects the ordinary meaning of the term.

XII. New Time Requirements (Comments C-52, C-53, C-54, C-55)

UARG generally supports EPA's proposed changes to the deadlines for submission of state plans, EPA approval of state plans, and EPA's issuance of a federal plan to make those deadlines identical to those provided in section 110 for SIPs. *Id.* at 44,771. EPA requested comments on the proposed timing requirements for prospective emission guidelines and ongoing emission guidelines to incorporate the new proposed timing requirements. *Id.*

Under the proposed Subpart Ba regulations, states would be required to submit a state plan within three years of the promulgation of final emission guidelines, unless otherwise specified in the applicable guideline. *Id.* at 44,804, Proposed 40 C.F.R. § 60.23a(a)(1). Based on its extensive experience working with states, EPA believes that the current nine month deadline to create a state plan under section 111(d) is insufficient. *Id.* at 44,769. In EPA's estimation, providing states additional time to craft state plans will allow them to interact and work with EPA while maintaining flexibility in complying with section 111(d). *Id.* UARG agrees that states should have at least three years to develop, adopt, and submit state plans to EPA implementing emission guidelines. If states commenting on the Proposed Subpart Ba regulations indicate that three years is insufficient, UARG encourages EPA to give effect to those comments and adopt a longer time period for state plan submission in its Subpart Ba regulations.

EPA also proposes giving the Agency 12 months to take action on the state plan once it is received. *Id.* at 44,806, Proposed 40 C.F.R. § 60.27a(b). EPA finds prolonging the review period from the current 4 months to 12 months would provide the Agency adequate time to review and follow the necessary notice-and-comment rulemaking procedures. *Id.* at 44,771. EPA also believes the deadline to promulgate a federal plan for states that fail to submit an approvable plan should be extended from six months to two years. *Id.* at 44,806, Proposed 40 C.F.R. § 60.27a(d). The proposed time requirements are meant to mirror the deadlines laid out in section 110. *See* CAA § 110. UARG agrees that the section 110(c) time requirements are more appropriate than the deadlines currently in effect.

Regardless of whether EPA extends the deadlines for states to submit their plans, nothing prevents states from submitting their plans ahead of those deadlines. EPA should clarify, however, that if a state does submit its plan early, the provisions regarding affected source compliance deadlines (e.g., the requirement for enforceable progress increments) begin to run no earlier than the date required for plan submittal. Currently, a state is required to provide increments of progress if its compliance schedule extends more than 12 months from the date the plan is due. 40 C.F.R. § 60.24(e)(1). EPA proposes extending this trigger to 24 months. 83 Fed. Reg. at 44,805, Proposed 40 C.F.R. § 60.24a(d)(1). As discussed in Section III.C above, UARG believes it is more appropriate to tie the requirement for enforceable progress increments to the date of plan approval, while providing that in any event the timeline for that requirement will not begin to run until the date state plan submissions are due. If EPA fails to clarify that the clock for enforceable progress increments does not begin to run until the date for plan submission (at the earliest), states could refrain from submitting completed plans early in fear that the 24 month time period would begin sooner. Instead, EPA should encourage states to submit plans as early as possible to ensure EPA has adequate time to review them and to prevent all state plans from being submitted at the last minute.

Comments on the Proposed Revisions to NSR Applicability Provisions

XIII. UARG Agrees NSR Revisions Are Needed. (Comments C-62, C-67)

UARG supports EPA's proposal to revise the NSR program's applicability provisions. EPA's ever more expansive interpretations of the CAA's NSR applicability provisions to existing sources has been a source of regulatory uncertainty for the utility industry that has discouraged source owners from carrying out projects that would maintain or improve the safe, reliable, and efficient operation of those units. *See* EPA, "New Source Review: Report to the President," at 1 (June 2002), https://www.epa.gov/sites/production/files/2015-08/documents/nsr_report_to_president.pdf ("As applied to existing power plants … EPA concludes that the NSR program has impeded or resulted in the cancellation of projects which would maintain and improve reliability, efficiency and safety of existing energy capacity. Such discouragement results in lost capacity, as well as lost opportunities to improve energy efficiency and reduce air pollution."). The current approach to determining NSR applicability, at a minimum, leaves sources vulnerable to after-the-fact second-guessing by EPA and third parties.

This Proposal provides a timely opportunity to carry out long-needed revisions to the NSR program's applicability provisions, in light of EPA's previous NSR enforcement efforts involving heat rate improvement projects. The types of projects included on EPA's candidate technologies list—as well as other efficiency projects excluded from that list—have since 1999 been targeted by EPA and citizen plaintiffs as allegedly triggering the CAA's NSR provisions. Indeed, shortly after EPA launched its coal-fired power plant NSR enforcement initiative in November 1999, EPA issued a formal applicability determination for a turbine upgrade at Detroit Edison's Monroe Power Plant called the Dense Pack project. In that determination, EPA cited the efficiency improvement resulting from the project as a major factor weighing against a finding that the project was routine maintenance, repair or replacement ("RMRR") and thus excluded from NSR permitting requirements:

> The purpose of the Dense Pack project, to significantly enhance the present efficiency of the high pressure section of the steam turbine, signifies that the project is not routine…. It would result in greater efficiency above the level that can be reached by simply replacing deteriorated blades with ones of the same design and, in addition, will substantially increase efficiency over the original design. Specifically, the Dense Pack upgrade would not only restore the 7 percent of the efficiency rating lost over the years at each unit but would improve the unit's efficiency by an additional 5 percent over its original design capacity.

Letter from Francis X. Lyons, Reg'l Adm'r, EPA, to Henry Nickel, Hunton & Williams at 2, 3 (May 23, 2000), https://www.epa.gov/sites/production/files/2015-07/documents/detedisn.pdf, ("Detroit Edison Determination"). In contrast to what EPA stated in the 1992 WEPCo-Fix rulemaking ("EPA in no way intends to discourage physical or operational changes that increase efficiency or reliability or lower operating costs;" and "EPA declines to create a presumption that every emissions increase that follows a change in efficiency is inextricably linked to the efficiency change." 57 Fed. Reg. 32,314, 32,327 (July 21, 1992)), EPA went on to assert:

> In general, a physical change in the nature of the Dense Pack project, which provides for the more economical production of electricity, would be expected to result in the increased utilization of the affected units, and thus, increased emissions. Notwithstanding the fact the Monroe units may be high on the dispatch order, the Dense Pack project would allow Detroit Edison to produce electricity more cheaply per unit of output, thereby creating an incentive to run Units 1 and 4 above current levels.

Detroit Edison Determination at 4-5.

In the current Proposal, EPA summarizes the rationale that the Agency and citizen plaintiffs have used to claim that these and other similar heat rate improvement projects can trigger NSR: (1) heat rate improvements increase a unit's efficiency, reliability, and availability, all of which contribute to lower operating costs; (2) EGUs that operate at lower costs are preferred in the dispatch order; (3) the unit's new position in the dispatch order may lead to increased generation; and (4) that increase in generation can result in a significant emissions increase. 83 Fed. Reg. at 44,775.

As an initial matter, UARG disagrees that the heat rate improvement measures on EPA's proposed candidate technologies list—or indeed, other similar efficiency-improving projects—are the types of actions that generally would trigger NSR as major modifications. A presumption that small increases in efficiency are the predominant cause of increases in utilization of a coal-fired EGU is speculative. Efficiency improvements of the type contemplated by this Proposal may constitute RMRR of deteriorated components and do not trigger NSR. *See, e.g.*, *Nat'l Parks Conservation Ass'n v. TVA*, No. 3:01-CV-71, 2010 WL 1291335 (E.D. Tenn. Mar. 31, 2010) (finding economizer and superheater replacements RMRR). Indeed, the Proposed ACE Rule itself will require heat rate improvement projects to become routine replacements within the industry category. Moreover, efficiency improvements of 1 to 6 percent are often too small to significantly and identifiably change the dispatch of a unit in a large system, and in any event, such changes are minute in relation to the much greater fluctuations in annual utilization driven by all other factors that affect dispatch of a unit in any particular year.

Nonetheless, the fact remains that EPA and citizen plaintiffs have repeatedly targeted common component replacement projects, including heat rate improvement projects, for alleged NSR violations. In its comments on the proposed CPP, UARG identified *roughly 1,000* efficiency improvement and/or maintenance projects targeted by EPA or citizens since 1999 as allegedly violating NSR, including many projects involving the very same heat rate improvement projects included on EPA's candidate technologies list. UARG CPP Comments at 172 & Attachments A-B. That list is included as Attachment H to these comments. Those claims have led to an almost 20-year-long, and still continuing, morass of litigation. Thus, without the revisions proposed here, sources will face allegations that they have triggered NSR simply by taking action to comply with their performance standards under the Proposed ACE Rule. At the very least, this will increase the costs of implementing the rule and add delay, as source owners will be required to provide analyses demonstrating why taking certain efficiency improvement measures does not trigger NSR. The resource and administrative burdens on the States with primary responsibility for implementing existing source performance standards will be very substantial. As evidenced by the almost two decades-long NSR enforcement initiative these determinations are subject to great uncertainty and, indeed, dispute. If the permitting authority (or EPA) disagrees with the source, the source owner would have to obtain an NSR permit which is both time-consuming and expensive, or abandon the project because the cost of NSR has made it cost-prohibitive. Further, any source owner that does not project a significant increase in emissions from an efficiency measure will still face the ongoing threat of NSR litigation for years after carrying out that measure from the Agency or citizen plaintiffs second-guessing that projection.

Thus, given the overlap between the heat rate improvement projects in the Proposed ACE Rule and EPA's history of NSR enforcement over the last two decades, this Proposal provides an opportune time to reconsider the NSR program's applicability requirements to existing EGUs. UARG notes, however, that EPA's proposed changes to the NSR program are justified and necessary even in the absence of the ACE Rule. Adopting a maximum hourly emission rate increase threshold test for major modifications will promote the safe, reliable, and efficient operation of EGUs. UARG therefore urges EPA to move ahead with revising the NSR regulations, regardless of how EPA decides to proceed under section 111(d).

Because the proposed changes to the NSR program are necessary even in the absence of the ACE Rule, UARG supports the proposed scope of EPA's revisions to the NSR applicability test, which apply to any project conducted at an EGU (as defined in 40 C.F.R. § 51.124(q)). As noted above, the proposed changes are necessary to promote the safe, reliable, and efficient operation of these critical infrastructure sources, not just facilitate implementation of the emission guideline proposed here. Accordingly, applicability of the proposed threshold hourly emissions increase test should not be limited to projects that are carried out for compliance with state plans developed under the ACE Rule.

XIV. EPA's Test for Determining NSR Applicability Has Changed Repeatedly Over Time and Encompassed Several Different Concepts of "Emissions Increases."

Before addressing the specific changes EPA has proposed here for the NSR applicability provisions, some historical context is necessary to explain the evolution of EPA's NSR rules and the various "emissions increase" tests that have come before the current approach. This context reveals that the concepts of "modification" and "major modification" used in the NSPS and NSR programs are the result of shifting interpretations of the relevant statutory provisions through the interaction of legislation, EPA rulemaking, and judicial decisions. History also reveals that contemporaneously with the enactment of the statutory NSR programs (in the 1977 CAA Amendments) and until the late 1980s, EPA did not consider increases in the hours of operation or rate of production within the confines of already existing stationary source operations to be relevant to the determination of actual emission increases caused by a physical or method of operation change. Over time, the analysis required to trigger NSR has changed repeatedly and has reflected several different concepts of what type of "emissions increase" may constitute a major modification under that program.

The concept of a "modification" to an existing source triggering regulatory requirements in the same manner as construction of an entirely new source originated with the section 111 NSPS program in the CAA Amendments of 1970. Section 111, then as now, defined "modification" as "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." CAA § 111(a)(4).

The Agency adopted implementing regulations in 1971 that largely defined "modification" to match the statutory definition. 40 C.F.R. § 60.2; 36 Fed. Reg. 24,876 (Dec. 23, 1971). However, in 1975 EPA promulgated a supplemental regulatory provision to "clarify the phrase in the definition of modification 'increases the amount of any air pollutant.'" 39 Fed. Reg. 36,946 (Oct. 15, 1974) (proposed rule); *see also* 40 Fed. Reg. 58,416 (Dec. 16, 1975) (final rule). Under this new provision, EPA clarified that a modification as defined in CAA § 111(a)(4) is "any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies," and that the term "emission rate" refers to a unit's hourly emissions in kilograms per hour ("kg/hr"). 40 C.F.R. § 60.14(a), (b). Thus, EPA's NSPS regulations—which are still in effect—determine whether a "modification" as defined in CAA section 111(a)(4) has occurred based on analysis of the unit's maximum hourly emissions before and after the project, holding everything that affects the source's hourly emission rate constant except for the effects of the project in question. This application of the definition of modification has consistently been the case for more than four decades.

Meanwhile, EPA's first NSR program was established by regulation in 1974—several years before Congress established the statutory PSD and Nonattainment NSR programs. 39 Fed. Reg. 42,510 (Dec. 5, 1974) ("1974 PSD Rule"). In that rule, EPA established a regulatory PSD program that defined "modification" to mirror the NSPS program's definition of the term—including its focus on increases in a source's hourly emission rate. In fact, the 1974 PSD Rule explicitly stated the Administrator's intent to make EPA's PSD definition of modification "consistent with the definition used in Part 60" for NSPS. *Id.* at 42,513.

Accordingly, when Congress enacted the 1977 CAA Amendments, it did so against the backdrop of an existing regulatory program for NSR. In the 1977 Amendments, Congress incorporated EPA's 1974 regulatory PSD program with some changes while creating a separate Nonattainment NSR program. Clean Air Act Amendments of 1977, Pub. L. No. 95-95, §§ 127(a) & 129, 91 Stat. 685, 731-42, 745-51 (1977) (codified at CAA §§ 160-69, 171-78). Both the PSD and Nonattainment NSR provisions define "modification" via cross-reference to the section 111 definition in the CAA's NSPS provisions. *See* CAA §§ 169(2)(c) & 171(4) (cross-referencing CAA § 111(a)). The 1977 Amendments also explicitly left in place the bulk of EPA's 1974 PSD Rule, including its use of maximum hourly emissions to define when a modification has occurred, pending the promulgation of new regulations implementing the amended statute's specific requirements. *See id.* § 168(a).

When EPA promulgated those new PSD rules in 1978, it did not disavow its 1974 definition of "modification" (which is still codified in the Code of Federal Regulations at 40 C.F.R. § 52.01(d)) or suggest that it was incompatible with the statutory PSD program. 43 Fed. Reg. 26,388 (June 19, 1978) ("1978 NSR Rule"). Instead, it left that definition in effect while adopting new provisions limiting the applicability of PSD requirements to "major modifications." The 1978 NSR Rule defined a "major modification" as "any physical change in, change in the method of operation of, or addition to a stationary source which increases the *potential emission rate* of any air pollutant regulated under the act" by amounts exceeding the program's thresholds for "major stationary sources." *Id.* at 26,403. The potential emission rate had been defined in the 1978 rules as the rate in the absence of any emission controls. Because the "major stationary source" thresholds are expressed in tons per year, the 1978 NSR Rule shifted the focus of the applicability analysis for "major modification" from hourly to annual emissions. However, it in effect retained the 1974 PSD Rule's focus on comparing maximum hourly emissions before and after a change. That is, under the 1978 NSR Rule, a project must be a "modification" within the meaning of the 1974 PSD Rule and the NSPS rule before it can be a "major modification" under NSR.

The 1978 NSR Rule was challenged in *Alabama Power Co. v. Costle*, 636 F.2d 323 (D.C. Cir. 1979) (per curiam). Petitioners challenged EPA's use of the 100 and 250 ton per year major source thresholds to define what constitutes a "major" modification triggering PSD. *Id.* at 399. The court found that these thresholds were unlawful because the "the term 'modification' is nowhere limited to physical changes exceeding a certain magnitude," and therefore EPA's authority to exempt some emission increases from PSD applicability is limited to *de minimis* increases, which EPA had not shown the major source threshold levels to be. *Id.* at 400. However, no party challenged the 1978 NSR Rule's general approach of comparing a source's maximum emissions before and after a project. The court also found that the 1978 NSR Rule's applicability test was unlawful because it did not account for the *net* effect of a project on emissions by using a "'bubble concept'" to assess emission increases. *Id.* at 401-03. The D.C. Circuit interpreted the CAA to require that changes that "do not produce a net increase in any pollutant … are not 'modifications' at all" for purposes of NSR. *Id.* at 401.

In response to the court's decision in *Alabama Power*, EPA promulgated the 1980 NSR Rule. 45 Fed. Reg. 52,676 (Aug. 7, 1980). The Agency amended its regulations to allow use of a "'bubble' concept," defining "major modification" to mean "any physical change in or change in the method of operation of a major stationary source that would result in a significant *net emissions increase*" of a regulated pollutant. *Id.* at 52,735 (emphasis added). And EPA again shifted the focus of its emissions increase inquiry, this time from the 1978 NSR Rule's "potential-to-potential" analysis of pre- and post-change annual emissions to an "actual-to-actual" test. The 1980 NSR Rule defined a "net emissions increase" in terms of the source's "actual emissions," *id.* at 52,736, which were generally calculated based on the unit's average annual emissions during a representative two-year baseline, unless the unit "has not begun normal operations" as of the relevant time period, in which case actual emissions "shall equal the potential to emit of the unit." *Id.* at 52,737. In applicability determinations during the early years of the 1980 NSR Rule's implementation, EPA interpreted the rule to provide that for existing units, only changes that would cause an increase in the unit's maximum hourly emissions rate could trigger NSR because any emissions increase due to greater utilization would be categorically excluded. *See Envtl. Def. v. Duke Energy Corp.*, 549 U.S. 561, 580-81

(2007) (discussing Reich determinations).[41] Although the Supreme Court would later hold these determinations were inconsistent with the text of the 1980 NSR Rule, *id.*, they reflected the Agency's understanding of what constitutes a modification under NSR , and there is no instance in which anyone disagreed or challenged these determinations as inconsistent with the Act, just as no one challenged the 1978 rules' potential-to-potential emissions increase test. Notably also, the Supreme Court nowhere in its *Duke Energy* decision suggested that a consistent definition of "modification" in NSR and NSPS would be unlawful. Nor could it, as the two programs share a common statutory definition of "modification." CAA § 111(a)(4). Rather, the Court observed that a regulatory approach requiring that "before a project can become a 'major modification' under the PSD regulations, 40 CFR § 51.166(b)(2)(i) (1987), it must meet the definition of 'modification' under the NSPS regulations, § 60.14(a) … sounds right," but it found such a reading nonetheless unsupported by "the language of the [1980 NSR] regulations." *Id.* at 581 n.8.

In 1988, for the first time, EPA began to assert that *all* non-routine physical changes to existing sources cause annual emissions to increase and require pre-change actual annual emissions to be compared to post-change potential annual emissions. The Agency's rationale was that where changes are made to an existing emissions unit, the post-change unit has been "modified" and thus had "not begun normal operations" representing its new state—meaning that its "actual emissions" for the post-change period must be calculated as its potential to emit. The First Circuit upheld this approach as applied to the wholesale replacement of an existing unit in *Puerto Rican Cement Co. v. EPA*, 889 F.2d 292 (1st Cir. 1989). Some at EPA at the time claimed the *Puerto Rican Cement* decision to be a "ringing endorsement" of the view that plant alterations that "provide an economic incentive

[41] The district court's decision in *Duke Energy* (the affirmance of which was later reversed by the Supreme Court) contains a more complete description of EPA's position in the early 1980s, as reflected in the Reich determinations. *See United States v. Duke Energy Corp.*, 278 F. Supp. 2d 619, 629, 641-42 (M.D.N.C. 2003), *aff'd on other grounds*, 411 F.3d 539 (4th Cir. 2005), *vacated sub nom. Envtl. Def. v. Duke Energy Corp.*, 549 U.S. 561 (2007).

to increase production" trigger NSR permitting requirements. *See* Memorandum from Gregory B. Foote, Attorney, Air & Radiation Div., EPA, to William G. Rosenberg, Assistant Adm'r for Air & Radiation, EPA, through Alan W. Eckert, Assoc. Gen. Counsel, Air & Radiation Div., EPA, at 1, 3 (Nov. 24, 1989), https://www.epa.gov/sites/production/files/2015-07/documents/apealdec.pdf. They urged EPA to apply this "recent activist posture on PSD issues," *id.* at 3, to existing units, regardless of whether such units had begun normal operations.

However, just a few months later the Seventh Circuit rejected EPA's actual-to-potential reading of the 1980 NSR Rule as applied to the renovation of an existing electric utility steam generating unit. *Wis. Elec. Power Co. v. Reilly*, 893 F.2d 901 (7th Cir. 1990) ("*WEPCo*"). The court found there was "no support in the regulations for the EPA's decision wholly to disregard past operating conditions at the plant" when estimating post-project emissions for a unit that has already been in operation and found EPA's logic—which had to assume the plant was "modified" in order to justify using the "potential to emit" approach that then showed that a "major modification" had occurred—to be circular. *Id.* at 917.

The "economic incentive to increase production" view of NSR applicability and the NSPS baseline approved in the *WEPCo* case – "just before" the renovation project, threatened major disruption in the electric utility sector, at a time when Congress was about to legislate an innovative and comprehensive cap-and-trade Acid Rain program to drastically reduce SO_2 and NOx emissions from existing EGUs. Congress considered remedial legislation to address the *WEPCo* case issues, but ultimately opted for an exhortation to EPA to promptly fix those problems with changes to the NSPS and NSR applicability rules. *See* Conference Report to Accompany S. 1630, Report No. 101-952 (Oct. 26, 1990), Joint Explanatory Statement of the Committee of Conference, at 344 , *reprinted in* Env't & Nat. Res. Policy Div. of the Congressional Research Serv., 1 Legislative History of the Clean Air Act Amendments of 1990, at 1794(1998) ("The deletion of most provisions relating to the

WEPCO decision is not intended to affect or prejudice in any way the issues or resolution of the WEPCO matter. At the same time, the conferees urge a quick resolution of the WEPCO matter by EPA as appropriate.")

In response to the *WEPCo* case and the urging from Congress, in 1992 EPA promulgated a new "emissions increase" test only available for assessing modification of existing electric utility steam generating units. 57 Fed. Reg. 32,314 (July 21, 1992). This test, known as the "*WEPCo* Rule," established an "actual-to-projected-actual" emissions increase test for these units, in which post-project emissions would be calculated as "the average rate, in tons per year, at which the source is projected to emit a pollutant for the two-year period" after the project. *Id.* at 32,336-37. The *WEPCo* Rule also accounted for the statutory element of causation in the actual-to-projected-actual test by requiring that the calculated emission increase exclude any part of the post-project emissions that "could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to" the project. *Id.* Instead of looking at maximum boiler operation "just before" the project for purposes of NSPS hourly emission rate comparisons, EPA adopted a five-year lookback baseline. *Id.* at 32,330-31. EPA also stressed than under this test only when an efficiency improvement, and not demand growth, was the "predominant cause" of increased emissions could it be relevant to NSR applicability. *Id.* at 32,327. For non-electric utility steam generating units, EPA retained the 1980 NSR Rule's applicability test.

Most recently, EPA in 2002 amended the regulations to make the *WEPCo* Rule's actual-to-projected-actual emissions increase test available for all types of existing sources, rather than just electric utility steam generating units. 67 Fed. Reg. 80,186 (Dec. 31, 2002) ("2002 NSR Reform Rule"). The 2002 NSR Reform Rule also extended the baseline period used for analyzing pre-project emissions at non-electric utility steam generating units to 10 years. 40 C.F.R. § 52.21(b)(48)(ii).

These numerous shifts in EPA's methodology for determining when a "modification" or "major modification" has occurred under the NSR program show the broad discretion EPA has to define what constitutes an increase in emissions. There is nothing inevitable or immutable about EPA's current approach. Indeed, at various times in the past—including immediately before and after Congress created the statutory NSR program—that test has focused on changes in a source's maximum hourly emissions, similar to the approach proposed here.

XV. EPA's Proposal to Adopt an Hourly Emissions Rate Increase Test Is Consistent with the CAA and Judicial Precedent.

EPA's proposed approach of adopting an emission rate increase test for modifications based on changes in a unit's maximum hourly emissions is well within the Agency's statutory authority. As the D.C. Circuit has repeatedly recognized, the CAA entrusts EPA with broad discretion to give meaning to the term "increases," including the time frame over which those increases are measured. The only contextual limitation on that discretion that the courts have recognized is that modification must be based on increases in actual emissions, and both EPA's proposed maximum achieved and maximum achievable approaches capture actual emissions. And nothing in the CAA requires EPA to focus on annual emissions rather than hourly (or some other time frame) in evaluating emissions increases.

A. The CAA Does Not Specify How Emission Increases Should Be Determined, Leaving EPA With Broad Discretion.

Both the PSD and Nonattainment NSR provisions define "modification" by cross reference to section 111, which provides that "modification" means "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." CAA § 111(a)(4). As the D.C. Circuit has recognized, this language is broad, leaving EPA with wide latitude to give meaning to the term "modification" and to determine what constitutes an increase in emissions.

In *New York v. EPA*, 413 F.3d 3 (D.C. Cir. 2005) (per curiam) ("*New York I*"), the D.C. Circuit considered challenges to EPA's 2002 NSR Reform Rule. Addressing challenges to EPA's 10-year baseline period for non-electric steam generating units, the court held that "[i]n enacting the NSR program, Congress did not specify how to calculate 'increases' in emissions, leaving EPA to fill in that gap while balancing the economic and environmental goals of the statute." *Id.* at 27; *see also id.* at 22 (noting CAA "is silent on how to calculate … 'increases in emissions" for the purposes of the modification analysis). The court recognized that "[d]ifferent interpretations of the term 'increases' may have different environmental and economic consequences, and in administering the NSR program and filling in the gaps left by Congress, EPA has the authority to choose an interpretation that balances those consequences." *Id.* at 23-24. In making that choice EPA may consider a wide range of factors, from the Agency's "extensive experience and expertise" on technical matters to "the incumbent administration's view of wise policy." *Id.* at 24.[42]

The court in *New York I* held that the CAA gave EPA discretion to extend the baseline period for non-electric utility steam generating units to 10 years. The court found EPA's choice "'fulfills the statutory goal of balancing economic growth with the need to protect air quality.'" *Id.* (citation omitted). The D.C. Circuit accepted EPA's explanation that the selected baseline period

[42] The court's recognition of the important role policy preferences have in defining "modification" is significant, given that courts have routinely found that a new administration's desire to give effect to new and different policies is a sufficient justification for an agency to amend its regulations. *See FCC v. Fox Television Stations, Inc.* , 556 U.S. 502, 515 (2009) (holding where agency changes rule due to changed policy preferences, "it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency *believes* it to be better") (emphasis in original); *Motor Vehicle Mfrs. Ass'n of the United States, Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 59 (1983) (Rehnquist, J , concurring in part, dissenting in part) ("A change in administration brought about by the people casting their votes is a perfectly reasonable basis for an executive agency's reappraisal of the costs and benefits of its programs and regulations. ").

would promote economic growth and administrative efficiency by, *inter alia*, making it easier for sources to preserve unused capacity and reducing the resources consumed by disputes over selecting a representative baseline period. *Id.* The court also deferred to EPA's "predictive judgment" that extending the baseline period would not adversely affect the environment and would protect air quality by eliminating disincentives to "mak[ing] physical or operational changes that improve efficiency and reduce emissions rates." *Id.* at 24, 37.

In 2006, the D.C. Circuit again confirmed EPA's discretion under the CAA to give meaning to the emissions increase criterion for modification. *New York v. EPA*, 443 F.3d 880 (D.C. Cir. 2006) ("*New York II*"). *New York II* concerned a 2003 NSR rule that would have defined what projects should be considered RMRR that do not trigger NSR. *Id.* at 883. While that case focused on the meaning of the term "any physical change" in section 111(a)(4), it analyzed that language by comparing it with the term "emissions increases." The court highlighted EPA's discretion to define what emission increases constitute "modification" in order to contrast it with Congress's unambiguous direction as to what kind of physical changes can trigger NSR. *Id.* at 888-89. According to the D.C. Circuit, while Congress spoke clearly in stating that "any physical change" can trigger NSR, its use of the ambiguous term "increases" "necessitated further definition regarding *rate* and *measurement* for the term to have any contextual meaning." *Id.* (emphases added)

Thus, EPA's wide latitude to define what emission increases are relevant for purposes of the NSR modification analysis is well established. As discussed below, the applicability tests proposed here are within EPA's authority under the statute.

B. EPA's Proposed Alternatives Measure "Actual" Emissions.

While acknowledging the Agency's discretion to define what constitutes an "emissions increase," the court in *New York I* did recognize one contextual constraint on that discretion: the D.C. Circuit held that "the plain language of the CAA indicates that Congress intended to apply

NSR to changes that increase *actual* emissions instead of *potential or allowable* emissions." 413 F.3d at 40 (emphases added). According to the court, section 111(a)(4)'s reference to "'the *amount* of any air pollutant *emitted* by [the] source' plainly refers to actual emissions," since Congress used different language when it referred to potential or allowable emissions. *Id.*

EPA's proposed "maximum achieved" and "maximum achievable" hourly emission increase tests satisfy this requirement because they both reflect measures of "actual" emissions. The "maximum achieved" hourly emissions test (however determined, including using a statistical analysis or a "once in five years" test, as appears to be the case in alternatives 1 and 2 of the proposed regulations) would clearly reflect "actual" emissions because it is based on comparing records of the amount the source actually emitted and will emit before and after the project. Indeed, a "maximum achieved" test is the same—only the averaging period is different—as the current actual-to-projected-actual emissions increase test for major modification, which was upheld by the D.C. Circuit in *New York I*. Under the actual-to-projected-actual test, the analysis is based on comparing: (1) the "average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within" the baseline period; with (2) "the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project." 40 C.F.R. § 52.21(a)(2)(iv)(c), (b)(41), (b)(48). As a practical matter, the actual-to-projected-actual test is itself a "maximum achieved" emissions increase test (using annual rather than hourly emissions), given that source owners will typically select the highest available baseline period to reflect pre-project emissions.

The proposed "maximum achievable" test is also based on "actual" emissions. As proposed, the "maximum achievable" approach would require that pre- and post-project emissions be determined according to the same methodology used for the NSPS program, codified at 40 C.F.R.

§ 60.14(b). *See* 83 Fed. Reg. at 44,800, 44,802, Proposed 40 C.F.R. §§ 51.167(f)(1) Alternative 3, 52.25(f)(1) Alternative 3. That methodology, in turn, generally requires that pre- and post-project emissions be determined using emission factors under certain circumstances or using actual emission measurements from continuous monitor data or manual emission tests performed under the same, representative conditions.[43] 40 C.F.R. § 60.14(b)(2). The source owner may not use emission factors to calculate pre- and post-change emissions unless they are capable of demonstrating that emissions resulting from the change will either clearly increase or clearly not increase. *Id.* § 60.14(b)(1). Thus, implementation of the "maximum achievable" test is based on analysis of the unit's actual emissions.

Further, the "maximum achievable" test is clearly one based on actual emissions because it mirrors the way modifications have been assessed in the NSPS program—which is based on the same statutory definition the D.C. Circuit held "plainly refers to actual emissions"—since its inception. Indeed, in promulgating the NSPS test in the 1975 rulemaking, EPA explained:

> The proposed amended definition of "modification" also includes a new phrase "… emitted into the atmosphere …." The new phrase clarifies that for an existing facility to undergo a modification there must be an increase in *actual emissions*. … [T]he proposed definition of modification is limited to increases in *actual emissions* [not potential emissions] in keeping with the intent of section 111 of controlling facilities only when they constitute a new source of emission.

39 Fed. Reg. at 36,946 (emphases added).

C. Nothing in the Act Precludes EPA From Determining Emissions Increases for "Modification" in Terms of Hourly Emissions. (Comment C-65)

EPA's authority to define what "emissions increases" may constitute modifications includes the discretion to base its test on hourly emissions increases. As noted above, the D.C. Circuit has recognized that "[i]n enacting the NSR program, Congress did not specify how to calculate 'increases' in emissions, leaving EPA to fill in that gap while balancing the economic and

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[43] The WEPCo Rule extended the baseline for that test for EGUs to five years. *See* 40 C.F.R. § 60.14(h).

environmental goals of the statute." *Id.* at 27. Adopting an hourly emissions increase test for modification is a permissible interpretation of the statute that will promote the CAA's environmental and economic goals.

For one, the NSPS program—which is based on the same statutory definition—has defined modifications in terms of hourly emission rates since its inception. Likewise, EPA's regulatory PSD program focused on hourly emission increases. When Congress enacted the statutory PSD and Nonattainment NSR programs in the 1977 CAA Amendments, it was fully aware of the interpretation EPA had given to "modification" in both its PSD and NSPS regulations. And rather than include provisions in the 1977 Amendments rejecting that approach for NSR modifications, Congress instead strengthened the links between the two programs by defining "modification" for NSR purposes via cross-reference to section 111. CAA §§ 169(2)(C), 171(4). In fact, Congress even allowed the 1974 PSD Rule's modification provisions to remain in effect temporarily pending promulgation of new implementation plans, suggesting that it did not consider the NSPS modification test to be inconsistent with the new statutory NSR provisions. *See id.* § 168. In short, by not disavowing those programs' existing regulatory gloss and instead tying them together via a common definition of "modification," Congress at least suggested that it would be *permissible* for EPA to adopt an hourly emissions increase test for purposes of the NSR program. And Congress certainly did not preclude it. Indeed, it would be a strange way to preclude EPA from using the same emissions increase test for modification under NSR and NSPS by explicitly cross-referencing the NSPS definition in the newly-enacted NSR provisions.

Because the hourly emissions increase tests proposed here are similar to options presented in previous NSR proposals in 2005 and 2007, EPA's proposed alternatives have already been the subject of public comment. *See* 70 Fed. Reg. 61,081 (Oct. 20, 2005) ("2005 Proposal"); 72 Fed. Reg. 26,202 (May 8, 2007) ("2007 Proposal"). Some commenters on those proposals opposed EPA's use of an hourly emissions increase test, arguing that the Agency lacks authority under the CAA to depart from its present focus on annual emissions in the modification analysis. However, none of the arguments presented in those comments have merit.

At the outset, UARG notes that the D.C. Circuit has rejected previous efforts to impose temporal constraints on how EPA may calculate emission increases. In *New York I*, petitioners objected to EPA's decision to establish a pre-change baseline period for existing non-electric utility steam generating units that constitutes "'any consecutive 24-month period selected by the [source] within the 10-year period immediately preceding [the project].'" 413 F.3d at 22 (citation omitted). The petitioners argued that the modification analysis must compare emissions immediately before and after the project. *Id.* at 22-23. Otherwise, they said, a 10-year baseline would allow massive increases in actual annual emissions from the period immediately before the project to that immediately after the project. But the court disagreed and held that the term "increases" is not tied to any particular time frame, thus leaving EPA the discretion to determine what types of emission increases to consider. *Id.* at 23.

None of the previous criticisms submitted by commenters on the 2005 and 2007 Proposals suggests that a modification test based on hourly emission rates would be unreasonable. Some commenters opposed the use of an hourly emissions test by arguing that an hourly emissions analysis is *per se* incapable of reflecting "actual" emissions as required by *New York I*, since it would fail to account for "actual" increases in annual emissions that could result from increased utilization of a unit. *See, e.g.*, American Lung Association et al., Comments on EPA's 2005 Proposal at 3 (Feb. 17, 2006), EPA-HQ-OAR-2005-0163-0165 ("2005 Proposal Public Health Comments"); American Lung Association et al., Comments on EPA's 2007 Proposal at 12 (Aug. 8, 2007), EPA-HQ-OAR-2005-0163-0339 ("2007 Proposal Public Health Comments"). However, this argument is based on a logical fallacy: it simply assumes that annual emissions are the only relevant "actual" emissions for purposes of the NSR program and the CAA generally. In fact, EPA has adopted NAAQS expressed in multiple averaging periods (1-hour, 3-hour, 8-hour, etc.) including hourly. No matter what averaging rate EPA selects to define an emissions increase for what constitutes a "modification" under § 111(a)(4), that rate will necessarily allow emissions averaged over a different period (whether shorter or longer) to increase. As the D.C. Circuit has repeatedly noted, "[i]n enacting the NSR program, Congress did not specify how to calculate 'increases' in emissions, leaving EPA to fill in that gap while balancing the economic and environmental goals of the statute." *New York I,* 413 F.3d at 27. Whatever rate EPA selects to define modification will have *both* economic and environmental impacts (among the latter, the issue discussed above regarding averaging periods); all EPA must do is to consider both and explain how it balanced them in selecting the rate. That is, after all, the very premise of *Chevron*, which upheld a revision to the nonattainment NSR rules that resulted in more projects not being subject to review. *Chevron, U.S.A., Inc. v. Nat. Res. Def. Council, Inc.*, 467 U.S. 837 (1984).

Here, EPA has done such a balancing. EPA has explained that a maximum hourly emission rate test will encourage projects that maintain and improve efficiency, safety, and reliability. Each is an important economic good. They are also good for the environment: encouraging these projects and eliminating the cost of potential NSR applicability means that more of these projects can be done under the Proposed ACE Rule. The overall effect of these projects is an overall *reduction* in CO_2 emissions, not an increase, on whatever timeframe is considered, including annual. *See* ACE RIA at ES-8 to ES-10 Tbls. ES-5, ES-6, ES-7, and ES-8 (reporting lower total CO_2, SO_2, and NO_x emissions from the electricity sector for the Proposed ACE Rule with NSR reform case – 4.5% HRI Scenario at $100/kW – than the no CPP case and the Proposed ACE Rule with no NSR reform case – 2% HRI Scenario at $50/kW). Moreover, EPA in the 2007 Proposal undertook modeling to evaluate the proposed rule, which was largely similar to this Proposal. EPA's modeling concluded that overall, emissions of other pollutants would not increase. 72 Fed. Reg. at 26,206-13. EPA's 2007 modeling showed that the major reasons for this conclusion are the constraints established by other programs applicable under the CAA, most notably the Clean Air Interstate ("CAIR") and CAMR. *Id.* at 26,208. Since then, CAIR has been replaced with a more stringent program, CSAPR. And CAMR has been replaced with a more stringent program, MATS. Other programs that constrain overall emissions have taken effect, such as the Regional Haze program and some revised NAAQS. Therefore, the results of the modeling EPA conducted in 2007 are more strongly applicable now.

In addition, in the utility industry, generation sources are typically dispatched based on their cost of production. If one coal unit is dispatched more than it was in the past, it is generally displacing generation from a more costly – and likely less efficient – coal unit. Less efficient units typically have higher emissions rates[44]; therefore, overall, emissions (including on an annual basis) go down when a more efficient unit displaces a less efficient unit.

In short, EPA has balanced the economic impact of the proposed NSR revisions—a net economic positive from encouraging projects that maintain and improve efficiency, safety, and reliability; a net environmental positive from encouraging projects to meet the requirements of the ACE rule, and lower overall emissions; and an alleged negative environmental from allowing some individual units to run more hours. EPA can easily conclude that the net positives outweigh the alleged negative. Especially where there are other programs that are designed to protect air quality at all locations, including the SIP requirements to protect the NAAQS and the increments. And where, absent an intervening project, nothing prevents a unit from increasing its hours of operation or

[44] Under the current and expected market conditions, a coal unit in not likely to become so much more efficient as to displace a gas unit. EPA has previously confirmed these industry trends. *See* 83 Fed. Reg. at 44,750-51.

overall rate of production, *see* 40 C.F.R. § 52.21(b)(2)(iii)(*f*), regardless of any associated increase in actual emissions.

Opponents of the 2005 and 2007 Proposals also argued that other CAA provisions governing the PSD and Nonattainment NSR program indicate that the modification analysis for NSR must be limited to changes in annual emissions. *See* 2005 Proposal Public Health Comments at 9-10; North Carolina Environmental Defense et al., Comments on EPA's 2005 Proposal at 5-6 (Feb. 17, 2006), EPA-HQ-OAR-2005-0163-0134 ("2005 Proposal ENGO Comments"); New York Attorney General Eliot Spitzer et al., Comments on EPA's 2005 Proposal at 31-32 (Feb. 16, 2006), EPA-HQ-OAR-2005-0163-0141. In particular, they cited CAA sections 169(1) (establishing emission thresholds for "major emitting facilities" in terms of "tons per year"), 165(b) (providing that sources subject to PSD review need not go through an increments analysis if their emissions are below a *de minimis* "tons per year" threshold), and 173(c)(1) (requiring offsets in nonattainment areas to cover the "total tonnage" of a new or modified source's increased emissions). *See id.* But nothing in these isolated provisions bears any meaningful relationship to how an emission increase must be determined under section 111(a)(4). Indeed, the D.C. Circuit in *Alabama Power* has already rejected EPA's previous effort to tie the modification analysis to the major source thresholds in section 169(1). 636 F.2d at 399-400. Sections 165(b) and 173(c)(1) pertain to what requirements apply to a source once it has been deemed to be modified, but they do not offer any insight as to how modification must be determined in the first place. In fact, if anything, the explicit references to "tons per year" in the cited statutory provisions demonstrates that Congress knew how to specify a particular time frame or unit of measurement when it wanted to, and it chose not to do so in defining "modification."

In a related argument, commenters argued that when Congress adopted the 1990 CAA Amendments, it did so against the backdrop of EPA's 1980 NSR Rule and its modification test, thus baking that rule's focus on annual emissions into the new statutory provisions. 2007 Proposal Public Health Comments at 34. Their primary example was CAA section 182(c)(6), which provides that no increase in volatile organic compound emissions resulting from a project in a serious ozone nonattainment area shall be considered "*de minimis*" for purposes of Nonattainment NSR applicability unless it "does not exceed 25 tons … over any period of 5 consecutive calendar years." But as with the provisions cited above, section 182(c)(6) has no bearing on how EPA may decide what constitutes a "modification" for purposes of section 111(a)(4). Section 182(c)(6) deals only with how EPA may exercise its authority to exclude from NSR requirements "*de minimis*" emission increases that would *otherwise* qualify as "modifications" under whatever metric EPA uses. There is nothing inconsistent about identifying modifications based on changes in hourly emissions while only excluding as "*de minimis*" those projects that fall below certain annual emission thresholds: indeed, that is precisely the approach EPA has proposed here, since the new hourly emissions increase test EPA proposes would merely be a first step before proceeding to use the currently applicable analysis of significant emissions increases and significant net emissions increases. In addition, UARG notes that section 182(c)(6) expresses its *de minimis* threshold in terms of a five-year sum, demonstrating that the NSR program can accommodate different provisions using different temporal frameworks.

Finally, commenters argued that at least for PSD purposes, the modification analysis must be based on annual emissions because of the statutory connection between the PSD program's preconstruction permitting requirements and its program for protection of air quality increments. *See* 2005 Proposal Public Health Comments at 10-12; 2007 Proposal Public Health Comments at 34-37; 2005 Proposal ENGO Comments at 3. They cite the D.C. Circuit's decision in *Alabama Power*, which observed that the "preconstruction review and permit process required for new or modified major emitting facilities" is "the principal mechanism for monitoring the consumption of allowable increments." 636 F.2d at 362. According to these commenters, EPA has "no authority to define the NSR trigger in a way that prevents the PSD permitting program from preventing PSD increment violations," and an hourly emissions increase test would do that because it could allow projects that increase annual emissions to proceed without preconstruction review. 2007 Proposal Public Health Comments at 42.

But while the preconstruction permitting requirements are connected to the PSD program's increment provisions, that connection does not constrain EPA's discretion in determining what types of emission increases constitute modification. For one, the CAA does not require that all emissions increases that might consume PSD increment undergo preconstruction review and permitting, as the D.C. Circuit recognized in *Alabama Power*. 636 F.2d at 362. A "modification" for NSR purposes does not include emissions increases that result from a source utilizing formerly unused capacity without making any physical or method of operation change. Thus, such emissions increases are not subject to preconstruction review. Yet Congress chose to define PSD increment consumption in relation to baseline air quality without providing any carve-out for unused capacity at existing sources. CAA § 169(4); *see also* 2007 Proposal Public Health Comments at 81-82 (discussing Congress's rejection of approach that would have defined baseline concentrations '"on the basis of plant capacity in existence"'). The same is true for emissions increases that may occur as a result of switching the fuel burned in the unit to another fuel that is allowed under the facility's permit but that has a higher emissions rate (for example, a coal that has slightly more sulfur or ash content). As a result, the PSD program already allows some emission increases to occur that consume applicable PSD increments without undergoing preconstruction permit review. In point of fact, actual concentrations of pollutants with PSD increments have persistently and substantially declined, not increased, over the years, and they will continue to decline for the foreseeable future.

Indeed, while commenters opposing the hourly test cited *Alabama Power* to argue that the PSD increment program depends heavily on subjecting emissions increases to preconstruction permit review, the court in *Alabama Power* actually acknowledged that the two programs are not co-extensive. The D.C. Circuit observed that while the PSD permitting process may be the "principal mechanism for monitoring the consumption of allowable increments," it is not "the exclusive mechanism." 636 F.2d at 362. Instead, many types of emissions increases that could consume PSD increment are not covered by the PSD permitting program:

> Significant deterioration may occur due to increased emissions from unregulated minor sources and major emitting facilities grandfathered out of the permit process, due to the use of different models to calculate increment consumption, due to the discovery through monitoring that limitations inadvertently have been exceeded, due to redesignation of an area to a more restrictive class, or due to allocation through administrative error of too many permits.

Id. The CAA already provides a method to protect against excessive increment consumption where an emission increase is not subject to review under the PSD permitting process: states have an independent obligation under the Act to "assur[e] that maximum allowable increases over baseline concentrations of, and maximum allowable concentrations of, [applicable] pollutant[s] shall not be exceeded." CAA § 163(a). Therefore, EPA is not required to tailor its modification test to capture all emission increases that might consume PSD increment.

In any event, the commenters' argument with respect to PSD increments reflects the same logical fallacy discussed above, in that it assumes only annual increments are relevant. PSD increments are not expressed only in terms of annual averages. They are also expressed in terms of 24-hour and 3-hour maximum concentrations. *Id.* § 163(b). These short-term increments may actually be *better* protected by a modification test that accounts for changes in hourly emissions than one based on annual emissions alone.

XVI. UARG Supports Adopting the Hourly Emissions Rate Increase Test as a Prerequisite to the Present "Significant Net Emissions Increase" Test.

EPA has proposed to pair the new hourly emissions increase test for modifications with its current annual emissions increase test for major modifications. 83 Fed. Reg. at 44,780; *id.* at 44,798 & 44,801, Proposed 40 C.F.R. §§ 51.167(c) & 52.25(c). The hourly emissions increase test would become "Step 2" of a four-step NSR applicability analysis for existing EGUs. *Id.* at 44,780. UARG strongly supports retaining the current "significant net emissions increase test" as a step in the NSR applicability inquiry, using the hourly emissions increase test as a prerequisite to determine whether a physical or method of operation change constitutes a "modification" before proceeding to determine whether it is a "major modification" using the currently applicable approach.

The Supreme Court has suggested that this tiered approach is likely an appropriate reading of the CAA. In *Environmental Defense v. Duke Energy Corp.*, 549 U.S. 561 (2007), the Court considered whether the 1980 NSR Rule's definition of "major modification" must be read to conform to the NSPS modification test. On that question, the Court concluded that the language of the 1980 NSR Rule "simply cannot be taken to track" the NSPS definition of modification. 549 U.S. at 577. But the Court also addressed the possibility that the two approaches could be read together as "set to subset," such that "before a project can become a 'major modification' under the PSD regulations [i.e., using an annual net emissions increase test], it must meet the definition of 'modification' under the NSPS regulations [i.e., using an hourly emission rate increase test]." *Id.* at 581 n.8 (internal citations omitted). The Court opined that this reading "sounds right," but was not reflected in the regulatory text promulgated in the 1980 rules. *Id.* Here, EPA is proposing to change the regulatory language to explicitly adopt a "set to subset" approach, under which NSR applies only where the project is a "modification" under § 111(a)(4) and also a "major modification" under the preexisting NSR rules.

UARG notes that there are several advantages to preserving the current "significant net emissions increase test" as a subsequent step after the new hourly emissions increase test. First, it minimizes the overall regulatory changes in this rulemaking, reducing potential disruption. Second, and more importantly, the concepts of "significance" and "netting" in the NSR context are long-standing and have been recognized as implementing sound policy. And finally, EPA's NSR applicability test would likely be legally vulnerable if it eliminated consideration of net changes in emissions. In *Alabama Power*, the D.C. Circuit held that "[w]here there is no net increase from contemporaneous changes within a source, … PSD review, whether procedural or substantive, cannot apply." 636 F.2d at 403. Retaining the current "major modification" analysis as part of a multi-step process to determine NSR applicability fulfills *Alabama Power*'s mandate to account for net emission changes. While it may be possible to account for net emission changes using an hourly emissions-focused test alone, it would be less disruptive to simply retain the current approach as EPA has proposed to do here.

EPA should clarify, however, how the two tests would apply in circumstances in which a change turns out to be a "modification." The proposed rule logically provides:

> If the change to your electric generating unit (EGU), as defined in § 51.124(q) of this chapter, is a modification according to the procedures of this section, you must determine whether the change is a major modification according to the procedures of the major NSR program that applies in the area in which your EGU is located. That is, you must evaluate your modification according to the requirements set out in the applicable regulations approved pursuant to § 52.21.

83 Fed. Reg. at 44,801, Proposed 40 C.F.R. § 52.25(c). But while this is straightforward if the change *is projected* to result in an increase in the maximum hourly emission rate of the unit (i.e., it is projected to be a "modification" under proposed § 52.25), it is ambiguous if the pre-change projection does not reveal an hourly emission rate increase but that projection turns out to be incorrect and such an increase actually occurs later. To avoid the morass of litigation that has plagued NSR for the last two decades, EPA should explicitly address in the regulations three separate possibilities:

(1) Where the change is determined to be a modification based on pre-change projections, the source should proceed under the existing major NSR rules (e.g., 40 C.F.R. § 52.21) to determine whether the change is also a major modification.

(2) Where the change is determined not to be a modification based on pre-change projections, but then the project later turns out to be a modification based on actual operations and emissions after the change, the source should analyze *actual* annual emissions (not after-the-fact "projections") to determine whether the change also resulted in a significant and net significant increase in average annual emissions, as provided under the major NSR rules. If there was such an increase, then the project should either obtain an NSR permit at that time or otherwise take steps to avoid becoming subject to NSR (e.g., by taking a limit on emissions or operations to avoid a significant net emissions increase going forward). The rule should also make clear that in that situation, if the initial projection of maximum hourly emissions was reasonable, the source did not violate the major NSR rules' pre-project analysis and recordkeeping requirements because the source had reasonably concluded that these rules were not applicable to the change at the time.

(3) Where the change is not a modification under the proposed rules (i.e., it is neither projected nor does it in fact result in an increase in the maximum hourly emission rate of an NSR regulated pollutant), the rules should explicitly provide that such a change does not trigger major NSR.

XVII. If EPA Adopts a "Maximum Achieved" Test, It Must Account for Causation and Revise Its Proposed Approaches for Comparing Pre- and Post-Project Emissions.

Finally, UARG notes that while EPA has the necessary authority to incorporate an hourly emissions increase test into its NSR applicability analysis, in enacting that test EPA must also ensure that the other statutory requirements governing NSR applicability are accounted for. Specifically, EPA must ensure that the statutory element of causation is incorporated into the regulatory language.

Section 111(a)(4) requires that a causal link exist between the "physical change in, or change in the method of operation of, a stationary source" and the increase in emissions from the source in order to qualify as a modification. EPA has recognized this causal element throughout the history of the NSPS and NSR programs. *See* 57 Fed. Reg. at 32,326 ("NSR will not apply unless … there is a causal link between the proposed change and any post-change increase in emissions."); *id.* at 32,327 (Including provisions into NSR rules that explicitly implement causal requirement "merely incorporates … a requirement of the pre-existing statutory and regulatory scheme."); 67 Fed. Reg. at 80,203 (same); *see also New York I*, 413 F.3d at 32-33 (noting with approval EPA's acknowledgment that language of CAA § 111(a)(4) requires "'a causal link between the proposed change and any post-change increase in emissions'") (quoting 67 Fed. Reg. at 80,203).

EPA's proposed "maximum achievable" hourly emissions test adequately accounts for this element of causation. The Proposal incorporates the language of EPA's modification test for the NSPS program under 40 C.F.R. § 60.14(b). That provision allows two approaches for evaluating whether a project would result in an increase in the unit's maximum achievable hourly rate. Under the first approach, the source may use emission factors to calculate pre- and post-change emissions where such factors are capable of demonstrating that emissions resulting from the change will either clearly increase or clearly not increase. *Id.* § 60.14(b)(1). This approach accounts for causation implicitly by ensuring that the project can be expected to increase the unit's hourly emissions rate only if the project results in an increase in a factor that either increases the emission factor itself (i.e., the project increases the lb/mmBtu factor of the unit) or the amount of Btu consumed in the unit (i.e., the maximum mmBtu/hr of the unit). If the project does not affect either of these two factors, it will not increase the unit's maximum hourly emissions rate. Under the second approach, the source may use emission stack tests or CEMS for determining pre- and post-change maximum emissions; in doing so, however, "[a]ll operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs." 40 C.F.R. § 60.14(b)(2). By testing the unit's performance under the same conditions before and after the change, that methodology again isolates the effect of the change in question on the source's emissions, ensuring that any difference in emissions is due to the project, and not to any other operating parameters or extraneous factors.

However, both of the alternative methods EPA has proposed for implementing a "maximum achieved" hourly emissions test fail to account for causation. While the statistical "upper tolerance limit" ("UTL") approach (Alternative 1) and the "one-in-5-years" approach (Alternative 2) use different methods to identify pre-project emissions for comparison, both approaches simply compare those pre-project emission values to post-project values and assume that any increase must have resulted from the project in question. That assumption is simply not true for EGUs (or for any type of source, for that matter).

An EGU may observe—or even expect—higher hourly emissions in the post-project period for a myriad of reasons wholly unrelated to the project. Coal-fired EGUs' emission rates are affected, for example, by variation in coal quality, which includes variation in the coal's moisture content, sulfur content, heat content, ash content, and nitrogen content. Emission rates are also affected by variability in the operation of control technologies, such as electrostatic precipitators, SCRs, and scrubbers. Control technology operations can affect emission rates both on a short-term basis (spikes) and long-term basis (catalyst changes, long-term deterioration and overhauls). Both boiler and control technology operations may be affected by ambient conditions, including cooling tower efficiency, water temperature, atmospheric pressure, ambient temperature, and relative humidity. They may also be affected by conditions that vary over cycles that can last longer than 5 years, such as turbine overhauls undertaken at 7- or 8-year intervals.

Further, an EGU's hourly emissions may appear to be higher simply due to normal variability in its emission measurements. As discussed in Section III.B.3 above, despite application of stringent quality assurance and quality control requirements, there are many potential sources of variability in Part 75 (and other) measurements collected at each EGU that are unrelated to any actual changes in the unit's emissions. Indeed, it is a basic scientific fact that any measurement is subject to some degree of inherent uncertainty. Thus, even if a unit's emissions remained perfectly constant before and after a project, one would expect to observe fluctuation in the measured emission values simply due to variability in the measurement techniques applied.

The problem with the proposed "maximum achieved" tests can be illustrated in the context of a hypothetical fluctuation in the sulfur content of a plant's coal. It is well-established that the SO_2 emission rate of a boiler is essentially directly related to the sulfur content of the coal being burned in the boiler. Sulfur content can vary, however, even within the same type of coal mined from the same mine. After five or more years of operation with coal from one mine, the utility may, for whatever reason, start receiving coal from another mine or even from a different seam at the same mine. Even a small increase in the coal's sulfur content would likely result in a commensurate increase in the EGU's SO_2 emission rate, all else equal. If the utility happens to have undertaken a completely unrelated project in the meantime that constitutes a physical or operational change, application of EPA's "maximum achieved" tests – as proposed – would likely conclude that the project constitutes a modification, even though the change in SO_2 emissions was clearly caused by the change in sulfur content and had nothing to do with the project.

UARG supports the NSPS maximum achievable hourly rate test (alternative 3) because it is well established; it compares actual hourly emissions at actual operating maximum levels before and after the project and implicitly accounts for causation, as discussed earlier. But if EPA is inclined to adopt a maximum achieved hourly rate test, there are at least two basic ways in which EPA can incorporate the necessary causal link into its proposed "maximum achieved" hourly emissions tests. First, EPA could require a comparison of the maximum hourly emissions achieved before and after the project in question under the same representative conditions. This approach would be similar to the methodologies set forth in 40 C.F.R. § 60.14(b), thereby isolating the effect of the project itself. Second, in evaluating actual emission measurements before and after the project, EPA must require that the comparison account for causation (for example, by subtracting from the unit's actual post-project maximum hourly emissions any increases that are caused by factors unrelated to the project). UARG suggests that the rules should include both of these approaches.

The first approach is easier to implement and is in any event needed to guide the pre-project analysis for a project. For example, even if a source expects the sulfur content of the coal may increase slightly after the project for reasons unrelated to the project, in evaluating whether the project will increase the unit's maximum achieved hourly emissions, the source should do the analysis under the same conditions (i.e., assume the same sulfur content before and after the project). Alternatively, the source could conclude that the project will not increase the unit's maximum achieved hourly rate if the project meets two conditions: (1) it will not increase the lb/mmBtu emission factor for the pollutant in question; and (2) it will not increase the maximum achieved mmBtu/hr of the unit. This first approach also must be included in the rule for another reason: it is essentially the only way one can analyze situations in which individual-unit emissions data are not collected separately, such as where multiple units have a common stack.

Conversely, the second approach should be included in the rule because, even though it may be more complicated, it is necessary to properly evaluate a situation in which one is comparing the maximum hourly emissions rate actually achieved after the project to the maximum hourly emissions rate actually achieved before the project (however these two values are determined). The rules must provide this methodology so that it is possible to determine whether an increase, if any, is caused by the project or is completely coincidental and due to unrelated factors. But also under this second approach, EPA should make clear that where a project meets the two fundamental conditions above (i.e., (1) it will not increase the lb/mmBtu emission factor for the pollutant in question, and (2) it will not increase the maximum achieved mmBtu/hr of the unit), the project cannot be the cause of an actual hourly emissions increase.

In addition to the concerns noted above, UARG believes that EPA's statistical method for assessing "maximum achieved" hourly emissions (Alternative 1) suffers from several fatal flaws that make it impossible for that test to properly account for causation. The proposed UTL approach is prone to false positives that could trigger NSR for units even where their real world emissions are exactly the same before and after a project.

In the first place, according to EPA's proposed method, the unit's UTL would be calculated based on hourly emission rates reported in the CEMS during the highest 10 percent of yearly operating hours in the baseline period, sorted by *heat input* rather than *emissions*. 83 Fed. Reg. at 44,799 & 44,801, 40 C.F.R. §§ 51.167(f)(1)(i)(C) Alternative 1 & 52.25(f)(1)(i)(C) Alternative 1. Because a unit's highest emissions do not always correspond to its highest heat input values, this creates the possibility that the unit's UTL will not be calculated based on its highest hourly emission values. Thus, if the unit performs identically in the post-project period to its pre-project operations, some hourly values may exceed the UTL simply by virtue of having not been included in calculating the UTL. That issue could potentially be resolved by sorting the emissions data based on the highest 10% emissions, not on the basis of heat input. For those pollutants that are not directly measured in the CEMS, heat input could possibly be used as a surrogate (assuming there is no change in the emission factors for those pollutants).

More fundamentally, however, the proposed statistical method is flawed because it compares an aggregate statistical measure representing *nearly all* of the unit's pre-project emissions values to the unit's observed performance *during every hour* of operation after the project. This is an apples-to-oranges comparison. In the 2007 Proposal, EPA explained that based on its calculation methodology, it would expect "with a 99 percent confidence level, 99.9 percent of the hourly emissions rate data to be less than the UTL value." 72 Fed. Reg. at 26,215. Therefore, it follows that one would expect that 0.1 percent of the unit's hourly emissions data would be *equal to or greater than* the UTL value, simply based on the statistical distribution of the data used to calculate the UTL.

For example, for a unit that operates 8,000 hours per year for the five-year period after the project, there will be 40,000 hourly data points. In a perfect statistical world (where the data are normally distributed), the UTL would include only 99.9 percent of those data points, meaning that the remaining 0.1 percent of the points—up to 40 hours—will exceed the UTL. And with real data, which are likely not normally distributed, even more hours will exceed the UTL. Short term measurement error and imprecision compounds the problem. In short, EPA's proposed statistical test is one that units are statistically assured of failing even when hourly emission rates are unaffected by the project in question, due solely to the variability of the data analyzed. That issue could potentially be resolved by acknowledging this fact and, for example, evaluating whether the rule should allow a certain number of exceedances (corresponding to 0.1% of the data)[45] in the post–project period.

In its comments on the 2007 Proposal, UARG included an analysis of actual data from several units in order to gauge the results that the UTL process might yield in practice. Specifically, UARG's consultants analyzed NOx and SO_2 data for several EGU boilers with various combinations of coals and pollution control technologies. UARG, Comments on EPA's 2007 Proposal (Aug. 8, 2007), EPA-HQ-OAR-2005-0163-0319, and Attachment 1, Lowell Smith &

[45] Such an evaluation may well suggest that more than 0.1% exceedances should be expected, and therefore allowed, because real-life EGU data are most often not normally distributed.

Michael Hein, *Analysis of the Upper Tolerance Limit Process Proposed by EPA for Determining the "Maximum Achieved Hourly Emissions Rate" for Electric Generating Units* (Aug. 6, 2007), EPA-HQ-OAR-2005-0163-0139-0307, -0312, -0310, -0311, -0338, -0309, -0308, -0327, -0324, -0323, -0325 (The Comments and Attachment are Attachment I to these comments). They assumed that after a hypothetical physical or operational change occurred in a given year, each boiler would replicate its exact operations and performance—i.e., at the same loads, emissions, hours, etc.—as it did during the five years before the change. In other words, they assumed that the "change" undertaken by the boiler had no effect whatsoever on the unit's emissions profile, hour-by-hour, for the entire five-year period following the change. UARG's analysis showed that the UTL method proposed in this rule is highly prone to false positives, identifying a project as a modification even if there is no actual change in the unit's emissions. Results from one unit, using the same data set to represent both its pre- and post-"change" emissions, found 41 data points exceeding the calculated UTL for NOx and 425 data points exceeding the UTL for SO_2. UARG's analysis also suggests various approaches that would decrease (though not eliminate) the number of false positives. For example, EPA might evaluate whether to base the UTL on a higher confidence level or on a smaller set of the data close to maximum emissions or heat input (i.e., the top 5% or even 1% of the data, instead of 10%). Another possible solution is to evaluate whether the test should compare the UTL for the baseline period to a confidence interval for a set of data in the post-change period. This appears to be an approach that EPA has elsewhere considered under another program.[46] It should be noted, however, that regardless of any improvements to the UTL method EPA includes, if EPA is inclined to adopt a statistical methodology such as that in Alternative 1 (or, for that matter, *any* methodology based on

[46] *See, e.g.*, EPA Office of Resource Conservation and Recovery, *Statistical Analysis of Groundwater Monitoring Data at RCRA Facilities, Unified Guidance*, Pt. IV (March 2009) (discussing the "confidence interval" as a "key statistical procedure" that may be appropriate for comparing a set of data to a standard or a background level).

actual emission measurements before and after a project), EPA must also include provisions that account for causation in order to differentiate between an increase that is caused by the project and an apparent increase that is caused by factors independent from the project.

If EPA is inclined to adopt a methodology based on Alternative 2, EPA must also revise that methodology to recognize the inherent variability of emissions and heat input measurements. Alternative 2 is very simple: compare the highest recorded measurement before the project to the highest measurement recorded after the project. But that simplicity masks a complex reality. At the outset, we reiterate, the rule must account for causation. That is a given. But even if we assume that the maximum point before the project and the maximum point after the project both occurred under exactly the same conditions, the inherent variability of the measured quantity and its measurement all but assure the two maxima will not be exactly equal. When one is selecting one hour (the maximum hour) among more than 40,000 (five years-worth of hourly measurements), the probability of the maximum of a population of 40,000 points before the project being exactly the same as the maximum of a population of 40,000 points after the project is for all intents and purposes zero. One of these two maxima will be higher than the other, however slightly. The probability of a false positive based on statistical reality is 50 percent! For this reason, it is meaningless to compare these two numbers. One solution potentially could be, however, to compare a population of the top data before the project to an equal population of the top data after the project (e.g., the highest "x" measurements in the five years before the project to the highest "x" measurements in the five years after the project) to determine whether there is a statistically significant difference between the two sets. One possible methodology for undertaking this comparison is the Student's *t* test, which is the test EPA uses in 40 C.F.R. Part 60, Appendix C.

Under all three Alternatives for paragraph (f)(1), EPA proposes to require an exclusion from the required analysis of certain data that would not be representative of emissions that are relevant to identification of an NSR emissions increase. UARG generally agrees with the proposed data exclusions, although EPA likely significantly underestimates the amount of work involved in screening large amounts of historical CEMS data for periods of startup, shutdown, and malfunctions based on regulatory and permit definitions. Many EGUs will be subject to more than one such definition, and most EGUs will not have previously flagged their hourly CEMS data to identify those periods. As a result, EGUs will need flexibility in deciding how to identify those periods and the proposed rule appears to provide that.

With respect to CEMS and predictive emission monitoring system ("PEMS") data, EPA also proposes to require exclusion of "monitoring system out-of-control periods." UARG agrees that these periods should be excluded and agrees with EPA's statement that these are periods "during which the monitoring system fails to meet quality assurance criteria." However, UARG does not agree with EPA's parenthetical example that such periods include "periods of system breakdown, repair, calibration checks, or zero and span adjustments." Relevant rules define "out-of-control" periods in terms of failure to meet a performance specification when conducting a specific quality assurance test. *See, e.g.,* 40 C.F.R. § 75.24, and pt. 75, App. B §§ 2.1.4, 2.2.3(g); 40 C.F.R. pt. 60, App. F, Procedure 1, Quality Assurance Requirements for Gas Continuous Emission Monitoring Systems Used for Compliance Determination. EPA's parenthetical examples are periods during which a monitoring system either would not be operating and would not be recording data (i.e., it was broken down), or would not be recording emissions data because it would have been placed in a separate operating mode, like maintenance (used for repairs and adjustments) or calibration (used when calibration gas is flowing). Those are not periods during which quality assurance tests would be conducted and failed, and they do not fall within the regulatory definitions of "out-of-control" periods. To avoid confusion, EPA should remove the parenthetical.

To address any concern that data from a malfunctioning CEMS or PEMS might be reported and included in an analysis, EPA should list as a separate exclusion periods when the data are "otherwise invalid under an applicable regulation or permit." Such an exclusion also is needed to account for the fact that Part 75 reported data also excludes CEMS values recorded after the expiration of grace period for performing a required quality assurance test, even though the CEMS has not failed any specific quality assurance criterion. *See, e.g.,* 40 C.F.R. pt. 75, App. B, §§ 2.1.5, 2.2.4, 2.3.3. Requiring use of those data in an analysis would impose an obligation to use data that was not reported to EPA (generally, only valid quality-assured data are reported). Alternatively, rather than specify the exclusion of data that are not valid, EPA could promulgate a definition of "valid data" and require that only such data be used in the analysis. EPA has proposed such a definition in § 60.5805a, 83 Fed. Reg. at 44,812, that is based on the Part 75 data validation procedures, although (as discussed above) the definition is not used in proposed Subpart UUUUa.

UARG believes that most EGUs performing analyses with CEMS data will choose to use data recorded and reported under Part 75. Some emissions data reported under Part 75 are affected by what is referred to as a "bias adjustment factor" or BAF. *See, e.g.,* 40 C.F.R. § 75.57(c) and (d). BAFs are a one way (upward) adjustment of recorded hourly emissions data in response to a failure of a statistical test on a relative accuracy test audit data. *Id.* pt. 75, App. A, § 7.6. Because such "bias-adjusted" data would result in a step change in data that could not be attributed to a physical or operational change at an EGU, it should not be used in these data analyses. EPA should specify that where a BAF has been used in the relevant reported emissions or heat input data, the unadjusted data should be used in the analysis. Finally, although it should be obvious that hourly average CEMS values reported using missing data substitution procedures, like those in Part 75, should not be used in the analyses, EPA should explicitly state in the rule that those data also should be excluded.

Doing so would help ensure that the analysis would only be performed using valid, quality assured data for the relevant hours.