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Comments of the American Public Power Association
on EPA's Proposed Rule:

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

Commonly Called the Affordable Clean Energy Rule or ACE Rule

83 Fed. Reg. 44,746 (Aug. 31, 2018)
Docket ID No. EPA-HQ-OAR-2017-0355

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I. Introduction

The American Public Power Association (APPA or Association) appreciates the opportunity to submit 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," commonly referred to as the Affordable Clean Energy Rule (ACE Rule).[1] The Association is the voice of not-for-profit, community-owned utilities that power 2,000 towns and cities nationwide. APPA represents public power before the federal government to protect the interests of the more than 49 million people that public power utilities serve, and the 93,000 people they employ. The Association advocates and advises on electricity policy, technology, trends, training, and operations. Association members strengthen their communities by providing superior service, engaging citizens, and instilling pride in community-owned power. The Association participates on behalf of its members collectively in EPA's rulemakings and other Clean Air Act (CAA or Act) proceedings that affect the interests of public power utilities. For these reasons, APPA has a clear interest in the present rulemaking, as well as the other EPA rulemakings that address carbon dioxide (CO_2) and other greenhouse gas (GHG) emissions under the CAA.

II. Executive Summary

The electric utility sector, including public power, continues to make great strides in reducing CO_2 emissions. The Energy Information Administration notes that CO_2 emissions from the U.S. power sector have declined 28 percent from 2005. EIA has calculated that CO_2 emissions from the electric power sector totaled 1,744 million metric tons in 2017, the lowest

[1] 83 Fed. Reg. 44,746 (Aug. 31, 2018).

level since 1987.[2] This decrease in CO_2 emissions is due in part to public power utilities' investment in low and non-emitting generation technologies, such as solar, wind, hydro, nuclear, and natural gas. The Association agrees that the utility sector needs to continue to reduce CO_2 emissions to address the adverse impacts of climate change. APPA members include utilities actively pursuing reduction of greenhouse gas emissions in coordination with local, state, and regional programs targeting standards exceeding federal proposals such as the ACE Rule. Thus, the Association's comments on the ACE Rule proposal constitute our recommendations for the development of a workable emissions guideline, which will establish procedures to limit CO_2 emissions from existing fossil steam electric generating units (EGUs).

APPA supports EPA's proposed decision to replace the Clean Power Plan (CPP) with emission guidelines for GHG emissions from existing EGUs that adhere to the statutory requirements of CAA section 111(d), thus providing much-needed regulatory certainty for the electric generating sector. APPA previously submitted comments on EPA's proposed repeal of the CPP, 82 Fed. Reg. 48,035 (Oct. 16, 2017), and on EPA's Advance Notice of Proposed Rulemaking soliciting input on this replacement proposal, 82 Fed. Reg. 61,507 (Dec. 28, 2017).[3,4] Those comments are incorporated herein by reference. The Association's comments on the proposed ACE Rule are summarized below.

- The ACE Rule properly reflects the scope and bounds of the Act by identifying the best system of emission reduction (BSER) for coal-fired utility boilers based on measures that

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[2] U.S. Energy Information Administration, *September 2018 U.S. Energy Related Carbon Dioxide Emissions, 2017,* https://www.eia.gov/environment/emissions/carbon/pdf/2017_co2analysis.pdf.

[3] APPA, Comments on EPA's Advance Notice of Proposed Rulemaking on Greenhouse Gas Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 82 Fed. Reg. 61,507 (Dec. 28, 2017) (Feb. 26, 2018), EPA-HQ-OAR-2017-0545-0193 (APPA ANPR Comments).

[4] APPA, Comments on the Repeal of the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 82 Fed. Reg. 48,035 (Oct. 16, 2017) (April 26, 2017), EPA-HQ-OAR-2017-0355-19931(APPA Repeal Comments).

can be applied to or at an individual source and acknowledges states' authority to submit their own plans establishing achievable standards of performance for each source while accounting for unit-specific parameters.

- The ACE Rule appropriately focuses the implementation of heat rate improvements (HRIs) as BSER for existing coal-fired utility boilers. These HRI measures are adequately demonstrated to reduce CO_2 emission rates and, emission standards based on improving or maintaining a unit's efficiency will provide meaningful limits on facilities' emissions.
- The Association supports EPA's proposal to revise certain requirements of the section 111(d) implementing regulations. The proposed changes will facilitate implementation of the ACE Rule by more closely aligning EPA's section 111(d) implementing regulations with the statute and by removing barriers to implementation of heat rate improvement projects.
- The Association supports EPA issuing states guidance describing what comprises a satisfactory state plan. EPA could provide regulatory language in the emission guidelines that identifies the factors state must consider and account for in standard setting without dictating the outcome of that analysis.
- The Association supports allowing states' standards of performance to take many forms. We encourage states to express standard of performance on a gross output-basis.
- The Association supports states' authority to provide flexible compliance options for affected sources to meet their standards of performance. This flexibility allows sources to achieve the Act's goals while minimizing costs and ensuring public power utility customers benefit from affordable, reliable, and sustainable power generation.

- Finally, APPA supports EPA's proposal to revise certain requirements of the Act's New Source Review (NSR) program. The NSR program, as implemented by EPA's enforcement arm, has long been a source of regulatory uncertainty in the industry and has prevented the implementation of projects that could improve reliability, safety, and efficiency. For that reason, APPA supports EPA's proposal to adopt an hourly emission increase test for what is a "modification" under the NSR program, independent of any action EPA may take with respect to adopting emission guidelines for existing EGUs.

The following detailed comments will assist EPA and states develop workable requirements to reduce CO_2 emissions from affected sources. The Association and its members look forward to working with the Agency as it finalizes emission guidelines that meet the statutory requirements of the CAA and provide regulatory certainty to the electric generating industry.

III. Legal Authority

EPA's emission guidelines to address GHGs emissions from existing EGUs are consistent with EPA's legal authority under CAA section 111(d) of the Act. The Association believes it is well established that EPA's regulatory reach under section 111 is narrow and limited. The proposed ACE Rule returns EPA's guidelines to the lawful scope and bounds of section 111. Specifically, the ACE Rule will empower states to submit their own plans that establish achievable standards of performance and limit determination of systems of emission reduction to individual sources.

A. Interaction with Section 111(b)

Regulating new sources in a source category under section 111(b) of the CAA is a prerequisite to regulating 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 that "may reasonably be anticipated to endanger public health or welfare."[5] Once EPA lists a source category, the Agency must establish standards of performance for new and modified sources.[6]

In 2015, EPA promulgated new source performance standards (NSPS) for GHG emissions from new, modified, and reconstructed EGUs that cover both utility boilers and stationary combustion turbines.[7] Numerous parties, including APPA, filed petitions for review in the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) challenging the NSPS for utility boilers.[8] The litigation has been stayed pending EPA's administrative review of the NSPS. The NSPS for stationary combustion turbines were not challenged by any party.

On March 28, 2017, the President directed EPA to review the 2015 NSPS,[9] and as a result of that review a proposed rule has been sent to the Office of Management and Budget for interagency review. APPA supports revision of the NSPS for steam generating units. Meanwhile, the performance standards remain in effect because they have not been stayed or vacated.

APPA supports EPA's decision to proceed with promulgating replacement emission guidelines for existing EGUs while it undertakes review of the NSPS. Because EPA cannot regulate existing EGUs without an NSPS in place for new EGUs, APPA encourages EPA to revise or replace the NSPS for steam generating units rather than repeal them.

[5] CAA § 111(b)(1)(A).

[6] *Id.* § 111(b)(1)(B).

[7] 80 Fed. Reg. 64,510 (Oct. 23, 2015) (2015 NSPS). EPA originally made its endangerment finding for GHG emissions from motor vehicles in 2009. 74 Fed. Reg. 66,496 (Dec. 15, 2009). APPA does not support overturning or reversing that finding and does not dispute the merits of the endangerment finding.

[8] *See North Dakota v. EPA*, No. 15-1381 (and consolidated cases) (D.C. Cir.).

[9] Exec. Order No. 13783, 82 Fed. Reg. 16,093 (Mar. 31, 2017).

B. Role of the States

Section 111(d) of the CAA establishes a clear division of roles and responsibilities between EPA and states in regulating existing sources. The ACE Rule would restore EPA's traditional function of promulgating guidelines that govern the states' process of crafting their own individual plans and setting performance standards for affected sources within their borders.[10]

Under section 111(b), EPA has primary regulatory responsibility and promulgates standards of performance for new sources that reflect "the degree of emission limitation *achievable* through the application of the best system of emission reduction [(BSER)] which … the Administrator determines has been *adequately demonstrated*."[11] To determine the BSER, EPA must analyze systems of emission reduction for sources within the category and then identify the "best" one, accounting for cost and "any non-air quality health and environmental impact and energy requirements."[12]

To be "adequately demonstrated," a system of emission reduction must be "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."[13] To be "achievable," the standard 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

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[10] 83 Fed. Reg. at 44,762-63.

[11] CAA § 111(a)(1) (emphases added).

[12] *Id.*

[13] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973).

expected to recur."[14] Thus, section 111 standards are technology-based in that they are limited to what individual sources can achieve by applying certain controls.

While the definition of the standard of performance is the same for section 111(b) and section 111(d), the process for promulgating standards of performance for existing sources is entirely different. Section 111(d) explicitly requires states, not EPA, to establish standards of performance for existing sources.[15] Although EPA is responsible for identifying the adequately demonstrated BSER for a specific source category, the CAA provides states with the responsibility for developing and submitting plans that establish achievable standards of performance for individual units within their borders.[16] States must be allowed to tailor standards of performance to individual existing units based on "remaining useful life" and "other factors" the state considers relevant.[17] EPA has no authority to preclude these statutory considerations by requiring a minimum level of stringency for standards in state plans. EPA will deem a state plan "satisfactory" if it meets the emission guidelines. If the state plan fails to meet the guidelines, EPA will implement its own federal plan. Thus, states are given some flexibility to deploy different systems of emission reduction other than EPA's BSER, so long as the states meet the emission guidelines. APPA agrees that EPA's role under section 111(d) is limited to establishing federal guidelines for the states, as proposed in the ACE Rule.

[14] *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431 n.46, 433 (D.C. Cir. 1980).

[15] CAA § 111(d)(1).

[16] *Id.*; 40 C.F.R. § 60.24; *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").

[17] CAA § 111(d)(1).

C. EPA's BSER Determination

In determining the BSER for a source category, EPA may consider only those systems of emission reduction that can be applied to or at an individual source. For the reasons EPA explained in its proposed repeal of the CPP,[18] EPA interprets the CAA's text to require that BSER be limited to so-called "inside the fence" measures.[19] The Association supports EPA's determination that reduced utilization of a source cannot constitute BSER.[20] Section 111 governs standards of performance that limit how much a source emits during operation—it does not authorize EPA to require limitations on the amount of operation or prohibition on operation. EPA is also correct that the prohibition on using the Prevention of Significant Deterioration (PSD) program's standard-setting process to "'redefine the source'" being regulated extends to standard-setting under section 111.[21] The PSD program is fundamentally intertwined with NSPS under section 111(b), and the same interpretive constraints on BSER extend to existing sources regulated under section 111(d). Indeed, 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. Thus, by limiting BSER to measures that can be applied to or at the individual stationary source, EPA has realigned the definition with the statute.

[18] 82 Fed. Reg. at 48,038-42.

[19] CAA § 111.

[20] 83 Fed. Reg. at 44,752.

[21] *Id.* at 44,753.

IV. EPA's Proposed BSER for Existing Coal-Fired Utility Boilers

A. Heat Rate Improvement Measures Are the Appropriate BSER. (Comments C-2, C-9)

EPA proposes to identify "heat rate improvements" as BSER for coal-fired steam generating units.[22] APPA agrees with that proposed determination. As previously discussed, 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."[23] Although some specific methods of improving a unit's heat rate are experimental, unreasonably costly, or not widely available, heat rate improvements generally are an adequately demonstrated method of reducing a steam generating unit's CO_2 emission rate.

Various methods of maintaining or improving a unit's heat rate are already widely used in the industry in light of the strong incentives (and in some cases, obligations) currently in place for unit owners to operate as efficiently as possible. Heat rate represents the amount of heat (and correspondingly, the amount of fuel combusted) that is required to generate a given unit of electricity. Thus, by reducing the amount of heat needed to produce a unit of electricity, EGUs can reduce the amount of fuel combusted and CO_2 emitted as a function of the outputs.

Given the significant cost of fuel, owners of coal-fired steam generating units are already strongly motivated to operate their facilities as efficiently as possible. As a result, owners already have extensive experience implementing heat rate improvements as it is standard operating practice for the owners and operators of utility boilers to undertake heat improvement

[22] *Id.* at 44,755. EPA should confirm that the ACE Rule applies only to coal-fired utility boilers and not to gas- or oil-fired steam generating units.

[23] *Essex Chem. Corp.*, 486 F.2d at 443; *see also Nat. Res. Def. Council v. Thomas*, 805 F.2d 410, 428 n.30 (D.C. Cir. 1986).

measures on an ongoing basis. Public utilities and electric generating cooperatives have expressed to EPA their need to maintain heat rates to economically compete.[24] In some cases, independent system operators and state public utility commissions even require owners and operators of steam generating units within their jurisdiction to implement measures to maintain efficiency. The prominence of heat rate improvement within the industry supports EPA's conclusion that this system of emission reduction has been adequately demonstrated.

However, APPA disagrees with EPA's belief that the 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" necessarily means that "there is potential for [heat rate improvements] that can improve CO_2 emission performance."[25] The mere fact that 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 units' heat rate.

Heat rate can vary within and among steam generating units for a wide variety of reasons that are beyond the control of the unit's owner or operator. Variability in CO_2 emissions can arise from many factors, including the unit's size, operating duty, coal type, boiler design, ambient conditions, controls, and cooling system. As EPA has acknowledged, "[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

[24] *See e.g.,* Public Utility Commission of Texas CPP Comments at 42 (Dec. 1, 2014), EPA-HQ-OAR-2013-0602-23305; National Rural Electric Cooperative Association CPP Comments at 52 (Dec. 1, 2014), EPA-HQ-OAR-2013-0602-33118.

[25] 83 Fed. Reg. at 44,755.

individual units."[26] For that reason, 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.

Regardless, APPA does agree that some units have the ability to improve their heat rate—and in turn their CO_2 emission rates—although that potential "may vary considerably at the unit level."[27] Because heat rates of steam generating units can degrade over time based on many factors, efficiency-based standards will require affirmative actions by the unit's owner or operator to meet emission limitations on a continuous basis. EPA has acknowledged the realities of degradation on numerous occasions.[28] Thus, implementation of heat rate improvements will constitute a meaningful limit on CO_2 emissions by requiring units to maintain their heat rate to minimize degradation over time.

Some units may need to immediately undertake heat rate improvement projects to comply with emission standards, while other units may initially meet their standards of performance without taking any immediate measures. Eventually, however, all units will at some point be required to take heat rate measures to combat degradation. From a practical standpoint, unit owners or operators will likely undertake sufficient heat rate improvement measures to provide a substantial compliance margin beyond the state plan itself by designing plans that ensure the unit will not fall out of compliance due to natural degradation before the unit's next opportunity to perform efficiency projects. Establishing a compliance margin would minimize the potential of enforcement or noncompliance penalties for unit owners or operators.

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[26] *Id.*

[27] *Id.*

[28] *See e.g., In re Footprint Power Salem Harbor Dev., LP*, PSD Appeal No. 14-02, 2014 WL 11089298, at *9 (EAB Sept. 2, 2014) (finding permit properly accounted for degradation of turbine equipment over time that can lead to efficiency losses that directly impact greenhouse gas emissions); 80 Fed. Reg. at 64,618 (setting performance standard for combustion turbines to incorporate "a significant compliance margin for any future degradation").

Due to “inherent constraints” existing steam generating units face compared to new units, EPA similarly determined that a standard of performance based on efficient operation of steam generating units was appropriate for modified units in the 2015 NSPS.[29] The Agency concluded“[i]n light of the limited opportunities for emission reductions from retrofits, these reductions [resulting from efficiency improvements at the individual unit] are adequate.”[30] Likewise, 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 most appropriate here.

In the proposed ACE Rule, EPA discusses the potential of a “rebound effect” on CO_2 emissions, in which some individual EGUs may increase their annual CO_2 emissions because of increased utilization, due to having lower operating costs from implementing heat rate improvements.[31] At the outset, it is not clear that such an effect would even occur at individual EGUs, or how any increased emissions from greater utilization at a few units would compare to the reductions in CO_2 emission from efficiency improvements resulting from the rule. It is most likely that any potential increased utilization, if any, would come at the expense of less efficient steam generating units, which would have higher marginal costs of generation than more efficient units or renewable assets. Despite any potential rebound effect, EPA concluded that the proposed BSER would result in system-wide emission decrease from greater efficiency that would outweigh any potential system-wide increase in annual emissions from greater utilization of some units.[32]

[29] 80 Fed. Reg. at 64,600.

[30] *Id*. at 64,599.

[31] 83 Fed. Reg. at 44,756 n.17, 44,761.

[32] *Id*.

More importantly, any potential rebound effect would not disqualify EPA's proposed BSER because the Agency cannot determine that a section 111 standard is deficient simply because it is not projected to achieve a desired amount of overall emissions. Section 111 only authorizes EPA to adopt standards of performance that reflect the degree of emission *limitation* associated with applying the "best system of emission reduction," rather than requirements to achieve any absolute reduction in total emissions.[33] This means section 111 is concerned with limiting emissions, rather than requiring any absolute reduction in total emission.[34] A standard of performance cannot require more than can be achieved through application of the BSER, even if the resulting overall emission reductions are less than the standard-setting agency would prefer as a matter of policy.

EPA echoed this sentiment when it readily acknowledged that section 111 does not require each regulated EGU to achieve some amount of emission reduction.[35] Instead, EPA is only permitted to consider potential emission reductions when determining which of the available, adequately demonstrated systems of emission reduction is "best."[36] EPA—or in the case of section 111(d), states—are then 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. [37] Thus, even if there is the potential for a rebound effect, that would not necessarily make EPA's determination that heat rate improvement measures are BSER for steam generating units inappropriate.

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[33] CAA §§ 111(a)(1), 302(k).

[34] *Id.*

[35] 80 Fed. Reg. at 64,779.

[36] *Sierra Club v. Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981).

[37] CAA § 111(a)(1).

B. Candidate Technologies List (Comments C-6, C-7, C-73)

EPA has proposed a list of "candidate technologies" that states would use to apply the heat rate BSER to designated facilities in state plans.[38] Under the proposed ACE Rule, states would consider the potential for implementation of each of these candidate technologies at individual EGUs when developing standards of performance for the EGUs.[39] States would not be required to consider whether additional heat rate improvements could be implemented at the unit.[40]

APPA supports EPA's proposed use of a list of specific candidate technologies to represent the BSER that states must consider in setting standards of performance for EGUs. The proposed candidate technologies list logically focuses the states' standard-setting process on those heat rate improvements with the greatest ability to impact CO_2 emissions. Requiring states to consider all potential heat rate improvement measures in their analyses would yield immense administrative costs. EPA's use of a candidate technology list limits the burden on states preparing state plans by eliminating the need to consider measures that would almost certainly be rejected due to negligible emission reduction benefits, disproportionate costs, or availability.

Importantly, EPA did not include every possible technology or practice that might improve an EGU's heat rate on the candidate technology list. Those heat rate improvement measures that EPA excluded were inconsistent with the application of the BSER for a variety of reasons, including unreasonable cost, impact on net (rather than gross) heat rate, adverse effects on reliability, negative impacts on the control of other emissions, or lack of adequate demonstration.

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[38] 83 Fed. Reg. at 44,756.

[39] *Id.*

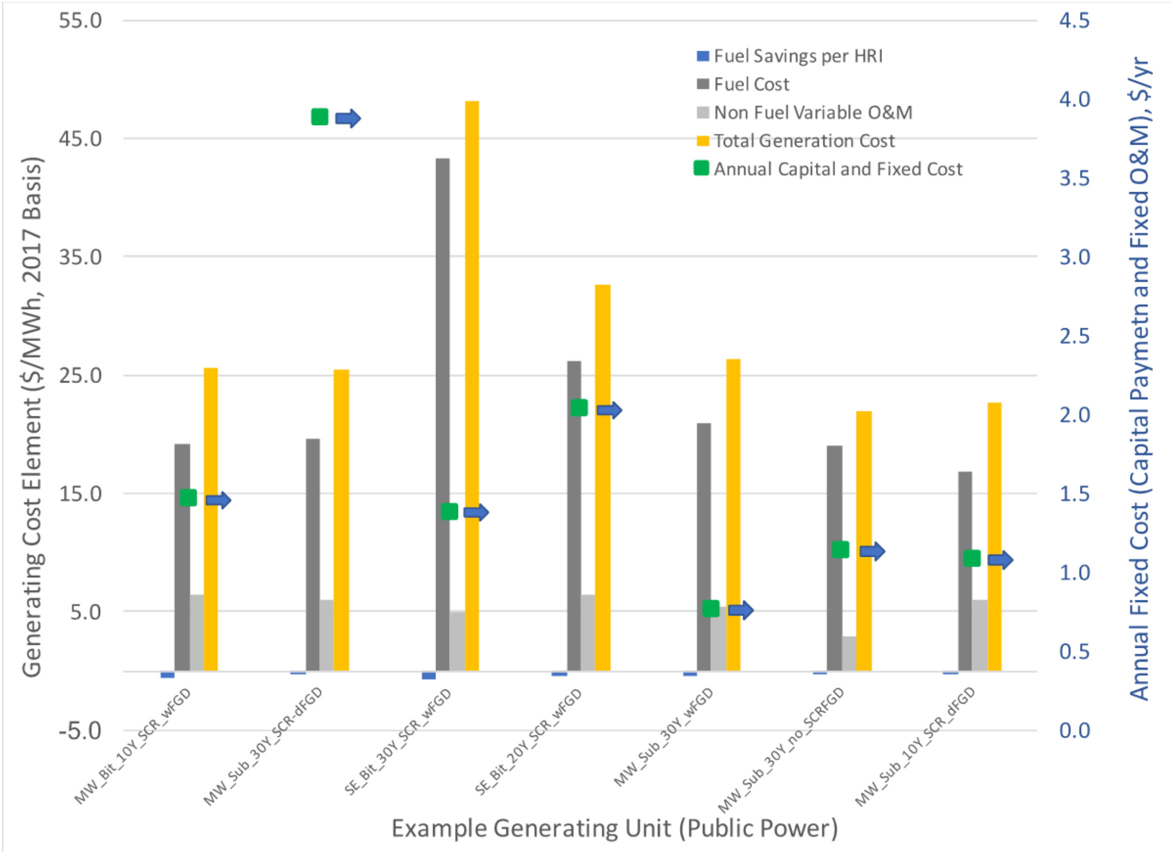
[40] CAA §§ 111(a)(1), 302(k).

C. Role of Heat Rate Improvement Actions on a Generation Costs

The Association's consultant evaluated the economic impact of implementing any or a combination of the HRI technologies identified in the ACE Rule proposal on a group of seven public power coal-fired units. The units selected varied by geographic region, age, coal type, capacity, and environmental controls. The analysis consisted of four stages: 1) the development of baseline generation costs; 2) assigning cost and performance metric to each HRI; 3) determining the cost impact of the HRI retrofits; and 4) determining the impact of the HRI on generation costs.

Figure 1 compares the various cost metrics for the seven units analyzed. The analysis indicates that the HRI candidate technologies would reduce generation costs by one to two percent. Implementation of the HRIs would produce small fuel saving compared to total generation costs. Costlier HRI candidate technologies such as a steam turbine blade path upgrade or economizer redesign or replacement offer some improvements in heat rate. However, these HRI could be outweighed if the units operate at a lower load or compromised as the HRI degrade overtime. Assuming the seven units reviewed continue to operate with no additional environmental controls, these units can be expected to be available to the market within the ACE Rule compliance time period due to the small change in generation costs. The full summary of the analysis on the heat rate improvement impacts on the select public power units is attached to these comments. (See Attachment A).

Figure 1: Comparisons of Cost Metrics: HRI on Seven Public Power Units



V. Stationary Combustion Turbines (Comments C-3, C-5, C-11)

EPA has not proposed to determine the BSER for stationary combustion turbines and, accordingly, has not proposed emission guidelines for those sources.[41] EPA requested information on what types of systems of emission reduction might be BSER for these units.[42] Combustion turbines differ from utility boilers in that heat rate improvement measures do not represent BSER for these units. 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

[41] 83 Fed. Reg. at 44,761.

[42] *Id.* at 44,754-55.

improvements they would offer.[43] The Association agrees that. unlike coal-fired utility boilers, heat rate improvements are not BSER for stationary combustion turbines, whether in simple cycle or combined cycle configuration. EPA should continue to defer action on emission guidelines for simple cycle combustion turbines. These simple cycle units do not employ a steam cycle and will likely have even fewer opportunities available for heat rate improvements than natural gas combined cycle (NGCC) units do. Also, many simple cycle units have fundamentally different operating profiles than NGCC units and require the ability to quickly ramp up or down within different load ranges. These characteristics may make it more difficult for EPA to identify a BSER for simple cycle units.

In the event EPA decides to propose a BSER for existing combustion turbines in a separate agency action, EPA could consider using a methodology similar to the one EPA used for new and reconstructed turbines under section 111(b). Namely, EPA could specify that the use of "efficient [natural gas combined cycle] NGCC technology" is BSER for "base load natural gas-fired units," while the use of "clean fuels"[44] is the BSER for "non-base load natural gas-fired units" and "multi-fuel-fired units."[45]

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[43] APPA notes that EPA's estimate in the Proposed ACE Rule of a nationwide "average [heat rate improvement] potential of 3.4 percent" for combustion turbines is false. *Id.* 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.* 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 steam generating units, 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. Further, assessing heat rate improvement potential at the national level is not a valid way to determine what improvements are available for individual units.

[44] EPA defined "clean fuels" in the 2015 NSPS to mean natural gas with some allowance for distillate oil, ethylene, propane, naphtha, jet fuel kerosene, fuel oils No. 1 and 2, biodiesel, and landfill gas. 80 Fed. Reg. at 64,601.

[45] *Id.* at 64,513 Tbl. 1, 64,614-16.

EPA defined a new and reconstructed "base load natural gas-fired unit" as a turbine that (1) combusts more than 90 percent natural gas by heat input on a 12-operating month rolling average basis, and (2) supplies to the grid more than (a) its design efficiency or 50 percent, whichever is less, times (b) its potential electric output on both a 12-operating-month and 3-year rolling average basis.[46] A "non-base load natural gas-fired unit" is one that meets the natural gas combustion criterion but not the net electric sales criterion, while a "multi-fuel-fired unit" is any combustion turbine that combusts 90 percent or less natural gas on a heat input basis.[47] Any new or reconstructed base load natural gas-fired unit must emit no more than 1,000 lb CO_2/gross MWh or 1,030 lb CO2/net MWh while any new or reconstructed non-base load natural gas-fired unit or multi-fuel-fired unit must emit no more than 120 to 160 lb CO_2/MMBtu, depending on the portion of heat input derived from natural gas.[48] This method of distinguishing stationary combustion turbines was widely accepted in the 2015 NSPS and could be used again for existing combustion turbines.

States would still have the responsibility for setting performance standards for the affected existing combustion turbines in the state. Unlike the analysis for steam generating units, however, states would not need to examine a list of potential heat rate improvement measures to determine whether they are appropriate for each unit. Rather, the state would take EPA's BSER (i.e., either "efficient NGCC technology" or "clean fuels") and establish a standard of performance for each combustion turbine that reflects application of that BSER. For most existing combustion turbines, states would set the appropriate standard of control, that could be equivalent to the NSPS.

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[46] 40 C.F.R. pt. 60, subpt. TTTT Tbl. 2.

[47] *Id.*

[48] *Id.*

VI. Affected Sources (Comment C-4)

EPA requested comment on the proposed definition of affected EGUs provided in the ACE Rule. APPA recommends that EPA implement, in addition to the exclusions presently listed, an exclusion for fossil fuel-fired EGUs that have historically limited their use to 10-15 percent or less of their annual capacity factor for the past three years and have an effective generation capacity of 150 MW or less. The exclusion of units of this type would serve the public interest and would allow EGUs that have remaining useful life to continue operation in response to market demand while limiting the environmental impact of those benefits. Smaller EGUs operating with a low capacity factor make fewer contributions to emissions than other, currently-exempt, EGUs and serve an essential need in the current market. These facilities make valuable contributions to the operation and reliability of the grid. The continued operation and maintenance of low capacity factor units, notwithstanding their infrequent use, demonstrates the continued market-based need for their existence. Units that would fall within this exemption are largely incapable of effectively recovering the cost of any remaining heat rate improvements, but they efficiently provide generation during peak load times. Imposing further compliance costs on these facilities undermines their ability to fulfill their essential purpose of increasing the reliability and resilience of the grid by supplementing available capacity in anticipation of, or in response to, peak load. Exempting EGUs with a capacity of less than 150 MW that historically operate with a capacity factor of less than 15 percent from the ACE Rule's definition of affected EGU would preserve the reliability afforded by those resources with a minimal environmental impact.

Exempting these units is not a significant departure from the definition provided in the ACE Rule proposal. The added exemption will promote the reliability and efficiency of the grid without significantly expanding the number of facilities excluded by the current definition. The parameters of this low capacity factor (LCF) exclusion ensure that its environmental impact will be minimal. Only twenty coal-fired EGUs are listed in EPA's eGrid database as falling within the LCF exclusion using 2016 data.[49] In total, these facilities produced only 316,408 tons of CO_2 emissions in that year.[50] The inclusion of the LCF EGUs in the category of "affected EGUs" would not merit the cost of applying the newly promulgated regulations to them, considering their size compared to those facilities already excluded, their remaining useful life, and their limited emissions output.

Emissions produced by facilities within the existing exemption categories far exceed that produced by EGUs that would fall within the LCF exclusion. Each of the facilities to which APPA's exclusion could be applied are significantly smaller than facilities that are already subject to exclusions under the proposed ACE Rule. For example, the threshold for the second exclusion provided in EPA's proposed definition exempts EGUs that limit net sales to one-third or less of their capacity or produce 219,000 MWh or less in net output. Facilities falling within the LCF exclusion produce a fraction of the output allowed by this second exclusion listed by EPA. In fact, the total combined net generation in 2016 for the twenty facilities that fall within the proposed LCF exclusion was 340,290 MWh.

The existence of generation that typically operates with a low capacity factor increases the reliability of the system and operates as a resource that can be used to alleviate strain on the system when demand is high. Maintaining a diverse fuel mix serves to maintain the reliability and resilience of the grid, particularly in times of extreme weather. The existence of these low capacity factor units maintains a diverse fuel supply for peak load times and would mitigate

[49] https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid

[50] *Id*.

potential exposure to volatile or extreme weather conditions, natural gas prices or supply, or the increase of intermittent generation. In the event of prolonged inclement weather, such as that experienced during the 2013-2014 polar vortex, the existence of additional coal-fired units that operate at a low capacity factor could offset some of the strain on natural gas resources during such times. As generation portfolios become increasingly reliant upon natural gas, sensitivity to a polar vortex-like event could increase. Increased demand for heating purposes in combination with the increased and changing load experienced during extreme weather impose significant demands on the supply of natural gas. The preservation of coal-fired generation operating at a low capacity factor that can meet demand under those circumstances provides a valuable hedge against such risks. These resources can be deployed in response to emergency situations or peak load times without significantly influencing overall annual emissions. Ultimately, the continued availability of relatively small steam generating units that operate at a low capacity factor will benefit the power sector as a whole and will serve the stated goals of the ACE Rule to "avoid regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation" by maintaining reliable generation using a diverse fuel supply.

VII. Unit-Specific Standards Are Appropriate.

The proposed ACE Rule indicates that states will develop standards of performance for individual 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.[51] Thus, rather than adopt uniform standards of performance for a source category or subcategory, states will adopt standards that reflect the characteristics of each individual unit. Considering the diversity of the

[51] 83 Fed. Reg. at 44,763.

existing utility boiler fleet and the variable impact of implementing the BSER at individual units, APPA supports this approach.

As APPA stated in its comments on EPA's Advance Notice of Proposed Rulemaking, 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 emissions per unit of output (i.e. efficiency).[52] Further, GHG emissions are driven by a number of factors including size, operating duty, coal type, boiler design, ambient conditions, controls, and cooling system—many of which are beyond the unit owner or operator's control—and no single factor has an overriding influence on a unit's emissions. As EPA recognizes in the proposal, the potential improvements available through BSER implementation "may vary considerably at the unit level."[53] 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.[54] Therefore, a unit-by-unit approach to standard-setting is necessary for states to develop achievable standards of performance.

VIII. Guidance for States (Comment C-14)

APPA appreciates that EPA's proposal 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. However, APPA believes that implementation of the proposed rule

[52] APPA ANPR Comments at 9-10.

[53] 83 Fed. Reg. at 44,755.

[54] *See id.* at 44,757 & Tbl. 1.

would be aided by further guidance from EPA to states as to what EPA would (or would not) consider to be aspects of a "satisfactory" state plan. The Proposal's regulatory language on required state plan elements provides a helpful general framework for states, but it leaves significant uncertainty as to what exactly is required for a state plan to be approvable.[55]

EPA can provide further direction to states for plan development without disrupting the CAA's assignment of standard-setting responsibility under section 111(d). For example, the Agency could provide a non-exclusive description of state plan approaches on certain issues that EPA would consider satisfactory if they were submitted. This type of guidance would not necessarily constrain states' discretion or disrupt the balance of federal and state roles under section 111(d) so long as EPA is clear that it is not foreclosing states from pursuing other approaches that they can demonstrate are also satisfactory. Including guidance on additional issues in EPA's guideline document will provide regulated industry with greater regulatory certainty and will ease the states' administrative burden.

Specifically, EPA should provide guidance to the states on the following points:

A. Identification of Applicable Heat Rate Improvement Measures (Comment C-23)

EPA should also provide further guidance on how states are to determine which candidate technologies apply to individual steam generating units and how implementation of selected technologies should impact a unit's standard of performance. The proposal simply requires states to "consider the applicability" of the candidate technologies at a unit, but does not specify how that analysis should be performed.[56] EPA should at least clarify that this analysis does not require states to simply add together the heat rate improvement potentials listed in Table

[55] *See id.* at 44,808-09 (Proposed 40 C.F.R. §§ 60.5735a-60.5755a).

[56] *See id.* at 44,809 (Proposed 40 C.F.R. § 60.5755a(a)(2)).

1 for measures that have not been implemented at a unit and apply the total percent reduction to the source's most recent CO_2 emission rate. Instead, a satisfactory plan must reflect a unit-specific evaluation of the degree to which each candidate technology can actually improve heat rate at the unit, based on the unit's design, operational history, expected future operations, current state of repair, prior heat rate improvement activities, and other relevant factors.

The value of any particular heat rate improvement measure will vary from unit-to-unit, and such 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. The proposed rule includes some brief statements to this effect, noting that states "will use the information provided by EPA as guidance, but will be expected to conduct unit-specific evaluations of [heat rate improvement] potential, technical feasibility, and applicability for each of the BSER candidate technologies."[57] However, EPA should emphasize in the final rule that this unit-specific analysis is an essential part of the standard-setting process for any satisfactory state plan. Such guidance would ensure that performance standards are not based on heat rate improvement measure determined not to be cost-effective for a unit, even if a particular unit has not implemented all of the listed heat rate improvement measure that EPA has demonstrated represent BSER.

Further, EPA should require states 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. A satisfactory state plan must contain standards based on application of the BSER to existing units, and economic feasibility is a key component of ensuring that the BSER has been adequately demonstrated. EPA should

[57] *Id.* at 44,763.

consider providing guidance on potential cost or cost-effectiveness thresholds that states can use to determine whether a particular heat rate improvement technology is appropriate for a unit. For example, EPA could state that where the costs of implementing a heat rate improvement measure at a particular unit are inconsistent with the assumptions underlying EPA's candidate technologies list—that is, where the costs would be positive on net—then that measure is not "applicable" to the unit for purposes of standard-setting.

Finally, EPA should clarify in the final rule that the analysis of what heat rate improvements are applicable to an individual unit need not be wholly performed by the state itself but can rely on information provided by source owners and operators. Then, EPA should deem a state plan satisfactory if the state has allowed source owners to self-audit or retain third-party consultants to evaluate their units' heat rate improvement potential and to submit those results to the state for review. 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.

B. Important Factors States Must Consider (Comments C-22, C-23, C-24)

APPA encourages EPA to adopt regulatory language that requires states to demonstrate that they have accounted for specific factors in their state plan, specifically, heat rate degradation, representative baseline conditions, future operating conditions, and variability of the continuous emissions monitoring system (CEMS). As noted above, the proposed emission guideline does not contain any provisions addressing the standard-setting process, other than the requirement that states "consider the applicability" of listed heat rate improvement measures.[58] Without additional instruction from EPA, the states, which lack EPA's experience in assessing what degree of emission limitation is "achievable" for purposes of section 111, may fail to consider important factors that affect a unit's emission performance and adopt standards that are not achievable.

For example, EPA should require that achievable standards account for the fact that a unit's heat rate naturally degrades over time. As noted 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. Accordingly, states should set each unit's standard of performance at a level that reflects the likely degradation over the course of the unit's maintenance cycle, rather than what the unit's heat rate will be immediately after implementing any applicable measures from the list of candidate technologies. Furthermore, EPA should clarify how states consider remaining useful life. If the unit is near retirement, certain heat rate improvement measures may not be appropriate because the unit could not reasonably expect to recover its costs.

Similarly, EPA should make clear that the states should consider whether they are establishing standards of performance based on representative baseline conditions for the unit. In response to the natural degradation, unit owners routinely take steps to maintain their heat rates and may do so on a regular maintenance cycle. A unit's heat rate shortly after maintenance may not represent how the unit will perform in a few years near the end of its maintenance cycle. Therefore, states should consider whether an earlier baseline period is more representative of the unit's future performance, and not just set a standard based on assumed reductions at the time the

[58] *Id.* at 44,809 (Proposed 40 C.F.R. § 60.5755a(a)(2)).

standard is established. Performance standards that are representative of earlier baseline period will recognize prior heat rate improvements, giving credit to utilities that have already undertaken heat rate improvement projects. For example, the owners of Laramie River Station (LSR) have been proactive in their attempts to improve heat rate efficiency at the three LRS units. Heat rate improvements completed at LRS include turbines upgrades, installation of an intelligent soot blowing program, hydrojet installation to clean boiler walls, and installation of carbon monoxide monitors and combustion optimizer. [59] Allowing states to consider an earlier baseline period when setting a performance standard would more appropriately recognize these prior heat rate improvement projects.

EPA should also make clear that states should examine multiple years of emissions data for each unit. Due to the lower cost of natural gas in recent years and its effect on the load duty of coal-fired EGUs, any standard of performance based on a unit's historical emissions performance should evaluate multiple years. The Association believes this should be no less than five years and that a period of ten years would be preferable. Shorter periods of time may not capture the different operating conditions and operating loads of the unit. Moreover, the emissions data smooths out over longer periods of time, removing spikes and other abnormalities seen in shorter review periods.

Finally, EPA should clarify that states should account for anticipated changes in how a unit may be deployed. Operating load plays a significant role in 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. If a unit is expected to operate differently in the future, the state should consider how that operating profile will affect the unit's CO_2 emissions

[59] Some of the heat rate improvement measures completed by LRS are not among the EPA identified BSER candidate technologies, such as the hydrojet and CO monitor.

and demonstrate that its standard of performance will not prevent the unit from operating as needed.

IX. Confidential Business Information (Comments C-46, C-72)

EPA should provide protection for confidential business information. The requirements in proposed 40 C.F.R. § 60.5740(a) require states to submit to EPA very specific information regarding each affected unit. Some of the information required would be considered to be confidential business information, competitive electric information, or information that is otherwise sensitive regarding energy security and reliability that is normally not disclosed to the public. Examples could include fuel prices, fixed and variable operations and maintenance costs, and wholesale electricity prices. Given that this information is required by the proposed regulation to be included in state plan submissions, and that the plan must be subject to a public hearing, EPA should make clear that certain data submitted for review by the state agency can be held confidential if it meets the requirements of state open records law or federal Freedom of Information Act.

X. Compliance Periods (Comments C-13, C-22, C-73)

EPA proposes to leave states the discretion to set compliance periods for the standards of performance applicable to individual steam generating units in the state, provided the start of any compliance period extending more than 24 months from the date required for plan submittal includes legally enforceable increments of progress.[60] APPA requests that EPA increase the proposed amount of time from 24 months to 36 months before enforceable increments of progress are required because this will line up better with the typical scheduled outage periods for utility boilers. Weather can affect scheduled maintenance outage periods to implement

[60] *Id.* (Proposed 40 C.F.R. § 60.5750a).

improvement projects because when record temperatures occur (either cold or hot), EGUs are often required to run, which can cause planned outage periods to be significantly changed. Increasing the period of time from 24- months to 36-months assists with this problem. The Association also requests that EPA change the trigger for the time period before enforceable increments of progress are required from the date required for plan submittal to the date EPA approves a state plan to avoid a situation where investments are made to comply with a submitted state plan that EPA does not ultimately approve.

APPA supports EPA's proposal to give states the discretion to set the compliance periods for the individual EGUs in the state. In particular, EPA should allow states to adopt different compliance deadlines for individual affected EGUs based on remaining useful life, cost, technical feasibility, and other factors. Some units may become subject to performance standards based on implementation of several candidate technologies, while others become subject to "business as usual" standards because they are not able or do not need to implement any of the candidate technologies. A unit that is expected to take several measures to substantially improve its heat rate may need additional time before its initial compliance period begins. In the case of public power utilities, additional time may also be required to obtain the necessary board or council approvals for substantial heat rate improvement projects.

Public power utilities use municipal bonds to finance investments in power generation transmission, distribution, reliability, demand control, efficiency, and emission control projects. Municipal bonds are unique in that they have maturities nearly twice as long as corporate bonds and are generally issued as a series with varying maturities, rather than a single maturity. A public power utility is limited in how they raise capital, compared to investor owned utilities which rely exclusively on the capital markets through corporate debt and equity. As not-for-profit entities of local government governed by local city councils or elected or appointed boards, public power utilities will have to undergo varying steps to obtain approval to implement some of the heat rate improvement projects contemplated by the ACE Rule. The utilities' governing body must meet and determine if the project is necessary, and review and approve staff plans to implement the efficiency option(s) selected. The city council or board must meet to pass a resolution to finance the project, and then a bond counsel is assembled. The bond process could take six months to one year, followed by an additional year to decide on the bond product. Then there is a three- to six-month process to raise electricity rates to recover the capital costs for the project over the remaining useful life of the unit. The process public power utilities must undergo to raise capital should be factored into the compliance timeframe.

In addition, EPA should clarify that states may consider individual units' planned outage schedule in setting compliance deadlines for those units. Existing EGUs typically undertake projects to improve or maintain their efficiency on regular multi-year maintenance schedules. Allowing state plan implementation to coincide with planned outages will reduce the overall cost of EPA's proposed rule without compromising its environmental goals.

XI. Alternative Forms of Performance Standards (Comments C-15, C-16)

EPA proposes that states must set a standard of performance for each 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)."[61] EPA suggests in the preamble that this particular form "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

[61] *Id.* (Proposed 40 C.F.R. § 60.5755a(a)).

"creates a more streamlined evaluation for EPA to consider in state plan evaluation as there are fewer variables to consider."[62]

APPA disagrees that standards of performance should be limited to standards expressed as pounds of CO_2 emitted per MWh. Instead, states should have the discretion to select alternative forms of the performance standard. The statute gives states broad authority in this regard, which EPA should not impinge upon. To the extent that a state wishes to adopt standards of performance that take a different form, the state should have the opportunity to demonstrate that the alternative form is "satisfactory." A state plan should be considered satisfactory so long as its standards of performance can be shown to reflect the "degree of emission limitation achievable through the application of the [BSER]."[63]

For example, because a unit's heat rate and CO_2 emission rate can vary significantly by operating load, EPA should not limit states to adopting one standard of performance that covers all periods of operation. A state may wish to adopt multiple standards that apply to different load ranges (e.g., a standard for full load operations versus operating at 30-40 percent capacity). Likewise, states should be allowed to adopt standards of performance that are expressed in terms of mass of CO_2 emitted over various periods of time, such as per hour or per year. As long as each standard of performance reflects application of the BSER to the unit, any such approach should be satisfactory for EPA.

However, where a state opts to adopt standards expressed in terms of CO_2 emitted per unit of output, EPA should not require that the standard be based on net output. A net output-based standard could be unworkable, unnecessary, and could require implementation of costly

[62] *Id.* at 44,764.

[63] CAA § 111(a)(1).

new monitoring measures, whereas gross output is straightforward, simple, consistent, directly measured, and already reported to EPA for other purposes as required by 40 C.F.R. Part 75. For a number of reasons, it would be inefficient for states to require compliance with net output-based standards. First, gross output is already monitored and reported to EPA under Part 75, providing a source of information for states to establish standards of performance. No data are similarly accessible for net output. Second, to comply with a net output-based standard, EGUs would need to develop additional monitoring to determine auxiliary load within the plant and to allocate that load between units at the facility. The data would also need to be available in real time to operators, so they can take corrective action. This type of monitoring system would come with endless complications and would be costly and impractical. Third, the most commonly cited motivation for encouraging use of net output-based standards is to promote more efficient electricity generation, but EGUs already have more than adequate incentives to minimize auxiliary load and operate as efficiently and cost-effectively as possible. Many utilities operate in competitive markets, in which the least cost units are generally dispatched first. Likewise, public power utilities maximize efficiency because any cost savings are passed on directly to customers. 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 minimize the amount of fuel required per unit of electricity supplied to the grid. Finally, expressing CO_2 emission rate limits in terms of net output would need to fully reflect effects of installing and operating emission control technology. Emission controls, such as scrubbers, can impose substantial auxiliary load requirements, causing a significant decrease in net output, which would increase a unit's CO_2 emission rate in terms of lb/MWh-net. For all these reasons, APPA asks

EPA to clarify that net output-based standards are not required for a satisfactory state plan under the ACE Rule.

XII. Emissions Averaging Between Affected EGUs (Comments C-28, C-29, C-30, C-31, C-32, C-34, C-38, C-40, C-41)

It is essential in any final emission guideline for EPA to recognize the full scope of states' authority to provide flexible options for affected EGUs to comply with their standards of performance. EPA has a long history of promoting flexible compliance under CAA regulatory programs, including section 111(d). Flexibility allows sources to achieve the CAA's environmental goals while minimizing cost.[64] It also provides incentives for sources to pursue additional emission reductions beyond those required by a rule.

EPA has proposed to allow states to include some forms of flexible compliance in their state plans. Specifically, the proposed ACE Rule would allow states to incorporate emissions averaging among steam generating units across a single facility.[65] APPA agrees that states should be allowed to incorporate these options into their state plans. Averaging and other market-based mechanisms are the most cost-effective way for affected units to implement control requirements.

However, APPA strongly disagrees with EPA's position that the CAA does not allow states to provide broader forms of compliance flexibility than averaging within a single facility. Although the *standards themselves* must be premised on application of the BSER to an individual source, and cannot be established in reliance on the potential availability of flexible compliance options, the CAA allows states to *implement* those standards through a wide variety

[64] *See Michigan v. EPA*, 135 S. Ct. 2699 (2015) (recognizing importance of considering cost in agency rulemaking).

[65] 83 Fed. Reg. at 44,767.

of flexible options, including averaging among affected EGUs within a plant, averaging among affected EGUs within a corporate fleet, or even averaging or trading with unaffiliated affected steam generating units within the state.

EPA has expressed concern that allowing averaging or trading beyond a plant may lead to generation shifting away from the affected source category.[66] Provided that averaging or trading is allowed only between affected steam generating units of the same type (i.e., steam generating units subject to the ACE Rule may average only with other steam generating units in the state subject to the ACE Rule), then EPA's concern about generation shifting is resolved. Generation shifting would occur only if higher emitting units (i.e., steam generating units burning coal) were able to average with lower emitting units (i.e., combustion turbines burning natural gas) or with units not subject to the rule.

EPA also expresses concern that averaging and trading 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."[67] This interpretation misreads the statute. Nothing in the CAA requires performance standards to be implemented using the same methods considered in setting them. EPA even acknowledges that performance standards do not need to be implemented using the same emission control measures used to develop the performance standard. The ACE Rule indicates that affected sources can use both BSER and non-BSER measures to achieve compliance with state plan requirements.[68]

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[66] *Id.* at 44,768.

[67] *Id.* at 44,767.

[68] *Id.* at 44,765.

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."[69] Allowing averaging and trading among affected EGUs of the same type within a state is no different than allowing an affected steam generating unit to comply with a standard of performance using emission reduction systems that do not represent BSER. While EPA may not *require* a source to meet a standard of performance based on the emission reductions associated with carbon capture and sequestration (CCS), it must *allow* the source to use CCS to meet a standard of performance that is based on applying the BSER. Similarly, while EPA may not require an EGU to meet an emission limit based on averaging its performance with other EGUs, it is perfectly consistent with the statute to allow the EGU to average its performance with other EGUs to show compliance.

EPA also expresses 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."[70] But section 111 is explicit that EPA may not require affected sources to implement any specific system of emission reduction, including the BSER: each source's obligation is simply to comply with its standard of performance.[71]

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."[72] Again, the CAA establishes a clear distinction between the standard-setting

[69] CAA § 111(d)(1) (emphases added).

[70] 83 Fed. Reg. at 44,768.

[71] *See* CAA § 111(b)(5).

[72] 83 Fed. Reg. at 44,767.

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 obviate the need to consider 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 national ambient air quality standards (NAAQS), including authority to implement emission limitations through "economic incentives such as fees, marketable permits, and auctions of emissions rights."[73] 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 nitrogen oxides emission

[73] CAA § 110(a)(2)(A).

credits."[74] In the Clean Air Mercury Rule,[75] 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. 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 to implement the NAAQS, and EPA cannot disapprove a state implementation plan based on its disagreement with the state's policy choices so long as it meets the minimum statutory requirements.[76] State discretion is at least as broad in the context of section 111(d), as EPA has repeatedly emphasized in the Proposed ACE Rule.[77]

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

XIII. Proposed Revisions to the Implementing Regulations (Comment C-50)

A. Health and Welfare Distinction

APPA supports EPA's proposal to eliminate Subpart B's distinction between health- and welfare-based pollutants that currently exist in the implementing regulations.[78] Some have read 40 C.F.R. § 60.24(c) to require that state standards of performance must be no less stringent than EPA's emission guidelines for health-based pollutants, while some have suggested that

[74] 40 C.F.R. § 60.33b(d)(2).

[75] 70 Fed. Reg. 28,606 (May 18, 2005).

[76] *See Union Electric Co. v. EPA*, 515 F.2d 206 (8th Cir. 1975).

[77] *See* 83 Fed. Reg. at 44,748, 44,749, 44,750, 44,765 (discussing state role in 111(d) process).

[78] *Id.* at 44,773.

§ 60.24(d) allows states to apply less stringent standards only to public-welfare based pollutants. While there are other readings of this provision, EPA's proposal would eliminate any confusion. This alleged distinction has no basis in the statute, and EPA "does not believe the nature of the pollutant in terms of its impacts on health and/or welfare impact the manner in which it is regulated under this provision."[79] APPA supports this clarification and views EPA's current proposal as an effort to conclusively eliminate any potential confusion that the two terms ever established different standards.

B. Remaining Useful Life and Other Factors (Comments C-57, C-58)

APPA agrees that EPA has no authority to restrict when states may consider remaining useful life and other factors in setting performance standards found in Subpart B of the existing regulations.[80] EPA has solicited comment and now proposes amending the variance provision to reflect additional factors that may be considered in setting performance standards, consistent with section 111(d)(1)(B).[81] 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.[82] APPA supports this modification, and 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. In addition, APPA encourages the Agency to permit states to consider an affected source's prior heat rate improvement project in establishing a standard of performance for a particular source. Given the unique attributes and aspects of each affected source, attempts to further reduce the heat rate at a source that has already implemented significant heat rate

[79] *Id.*

[80] *Id.*

[81] *Id.*

[82] *Id.* at 44,769.

improvements may, in certain cases, be contrary to sound engineering and operating principles. In fact, such efforts could result in a loss of efficiency, which would be counterproductive and increase operational costs.

C. Presumptive Emission Standard

APPA 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 only require the inclusion of information on the degree of emission reduction achievable through the application of BSER.[83] As EPA notes, the preambles for both the proposed and final Subpart B regulations suggest an "emission guideline" would presumptively reflect the degree of emission limitation achievable by BSER.[84] 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. Nevertheless, APPA agrees that redefining "emission guideline" as "a final guideline document published under § 60.22a(a)" would prevent any future confusion regarding its meaning,[85] and would give "emission guideline" a definition that is consistent with the statute.

D. New Deadlines for State Plans (Comments C-52, C-53, C-54, C-55)

APPA 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 state implementation plans.[86] Based on its extensive experience working with states, EPA believes that the current nine-month deadline to

[83] *Id.* at 44,771.

[84] *Id*.

[85] *Id.* at 44,804 (Proposed 40 C.F.R. § 60.21a(e)).

[86] *Id*. at 44,771.

create a state plan under section 111(d) is insufficient.[87] Thus, under the proposed regulations, the deadline to submit a state plan would be extended to three years after the promulgation of final emission guidelines. EPA also proposes giving the Agency twelve months to take action on the state plan once it is received.[88] EPA finds prolonging the review period from the current four months to twelve months would provide the Agency adequate time to review and follow the necessary notice-and-comment rulemaking procedures.[89] 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.[90] The proposed time requirements align with the deadlines laid out in section 110.[91] APPA 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 state plans, nothing prevents states from submitting their plans ahead of those deadlines. EPA should clarify, however, that if a state submits its plan early, the provisions regarding affected source compliance deadlines (e.g., the requirement for enforceable progress increments) begin from the later of the date required for plan submittal or the date the plan is approved—not the date the plan is submitted. Under the current regulations, a state is required to provide "increments of progress" if its compliance schedule extends more than twelve months from the date the plan is due.[92] EPA proposes extending this trigger to twenty-four months[93] (and as discussed above in

[87] *Id.* at 44,769.

[88] *Id.* at 44,771.

[89] *Id.*

[90] *Id.*

[91] *See* CAA § 110.

[92] 40 C.F.R. § 60.24(e)(1).

[93] 83 Fed. Reg. at 44,772.

Section X, the Association believes this trigger should be extended even more to thirty-six months). As is also discussed in Section X, APPA believes the trigger should be tied to the date EPA approves the state plan, not the plan's due date. Thus, EPA should include explicit language that informs states that the time period (whether twenty-four or thirty-six months) begins to run from either the date the plan is due or the date the plan is approved, whichever is later, and not the date that the plan is actually submitted. If EPA fails to make this clear, states might refrain from submitting completed plans early for fear of triggering the twenty-four or thirty-six month time period.

XIV. NSR Applicability Provisions (Comments C-62, C-67)

APPA supports EPA's proposal to reform the NSR program's applicability provisions. EPA's expansive interpretation of the CAA's NSR provisions has been a source of regulatory uncertainty for the utility industry for almost two decades and has discouraged source owners from carrying out projects that would maintain or improve the safety, reliability, and efficiency of their facilities. Under the current system, candidate technologies for meeting the ACE Rule may become cost-prohibitive if they are determined to trigger NSR, and sources are vulnerable to after-the-fact second guessing by EPA and third parties regarding the determinations of NSR applicability. This uncertainty has resulted in adverse economic repercussions for the power generation sector by creating a disincentive to undertake projects that can improve efficiency and productivity of the existing generation fleet. Because of this uncertainty, some projects have experienced lengthy permitting delays, potential enforcement actions, and incurred large capital retrofit costs. In addition, the uncertainty has created a strong disincentive to undertake efficiency projects that can cost-effectively reduce CO_2 and other air emissions.

The proposed ACE Rule provides a timely opportunity to address these issues and promulgate long-needed revision to the NSR applicability provisions. This is especially true when one considers EPA's previous NSR efforts targeting heat rate improvements. APPA disagrees that the heat rate improvement measures of EPA's proposed candidate technologies list are the types of projects that generally trigger NSR as major modifications. Nevertheless, EPA's enforcement arm and citizen suit plaintiffs have repeatedly targeted these projects in lawsuits, accusing sources of undertaking major modifications without undergoing NSR. Without the proposed changes to the NSR applicability analysis, sources will face similar allegations that they have triggered NSR simply by taking action to comply with the requisite performance standards under the ACE Rule; or if a project is determined to trigger NSR, the high cost of NSR could eliminate it as BSER.

In any event, APPA notes that EPA's proposed changes to the NSR program are justified and necessary even in the absence of the ACE Rule. Adoption of an hourly emissions rate increase test for modifications will promote the safety, reliability, and efficiency of EGUs. Thus, APPA urges EPA to move ahead with revising the NSR regulations, regardless of how EPA decides to proceed under section 111(d).

Given the obvious benefits to an hourly emission test, APPA supports the proposed scope of EPA's reform to the NSR program, including its proposal to make the new hourly emissions rate increase test available for all EGUs (as defined at 40 C.F.R. § 51.124(q)).

A. Historical Context of NSR

In order to properly address the specific changes EPA has proposed for NSR applicability, some historical context is necessary to explain the origin of the current NSR regulations. The terms "modifications" and "major modification" as used in the NSR and NSPS programs are the result of evolving interpretations of the relevant statutory provisions through the interaction of EPA rulemaking and judicial decisions.

The concept of modification originated with section 111's NSPS program in the 1970 CAA, which 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."[94] The statutory definition of modification under section 111 has remained unchanged.

In 1971, EPA adopted implementing regulations that largely defined "modification" to match the statutory definition. Then, in 1975, EPA amended the NSPS regulation to clarify that "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 shall be considered a modification."[95] The 1975 amendment also designated the relevant emission rate as kilograms per hour.[96] Therefore, EPA's NSPS—which are still effective—determine whether a "modification" under section 111(a)(4) has occurred based on whether the maximum hourly emissions increased after the project.

Meanwhile, EPA established the first NSR program by regulation in 1974, before Congress established the statutory PSD and Nonattainment NSR Programs.[97] It adopted the NSPS programs' definition of modification, including its focus on increases in a source's hourly emissions rate.[98]

In the 1977 CAA Amendments, Congress created the statutory PSD and Nonattainment NSR programs, and in both cases defined "modification" by cross reference to the section 111

[94] CAA § 111(a)(4).

[95] 40 C.F.R. § 60.14(a) (emphasis added).

[96] *Id.* § 60.14(b).

[97] 39 Fed. Reg. 42,510 (Dec. 5, 1974) (1974 PSD Rule).

[98] *Id.* at 42,513

definition for NSPS.[99] EPA's 1978 PSD Rule defined a new term, "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."[100] Under these rules, a project must be a "modification" as previously defined in the 1974 PSD rules and the NSPS rules to potentially be a "major modification."

In *Alabama Power Co. v. Costle*, the D.C. Circuit reviewed EPA's 1978 PSD Rule and held that while EPA may limit PSD to "major modifications," its authority to exempt certain emission-increasing projects from review is limited to de minimis increases.[101] The court also held that the CAA limits NSR applicability to changes that cause a *net* increase in emissions, effectively requiring EPA to incorporate the "bubble concept" into its NSR rules.[102] Specifically, the D.C. Circuit found industrial changes that do not produce a net increase in any pollutant "are not 'modifications' at all."[103]

EPA promulgated its 1980 NSR Rule in response to the court's decision in *Alabama Power*.[104] The Agency revised the "major modification" analysis to require a significant net emissions increase and to shift from the 1978 rule's "potential-to-potential" analysis of pre- and post-change annual emissions to an "actual-to-actual" test.[105] Initially, EPA interpreted the rule to trigger NSR for existing facilities only if the source underwent changes that would increase

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[99] 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 §§ 160-169, 171-178).

[100] 43 Fed. Reg. 26,388, 26,403 (June 19, 1978) (1978 PSD Rule).

[101] 636 F.2d 323, 360 (D.C. Cir. 1979) (per curiam).

[102] *Id.* at 401-03.

[103] *Id.* at 401.

[104] 45 Fed. Reg. 52,676 (Aug. 7, 1980) (1980 NSR Rule).

[105] *Id.* at 52,735-36.

the unit's maximum hourly emission rate because any emission increase due to greater utilization would be categorically excluded.[106]

However, in the late 1980s, EPA began to assert the test required from existing emissions units was an "actual-to-potential" annual emission approach. The Agency insisted that when an existing emission unit undergoes changes, the post-change unit has been "modified" and thus had "not begun normal operations," meaning that its "actual emissions" for the post-change period must be calculated as its potential to emit. The United States Court of Appeals for the First Circuit (First Circuit) upheld this test when it was applied to the wholesale replacement of an existing unit.[107]

Shortly after the First Circuit's decision, the United States Court of Appeals for the Seventh Circuit rejected the EPA's actual-to-potential reading of the 1980 NSR Rule as applied to renovation of an existing electric utility steam generating units (EUSGU), holding that the regulations required some measure of expected actual post-project emissions.[108] The court found that 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 an already operation unit.[109]

In response, in 1992, EPA promulgated the "*WEPCo* Rule" revising the NSR regulations to provide an "actual-to-projected-actual" emissions increase test for existing EUSGUs, but retaining the 1980 provisions for other sources.[110] Under this rule, emissions would be

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[106] *See Envtl. Def. v. Duke Energy Corp.*, 549 U.S. 561, 580-81 (2007) (discussing Reich determinations).

[107] *See Puerto Rican Cement Co. v. EPA*, 889 F.2d 292 (1st Cir. 1989).

[108] *Wis. Elec. Power Co. v. Reilly,* 893 F.2d 901 (7th Cir. 1990) (*WEPCo*).

[109] *Id.* at 917.

[110] 57 Fed. Reg. 32, 314 (July 21, 1992).

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 a physical change or change in method of operation of a unit."[111] In 2002, EPA promulgated the NSR Reform Rule, which made the "actual-to-projected-actual" emissions increase test available for major modification of all existing sources and extended the baseline period for analyzing non-EUSGU's pre-project emissions to 10 years.[112]

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 unchangeable 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.

B. The Proposed Hourly Emissions Increase Test Is Lawful.

EPA's proposed approach of adopting an emissions increase test for modifications based on changes in a unit's maximum hourly emissions falls squarely within the Agency's statutory authority. Although courts have recognized that a modification must be based on increases in actual emissions, the CAA does not require EPA to focus on annual emission rather than hourly (or some other time frame in evaluating emission increases). Moreover, the D.C. Circuit has repeatedly recognized that the CAA grants EPA broad discretion to give meaning to the term "increases," including the timeframe over which those increases are measured. Because EPA's

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[111] *Id.* at 32,336-37.

[112] 67 Fed. Reg. 80,186 (Dec. 31, 2002).

proposed maximum achieved, and maximum achievable approaches capture actual emissions, they clearly do not contravene the statute.

1. EPA Has Broad Discretion

Both the PSD and Nonattainment NSR provisions define "modification" by cross-reference to section 111, which describes "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."[113] Given this broad definition, the D.C. Circuit recognized the wide latitude Congress gave EPA to give meaning to the term "modification" and to determine what constitutes an increase in emissions in *New York v. EPA* (*New York I*).[114] The court held "[i]n enacting the NSR program, Congress did not specify how to determine 'increases' in emissions, leaving EPA to fill in that gap while balancing the economic and environmental goals of the statute."[115] The court also 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."[116]

In 2006, the D.C. Circuit reaffirmed EPA's broad discretion under the CAA to define the emission criterion for modification. In *New York II*¸ the court highlighted EPA's discretion to determine what emission increases trigger NSR by contrasting it with Congress's clear direction

[113] CAA § 111(a)(4).

[114] 413 F.3d 3 (D.C. Cir. 2005).

[115] *Id. at* 27.

[116] *Id.* at 23-24.

as to what physical changes may constitute modifications.[117] According to the D.C. Circuit, while Congress spoke clearly in stating that "any physical change" may be a modification, its use of the word "increases" "necessitated further definition regarding rate and measurement for the term to have any contextual meaning."[118] As demonstrated by the decisions in *New York I* and *New York II*, EPA's wide latitude to define what emissions increases are relevant for purposes of NSR modification analysis is well established.

2. EPA's Proposed Alternatives Both Measure "Actual" Emissions (Comment C-63)

In *New York I*, the court 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." Therefore, while EPA has broad discretion to define what constitutes an emission increase, it must at least base that definition on some measure of what a source actually emits or will emit.

EPA's proposed "maximum achieved" and "maximum achievable" hourly emission increase tests both satisfy this condition. A test based on the source's maximum achieved emissions (whether expressed as a statistical analysis or a "once in five years" test) would clearly meet this requirement, as it is based on the amount the source actually emitted and will emit before and after the project. In effect, the current significant emissions increase test for major modification, which was upheld by the D.C. Circuit in *New York I*, is itself a "maximum achieved" test as it compares pre-project emissions to "the maximum annual rate" at which the source is projected to emit in the post-project period.

[117] *New York v. EPA*, 443 F.3d 880 (D.C. Cir. 2006) (*New York II*).

[118] *Id.* at 888-89.

The proposed "maximum achievable" test also compares actual emissions. As EPA notes, this test examines what a source has actually been able to emit based on physical and operating capacity during a representative period prior to the change. The proposed "maximum achievable" test mirrors the NSPS program's modification test, which uses actual testing to evaluate the unit's emission rates unless the use of emission factors and engineering analysis clearly demonstrate whether emissions will increase.[119]

The proposed "maximum achievable" test is also an acceptable method for EPA to identify emission increases because it is consistent with the way modifications have been determined in the NSPS program since its inception, and with the way modifications were determined under the PSD program when Congress enacted the NSR provisions in 1977 and defined modification by cross-reference to the NSPS program. Even if Congress did not require that "modification" have the same meaning under NSR as it does under NSPS, it certainly did not prohibit that approach.[120]

3. The CAA Does Not Preclude the Hourly Emission Increase Test. (Comment C-65)

EPA's authority to define what constitutes "emission increases" includes the discretion to base its test on hourly emission increases. As noted above, the EPA is able to determine how to calculate emissions increases because "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."[121] Therefore, adopting an hourly emission increase test for modification is a permissible interpretation of the statute that will promote the CAA's environmental and

[119] *See* 40 C.F.R. § 60.14(b); *see also* 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).

[120] *See New York I*, 413 F.3d at 19.

[121] *Id.* at 27.

economic goals. Moreover, EPA has used an hourly emission increase test under the NSPS program for over four decades. And Congress has at least indicated that an hourly approach would be permissible under NSR by cross-referencing section 111's definition of "modification," and declining to explicitly reject the NSPS and PSD programs' preexisting focus on hourly emissions in the 1977 CAA Amendments (even while the 1977 CAA Amendments did specify that certain other aspects of the 1974 PSD Rule would be changed immediately by operation of the statute).

The D.C. Circuit has rejected previous efforts to place temporal boundaries on how EPA may determine emission increases. In *New York I*, petitioners objected to EPA's decision to provide for a pre-change baseline period of "'any consecutive 24-month period selected by the [source] within the 10-year period immediately preceding [the change].'"[122] Specifically, petitioners argued that the source must compare emissions immediately before and after the project.[123] Otherwise, they insisted, the new 10-year baseline would allow large emissions increases to occur. However, the court noted the term "increases" did not set any temporal boundaries and upheld EPA's reasonable selection of time frames for analysis.[124]

Because the changes proposed here mirror those proposed in a 2007 supplemental notice of proposed rulemaking, EPA's proposed alternatives have already been the subject of public comment.[125] While some groups argued EPA lacked the authority to adopt an hourly emission increase test, none of their arguments presented in those comments have merit.

[122] *Id.*at 22-23 (citation omitted).

[123] *Id.* at 22-23.

[124] *Id.* at 23.

[125] 72 Fed. Reg. 26,202 (May 8, 2007) (2007 Proposal).

Previous commenters claimed an hourly emissions test is *per se* not an "actual" emissions test because it would overlook actual increases in annual emissions due to increased utilization of the source.[126] This argument fails because it simply presupposes that annual emission are the only relevant emissions. Under Title I of the CAA, EPA has adopted different averaging times for both the NAAQS and PSD increments. There is no reason for the modification test to focus on one particular one. Moreover, the current NSR regulations, which focus only on increases in annual emissions, arguably fail to capture "actual" increases in both short-term emissions and emissions averaged on periods exceeding one year. Here, EPA is proposing both an hourly test for "modification" and an annual test for "major modification."

Objectors to the previous 2005 and 2007 proposals also argued that other provisions of the CAA indicate that modification analysis for NSR must be based on annual emissions.[127] Specifically, these commenters 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), 173(c)(1) (requiring offsets in nonattainment areas to cover the "total tonnage" of a new or modified source's increased emission), and 182(c)(6) (setting a limit of 25 tons when aggregated with all other net increase in emission from the source over any period of 5 consecutive years).

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[126] *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).

[127] *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; 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.

However, none of the cited provisions constrains EPA's discretion as each provision deals with a relatively narrow applicability issue that does not touch on how EPA determines what sources have been modified. In fact, that Congress specified a particular time frame in these provisions demonstrates that the legislature knew how to focus NSR provisions on annual emissions when it desired. By not including a specific time frame, Congress chose not to define modification further. Each provision was adopted after EPA had developed a body of regulations interpreting section 111(a)(4) to support an hourly emission increase test, and Congress did not demonstrate any intent to do away with that interpretation when adopting these new regulations. In particular, section 182(c)(6), addresses how EPA may decide what emission increases qualify as de minimis in severe ozone nonattainment areas, but it does not suggest that EPA cannot combine an hourly emission-based "modification" test with a "significant net emissions increase" test that uses de minimis thresholds based on annual emission.[128]

Previous commenters claimed that modification for PSD purposes must be based on annual emissions because of the CAA's connection between the PSD preconstruction permitting program and the protection of air quality increments. However, PSD increments are not just expressed as annual averages: they are also expressed in terms of 24-hour and 3-hour maximums that may be better protected by an hourly emission increase test. Moreover, the CAA does not require that all emission increases that might consume some portion of the PSD increment in an area undergo preconstruction permitting. The D.C. Circuit recognized in *Alabama Power* that PSD permitting is not "the exclusive mechanism" for monitoring increment consumption,[129] and the CAA imposes an independent obligation on states to "assur[e] that maximum allowable

[128] CAA § 182(c)(6).

[129] 636 F.2d at 362.

increases over baseline concentrations of, and maximum allowable concentrations of, [applicable] pollutant[s] shall not be exceeded."[130]

C. APPA Supports Adopting the Hourly Emissions Rate Increase Test as Step 2 of the NSR Applicability Analysis for Existing EGUs.

EPA has proposed to pair the new hourly emissions increase test for modifications with its current annual emission increase test for major modifications.[131] Under the proposed rule, the hourly emissions increase test would become "Step 2" of a four-step NSR applicability analysis for existing EGUs.[132] APPA agrees that EPA should adopt the hourly emissions test to determine whether a physical or operational change constitutes "modification" before proceeding to determine whether it is also a "major modification" using the current significant net emissions increase test.

This multi-layered approach has also received some support by the Supreme Court. In *Environmental Defense v. Duke Energy Corp.*, the Court observed that interpreting "modification" to include both an hourly and annual emission increase as "set to subset" "sounds right," but was not supported by the regulatory text as written.[133] Here, EPA *is* proposing to revise the regulatory text.

Moreover, any attempt to eliminate netting by EPA would be highly suspect under the D.C. Circuit's long-standing decision in *Alabama Power*. In that case, the court held "[w]here there is no net increase from contemporaneous changes within a source, . . . PSD review, whether procedural or substantive, cannot apply."[134] Therefore, retaining the current "major

[130] CAA § 163(a).

[131] 83 Fed. Reg. at 44,780; *id.* at 44,798, 44,801 (Proposed 40 C.F.R. §§ 51.167(c), 52.25(c)).

[132] *Id.* at 44,780.

[133] 549 U.S. 561, 581 n.8 (2007).

[134] 636 F.2d at 403.

modification" analysis as component of a multi-step process to determine NSR applicability comports with the *Alabama Power* ruling.

D. If EPA Adopts Alternative 1 or 2, It Must Account for the Causal Link Requirements and Revise Its Proposed Approaches for Comparing Pre-and Post-Project Emissions.

Section 111(a)(4) requires that a causal link exist between the physical or operational change and the resulting emissions increase for a source to be modified. A test based on comparing maximum achievable pre- and post-project emissions adequately accounts for causation because it necessarily compares emission under comparable conditions (i.e., at maximum output).

However, both Alternative 1 and 2 (i.e., EPA's proposed "maximum achieved" tests) fail to adequately account for causation. These proposed tests simply compare emissions before and after a project and assume that any increase results from the project. This fails to take into account the possibility of an EGU observing higher hourly emission in the post-project period for a myriad of reasons wholly unrelated to the project, such as, a change in the sulfur content of coal, variability in the operation of control technologies, variability related to load changes in ambient conditions, or normal inherent variability in emissions measurement.

There are two possible ways for EPA to incorporate the required causal connection in establishing a maximum hourly emissions test: (1) require a comparison of maximum hourly emissions before and after the project under the same representative conditions; or (2) exclude from actual post-project maximum hourly emissions any increases that are caused by factors that are independent from the project.

Additionally, APPA believes that EPA's proposed statistical test for comparing maximum achieved emissions is flawed for several reasons. First, in the proposed method, the upper tolerance limit (UTL) would be calculated based on hourly emission rates reported in the

CEMS during the highest 10% of yearly operating hours in the baseline period, sorted by heat input, and not emissions.[135,136] Under this method, it is possible that the UTL will not be calculated based on the source's highest hourly emissions. If EPA adopts a method based on Alternative 1, it must, as a minimum, base the UTL for emissions directly measured by CEMS on to the top 10% (or higher percentage) based on emissions, not heat input.

More fundamentally, the statistical method is flawed because it compares a statistical measure of a unit's performance in the baseline to the unit's performance during *every hour* of operation after a project.[137] In the 2007 Proposal, EPA explained that under the proposed 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."[138] By the same token, one would also necessarily expect that 0.1 percent of the hourly emissions data would exceed the UTL—even if the source's emissions do not change at all. Therefore, the proposed statistical method is likely to yield "false positives"—identifying a project as a modification even if there is no change in emissions. As to Alternative 2, comparing the single maximum hourly emissions measured in a CEMS before and after the project is also flawed because such emissions may not be representative.

EPA's proposed language specifying the "data limitations for maximum emission rates"[139] requires revision to be consistent with the definition of "out-of-control" periods and

[135] 83 Fed. Reg. at 44,799, 44,801 (Proposed 40 C.F.R. §§ 51.167(f)(1)(i)(C) Alternative 1, 52.25(f)(1)(i)(C) Alternative 1).

[136] Specified hours of data are excluded, bringing the percent of operating hours used for the analysis to less than 10 percent.

[137] Specified hours of data are excluded, bring the percent of operating hours used for the analysis to less than 10 percent.

[138] 72 Fed. Reg. at 26,215.

[139] 83 Fed. Reg. at 44,800, 44,803 (Proposed 40 C.F.R. §§ 51.167(f)(1), (2) Alternative 3, 52.25(f)(1), (2) Alternative 3).

data validation criteria in other rules and to otherwise clarify what data should be excluded from the required calculations.

XV. Conclusion

The Association appreciates the opportunity to provide these comments and recommends them for consideration in the final emission guideline, implementing regulations and NSR program reforms. These suggested revisions will ensure that the ACE Rule is workable for affected sources and that the emission guideline and the implementing regulations better align with the requirements in the CAA while ensuring improved efficiency and reduced CO_2 emissions from affected units. Please contact Ms. Carolyn Slaughter, Director of Environmental Policy at cslaughter@publicpower.org or (202) 467-2943 with questions regarding these comments.

APPENDIX A

PRELIMINARY SUMMARY: HEAT RATE IMPROVEMENT IMPACT ON SELECT PUBLIC POWER UNIT

Prepared for

APPA

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October 29, 2018

APPROACH TO EVALUATE HRI COSTS, IMPACT

- HRI Cost Approach
  - Source: EPA-defined cost and performance data in proposed rule (Tables 1, 2)
  - Use Owner-specified cost, benefit where available
  - Otherwise: Use minimum cost, payoff as most Owners have typically routinely deploy these actions
  - Capital recovery: 15 Yrs @ 0.126 (hardware), and 5 yrs @0.228 (software)
- Impact on 2017 Generation Costs
  - Based upon Fuel and Variable O&M
  - Computed 2017 Unit Fuel and Variable O&M Costs ($/MWh)
  - Estimated 2017 Unit Fuel Savings ($/MWh) from all HRI
  - Determined the Impact (Reduction) on Unit 2017 Generation Costs ($/MWh)

DATA SOURCES TO DETERMINE 2017 UNIT GENERATION COSTS

- Fuel Cost: 2017 Form EIA 923: Fuel Receipts, Costs
- Fuel Consumption: 2017 Form EIA 923: Boiler Fuel Data
- Generation: 2017 Form EIA 923: Unit Generator Data
- Variable O&M
  - Documentation of EPA Power Sector Modeling Platform v6 Based on Integrated Planning Model (May 2018)
- Follow-up with individual Public Power utilities

SELECTED SEVEN PUBLIC POWER UNITS FOR EVALUATION

- MW_Bit_10Y_SCR_wFGD – Midwest unit burning bituminous coal around 10 years old with a SCR and wFGD
- MW_Sub_30Y_SCR_dFGD – Midwest unit burning subbituminous coal >30 years old with a SCR and dFGD
- SE_Bit_30Y_SCR_wFGD- Southeast unit burning bituminous coal >30 years old with a SCR and wFGD
- SE_Bit_20Y_SCR_wFGD – Southeast unit burning bituminous coal >20 years old with a SCR and wFGD
- MW_Sub_30Y_wFGD – Midwest unit burning subbituminous coal >30 years old with a wFGD
- MW_Sub_30Y_no_SCRFGD – Midwest unit burning subbituminous coal >30 years old with no SCR or FGD
- MW_Sub_10Y_SCR_dFGD – Midwest unit burning subbituminous coal around 10 years old with a SCR and dFGD

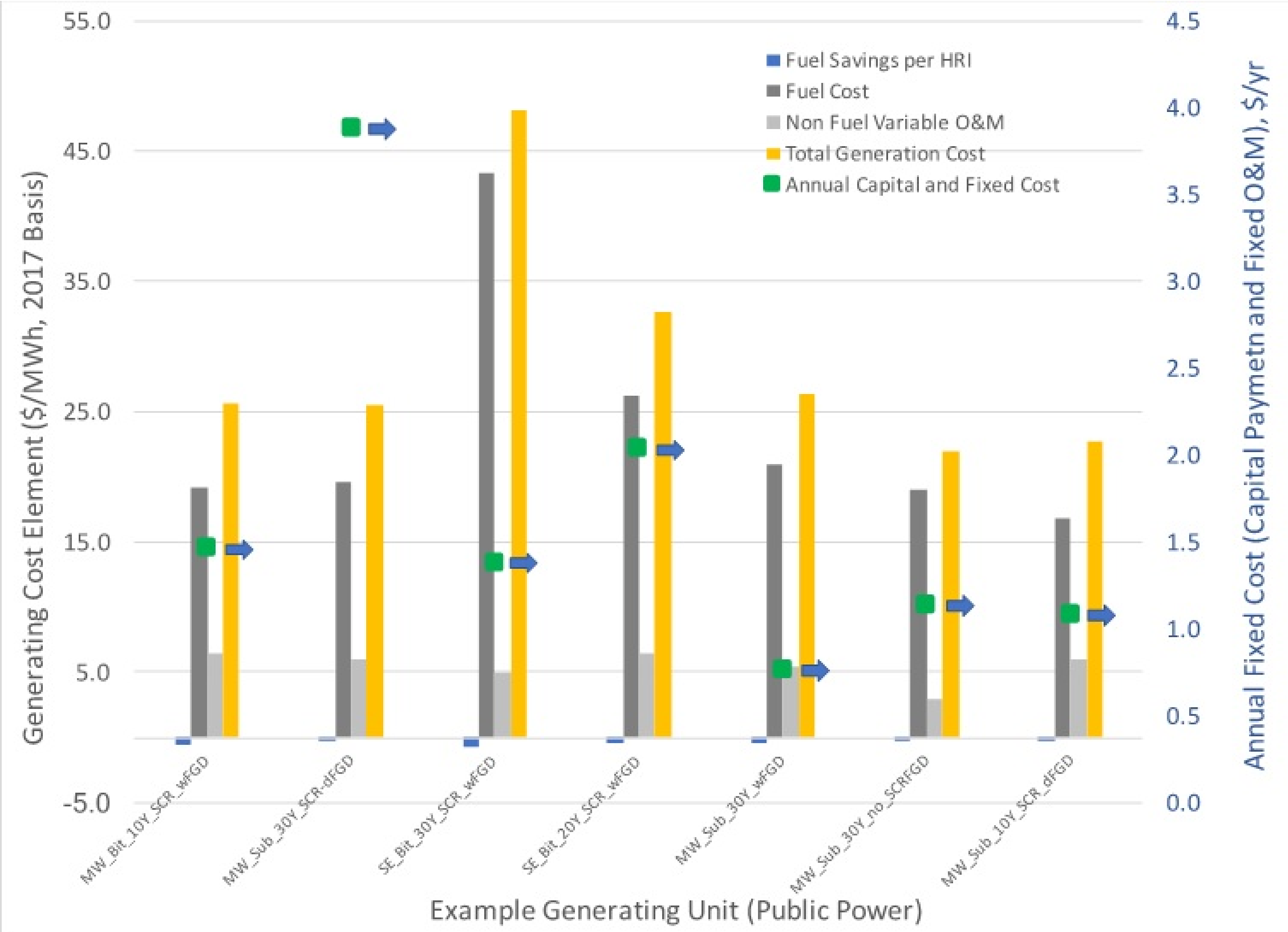
COST, HRI IMPROVEMENTS INPUTS (1)

	MW_Bit_10Y_ SCR_wFGD		MW_Sub_30Y_ SCR_dFGD		SE_Bit_30Y SCR_wFGD		SE_Bit_20Y_SCR wFGD	
	Capital/ O&M ($)	HRI (%)	Capital/ O&M ($)	HRI (%)	Capital/ O&M ($)	HRI (%)	Capital/ O&M ($)	HRI (%)
NN/ISB	0.70M/ 50K	0.3	0.63M/ 50K	0.3	0.78M/ 50K	0.3	1.16M/ 50K	0.3
Boiler Feed	0.50M	0.2	0.35M	0.2	0.34M	0.2	0.51M	0.2
Air Ingress	0.75M/ 75K	0.05	0.65M/ $75K	0.05	0.79M/ 75K	0.1	1.16M/ 75K	0.1
VFD	2.0M/ 30K	0.2	5.2M/ 30K	0.2	2.27M/ $30K	0.2	3.34M/ 30K	0.2
Steam Path	15M	0.5	20.5M	0.5	2.80 M	0.5	4.13M	0.5
Boiler Eco	2.94M/ 100K	0.25	2.74M/ 100K	0.25	3.31 M/ 100K	0.25	4.87M/ 100K	0.25
O&M	40K	0.05	$40K	0.1	40K	0.1	40K	0.1

COST, HRI IMPROVEMENTS INPUTS (1)

	MW_Sub_30Y wFGD		MW_Sub_30Y no_SCRFGD		MW_Sub_10Y SCR_dFGD	
	Capital/ O&M ($)	HRI (%)	Capital/ O&M ($)	HRI (%)	Capital/ O&M ($)	HRI (%)
NN/ISB	0.44M/ 50K	0.3	0.65M/ 50K	0.3	0.62M/ 50K	0.3
Boiler Feed	0.19M	0.2	0.28M	0.2	0.29M	0.2
Air Ingress	0.44M/ 75K	0.10	0.65M/ 75K	0.10	0.62M/ 75K	0.1
VFD	1.26M/ 30K	0.2	1.88M/ 30K	0.2	1.78M/ 30K	0.2
Steam Path	1.56M	0.5	2.3M	0.5	2.20 M	0.5
Boiler Eco	1.84M/ 100K	0.25	2.74M/ 100K	0.25	2.60M/ 100K	0.25
O&M	40K	0.10	40K	0.1	$40K	0.1

COMPARISON OF COST METRICS: HRI on SEVEN PUBLIC POWER UNITS



SUMMARY OF UNIT COST IMPACTS

Unit	Annual Capital, Fixed Operating Cost ($M/yr)	2017 Fuel Cost ($/MWh)	2017 Variable O&M Cost ($/MWh)	2017 Total Generation Cost ($/MWh)	Reduction in Fuel Cost ($/MWh)
MW_Bit_10Y_ SCR_wFGD	1.47	19.16	6.39	25.55	-0.53
MW_Sub_30Y SCR_dFGD	3.88	19.55	5.93	25.48	-0.31
SE_Bit_30Y SCR_wFGD	1.38	43.24	4.91	48.15	-0.66
SE_Bit_20Y SCR_wFGD	2.03	26.24	6.39	32.63	-0.45
MW_Sub_30Y wFGD	0.77	20.91	5.43	26.34	-0.38
MW_Sub_30Y no_SCRFGD	1.14	19.06	2.90	21.96	-0.28
MW_Sub_10Y SCR_dFGD	1	16.79	5.93	22.72	-0.24

IMPACT OF HRI ON 2017 GENERATION COSTS

Unit	2017 Generation Cost ($/MWh)	Reduction in Fuel Cost ($/MWh)	HRI Generation Cost ($/MWh)	Percent Change (%)
MW_Bit_10Y SCR_wFGD	25.55	-0.53	25.03	-2.1
MW_Sub_30Y SCR_dFGD	25.48	-0.31	25.17	-1.2
SE_Bit_30Y SCR_wFGD	48.15	-0.66	47.50	-1.4
SE_Bit_20Y SCR_wFGD	32.63	-0.45	32.18	-1.4
MW_Sub_30Y wFGD	26.34	-0.38	25.96	-1.4
MW_Sub_30Y no_SCRFGD	21.96	-0.28	21.68	-1.3
MW_Sub_10Y SCR_dFGD	22.72	-0.24	22.48	-1.0

SUMMARY OF FINDINGS

- EPA identified HRI actions would reduce 2017 unit generation costs between 1 and 2 percent
- Fuel savings is small compared to total Generation Cost
- HRIs would allow these units to remain competitive in their RTOs unless there is a significant change in their load
- Large capital cost is required to derive small-modest benefits
- Benefits could be outweighed by
  - Operation at lower loads
  - Compromise of HRI benefit with time