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INSTITUTE

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October 31, 2018

The Honorable Andrew Wheeler
Acting Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Dear Acting Administrator Wheeler:

The Edison Electric Institute (EEI) appreciates the opportunity to provide the attached comments to the U.S. Environmental Protection Agency (EPA) regarding the proposed Affordable Clean Energy (ACE) rule (Docket No. EPA-HQ-OAR-2017-0355). 83 *Fed. Reg*. 44,746 (Aug. 31, 2018).

EEI is the association that represents all U.S. investor-owned electric companies. Our members provide electricity for about 220 million Americans and operate in all 50 states and the District of Columbia. As a whole, the electric power industry supports more than 7 million jobs in communities across the United States.

EEI's comments focus on the power sector's continued transition to cleaner sources of energy, and the necessity, both from a legal and operational perspective, that any final section 111(d) guidelines take into account the ongoing clean energy transition by providing states and sources with significant flexibility when determining compliance measures. EEI members are committed to this customer-focused transition, investing significant capital in the energy grid to make it smarter, cleaner, more dynamic, more flexible and more secure in order to integrate additional distributed energy resources and deliver a balanced mix of resources to customers.

EPA must provide states with flexibility in establishing compliance plans with any final section 111(d) guidelines to facilitate the clean energy transition, and should encourage states to use whatever flexibilities best address technical and operational factors. If you have questions about these comments, please contact Alex Bond (abond@eei.org; 202-508-5523) or Eric Holdsworth (eholdsworth@eei.org; 202-508-5103).

Sincerely,

Quinlan J. Shea, III

cc: Bill Wehrum, Assistant Administrator, Office of Air and Radiation
Mandy Gunasekara, Deputy Assistant Administrator, Office of Air and Radiation
Ryan Jackson, Chief of Staff, Office of the Administrator
Peter Tsirigotis, Director, Office of Air Quality Planning and Standards
Dr. Nick Hutson, Energy Strategies Group

Attachments

COMMENTS OF THE EDISON ELECTRIC INSTITUTE ON THE ENVIRONMENTAL PROTECTION AGENCY'S PROPOSED EMISSION GUIDELINES FOR GREENHOUSE GAS EMISSIONS FROM EXISTING ELECTRIC GENERATING UNITS; REVISIONS TO EMISSIONS GUIDELINE IMPLEMENTING REGULATIONS; REVISIONS TO NEW SOURCE REVIEW PROGRAM

EPA-HQ-OAR-2017-0355

October 31, 2018

The Environmental Protection Agency (EPA or Agency) proposes three separate actions that have implications for existing coal-based and other electric generating units (EGUs or units): 1) replacement of the Clean Power Plan (CPP) with the Affordable Clean Energy (ACE) rule to address greenhouse gas (GHG) emissions under Clean Air Act (CAA or Act) section 111(d); 2) corresponding clarifications of the existing section 111(d) implementing regulations as well as new section 111(d) implementing regulations; and 3) amendment of the New Source Review (NSR) regulations to include an hourly emissions increase test for EGUs. 83 *Fed. Reg*. 44,746 (Aug. 31, 2018).

The Edison Electric Institute (EEI) is the association that represents all U.S. investor-owned electric companies. Our members provide electricity for about 220 million Americans and operate in all 50 states and the District of Columbia. As a whole, the electric power industry supports more than seven million jobs in communities across the United States. EEI members own and operate coal-based EGUs that would be regulated under ACE, as well as other EGUs that work in tandem with these affected units to provide affordable, reliable electricity to customers. EEI members also would be affected by changes to the section 111(d) implementing regulations and the proposed changes to the NSR regulations.

Driven by a number of factors—including customer demands, technology developments, and federal and state regulatory obligations—the electric sector is undergoing a transition that will continue over the next decade and beyond. Concurrent with this transition, EEI member companies are investing significant amounts of capital—more than 113 billion dollars in 2017 alone—to make the energy grid smarter, cleaner, more dynamic, more flexible, and more secure in order to integrate and deliver a balanced mix of resources from both central and distributed energy resources to customers. The electric sector continues to invest in a range of 24/7 energy sources and other technologies, so that the sector can reduce GHG emissions faster, and bring the benefits of clean, reliable, and affordable energy to everyone.

This transformation has technical and operational impacts across the power sector, driving concerns about the implementation of EPA's three proposed actions, particularly the development, implementation and enforcement of unit-specific GHG performance standards and compliance plans by the states. EPA must consider this transformation if the Agency finalizes these proposals and provide EGU owners and operators and states significant compliance flexibility, consistent with the requirements of the Act.[1] Failure to provide such flexibility has the potential to undermine not only the clean energy transition by increasing costs for electricity

[1] EPA asserts that the Agency "proposes *possibly* to replace the CPP" with the ACE rule. *See* 83 *Fed. Reg*. at 44,748 (emphasis added). EPA also notes that the three proposals are "appropriate policies in their own right and on their own terms" and "would be severable…on judicial review" and seeks comments as to whether to finalize the NSR revisions, in particular, in a separate action. *See id*. at 44,783. In these comments, the discussion of these three proposals and their possible finalization in some future action, EEI is not taking a position on these issues. The desirability of finalizing the proposed NSR revisions in a separate action are discussed in more detail in section VI(C), *infra*.

customers, but also EPA's proposed ACE rule itself, by increasing the economic burdens imposed on the remaining existing coal-based EGU fleet.

I. Executive Summary.

EEI's comments on the proposed ACE rule, the proposed clarifications and changes to the CAA section 111(d) implementing regulations and the proposed amendment of the NSR program are focused on two areas: 1) the power sector's continued transition to cleaner sources of energy; and 2) the necessity, both from a legal and operational perspective, that any final CAA section 111(d) guidelines take into account the ongoing clean energy transition by providing states and sources with significant flexibility when determining compliance measures. EEI's comments center on the importance of ensuring a wide range of compliance options and the role of states in designing standards of performance and implementing state plans.

Electric companies are committed to delivering clean energy to customers and are leading the clean energy transition. EEI members are investing significant capital in the energy grid to make it smarter, cleaner, more dynamic, more flexible and more secure to allow for the integration of additional distributed resources into the balance mix of resources they deliver. As a result, total power sector GHG emissions were 28 percent below 2005 levels at the end of 2017 and are projected to continue to decrease into the next decade.[2] These expected future reductions are bolstered by voluntary emissions reductions commitments offered by more than 30 of EEI's member companies, many of which pledge to reduce GHG emissions by 80 percent or more

[2] *See* EIA, *Monthly Energy Review*, Table 7.2b (Oct. 2018), https://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.

below 2005 levels by 2050, and/or contain significant reductions pledged for 2030 and 2040 as well.[3] These reductions are driven by a range of factors, including the historically low price of natural gas, the declining costs of renewable generation, customer preferences and other regulatory requirements. While the CPP was stayed by the Supreme Court in 2016, the power sector will have complied with the final 2030 goals of the rule—in terms of gross emissions reductions—before the 2022 start date included in that program.

Given this fleet transition, it is therefore important to provide not only states with flexibility to develop emissions standards of performance, but also significant flexibility to states and sources in establishing compliance plans for affected units. EPA should take into consideration important operational and technical realities of EGU operation, such as the variability of each unit's emissions and the degradation of heat rate improvements (HRI) over time, when determining its approach to the range of compliance options that states can include in plans. In addition, the Agency should provide more detailed, but not prescriptive, guidance to states on how to set standards and support compliance flexibility. Importantly, EPA should make clear that the Agency is not dictating that states must use a particular compliance mechanism, and that EPA is not preemptively determining that any potential flexibilities for compliance are invalid, including averaging, trading, and altering the form of the standard. Failure to provide such compliance flexibility to states has the potential to undermine the on-going clean energy transition by increasing the cost of electricity for customers and increasing economic burdens on the existing coal-based fleet.

[3] *See* Appendix A, which lists these voluntary public commitments.

Additionally, EPA should clarify the applicability of the proposed ACE rule, as well as certain parts of the alterations to the implementing regulations.

II. Electric Power Companies Continue to Lead the Clean Energy Transition.

The electric power industry is in the middle of a profound, long-term transformation in how electricity is generated, transmitted, and used. This transformation is being driven by a wide range of factors, including: declining costs for natural gas and renewable energy resources, technological improvements, changing customer expectations, various federal and state regulations and policies, and the growth of distributed energy resources.

Customers throughout the country believe that the way energy is used and produced is changing, and they want more control over the energy they use. Customers are excited about innovation and are paying attention to what is coming next. Most importantly, they expect our industry to be at the center of change and to deliver the energy future they want, in ways that enhance reliability and affordability. To meet customers' changing needs, the electric power industry is transitioning to cleaner generation sources and leading the way on renewables and next-generation nuclear power, while ensuring that existing clean energy resources are available now and in the future.

Electric companies are focused on leading this clean energy transition on a fleetwide basis and doing it in an affordable way that maintains system reliability. Based on data from the Department of Energy's Energy Information Administration (EIA) and adjusting for inflation using the Consumer Price Index (CPI), the average price of electricity (in real 2005 $) was 8.6

cents per kWh in 2007 and 8.4 cents per kWh in 2017.[4] This transition can power the country in a way that is good for our economy, good for our health and the environment, and responsive to the needs of our customers for reliable, affordable, and increasingly clean energy sources.

A. Electric Companies Are Committed to Clean Energy for Customers.

As noted above, more than 30 EEI member companies have announced a variety of short-, mid- and long-term GHG reduction goals over the coming decades. many of which pledge to reduce GHG emissions by 80 percent or more below 2005 levels by 2050, and/or contain significant reductions pledged for 2030 and 2040 as well.[5] Since 2014, more than half of the industry's investments in new electricity generation have been in wind and solar generation resources. As a result, the use of renewable energy to generate electricity is projected to almost quadruple between 2010 and 2040 even without additional policy intervention.[6] In addition, the industry is building smarter energy infrastructure, and these investments are creating additional jobs and making the energy grid more dynamic and more secure for all customers. Electric power companies also are investing in energy efficiency and providing customers the energy solutions they want, while partnering with leading innovative companies and start-ups to shape the future using technology. Thus, this transition is poised to continue going forward.

[4] EEI internal analysis based on EIA's *Electric Power Annual 2017*, Table 2.4 (Oct. 2018), https://www.eia.gov/electricity/annual/pdf/epa.pdf. Note that information on retail electricity prices in nominal dollars can be found in table 2.4 and that information on the CPI is provided by the Bureau of Labor Statistics, https://data.bls.gov/pdq/SurveyOutputServlet.

[5] *See* Appendix A.

[6] *See* EIA, *Today in Energy, Nearly half of utility-scale capacity installed in 2017 came from renewables* (Jan. 10, 2018), https://www.eia.gov/todayinenergy/detail.php?id=34472.

B. GHG and Criteria Pollutant Emissions Have Declined Considerably and Electric Companies Have Significantly Increased Deployment of Clean Energy Technologies; the Proposed Rule Does Not Assist This Transition.

The mix of resources used to generate electricity in the United States has changed dramatically over the last decade and is increasingly clean. Natural gas surpassed coal as the main source of electricity generation in the United States for the second year in a row in 2017, with natural gas-based generation powering 32 percent of the country's electricity, compared to coal-based generation at 30 percent.[7]

In addition, according to the EIA, today more than one-third of U.S. electricity comes from zero-carbon energy sources, including nuclear energy, hydropower and other renewables.[8] The electric power industry is leading the development of zero-carbon energy sources, including renewable energy. For example, the industry provides virtually all the wind, geothermal, and hydropower electricity—and, electric companies own 62 percent of all solar capacity—in the country.[9] Our universal (or large-scale) solar projects accounted for 59 percent of installed capacity in 2017.[10] The industry is also leading the way on energy storage and uses or contracts for more than 90 percent of all storage.

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[7] *See* EIA, *Electricity Explained: Electricity in the United States* (Apr. 2018), https://www.eia.gov/energyexplained/index.php?page=electricity_in_the_united_states.

[8] *See* EIA, n.2, *supra*.

[9] *See* Solar Energy Industries Association, Wood Mackenzie, Limited: Solar Market Insight Report 2018 Q3, https://www.seia.org/research-resources/solar-market-insight-report-2018-q3.

[10] *See Id*.

Driven by these changes, the power sector has significantly reduced its emissions. According to EIA, as of the end of 2017, power sector CO_2 emissions were 28 percent below 2005 levels.[11] Investor-owned electric companies alone have reduced emissions by 35 percent below 2005 levels as of the end of 2017,[12] essentially surpassing the nation-wide carbon dioxide (CO_2) reductions that EPA estimated would have been achieved by the CPP—now proposed for rescission—*four years before the CPP's first compliance period was to begin*.

As a result of these reductions, the transportation sector surpassed the electric power sector as the leading domestic source of CO_2 emissions, starting in 2016. That trend continued in 2017, with the transportation sector emitting 37 percent of U.S. CO_2 emissions, while the power sector emitted 34 percent.[13] As EPA notes in the proposed rule, the cumulative effect of these on-going changes is a reduction in the projected share of CO_2 emissions from electric generators, even without the CPP. "In other words, these declining emission trends have continued to develop even in the absence of implementation of the CPP." 83 *Fed. Reg*. at 44,751.[14]

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[11] *See* EIA, n. 2 at Table 12.6, *supra*, https://www.eia.gov/totalenergy/data/monthly/pdf/sec12_9.pdf.

[12] Based on an EEI analysis of CO_2 emissions data from ABB Velocity Suite.

[13] *See* EIA, n.2, *supra*, at Tables 12.1, 12.5, and 12.6, https://www.eia.gov/totalenergy/data/monthly/pdf/sec12_3.pdf; https://www.eia.gov/totalenergy/data/monthly/pdf/sec12_8.pdf; and, https://www.eia.gov/totalenergy/data/monthly/pdf/sec12_9.pdf.

[14] In addition to CO_2 reductions, between 1990 and 2017, power sector emissions of nitrogen oxides (NO_x) were cut by 84 percent and sulfur dioxide (SO_2) emissions by 92 percent—a period when electricity use grew by 35 percent, helping to reduce ozone, particulate matter and haze. Data compiled from EIA, EPA, and the U.S. Bureau of Economic Analysis.

EPA had previously estimated that the CPP would lead to an average reduction of GHG emissions of 32 percent below 2005 levels by 2030.[15] In the Regulatory Impact Analysis (RIA) accompanying the ACE proposal, EPA estimates that this proposed rule will lead to some additional reductions when compared to the repeal of the CPP. "Relative to a projected future without CPP, the illustrative policy scenarios are projected to result in an annual CO_2 emissions decrease of, at most, two percent in 2025-2035. Additionally, EPA projects a 2030 CO_2 emissions decrease of 35 percent below 2005 levels for the base case (CPP) and 33 percent below 2005 levels for each of the illustrative policy scenarios under the ACE proposal." RIA at 3-14. Similarly, EPA has indicated that its analysis for the ACE Rule suggests "that, when states have fully implemented the ACE rule, U.S. power sector CO_2 emissions could be around 34 [percent] below 2005 levels."[16] However, those projected reductions have largely already been achieved due to the on-going fleet transition described above.

The CO_2 emissions reductions achieved by the power sector have occurred as the result of a range of different, and occasionally overlapping, reasons. According to the EIA, two basic contributing factors that led to the cumulative reduction of more than 3,800 million metric tons of CO_2 over the last decade were "the substitution of coal-fired generation with the less-carbon-intensive and more efficient combined-cycle natural gas-fired generation and the growth in non-carbon electricity generation, especially from wind and solar."[17] Factors cited in an analysis

[15] EPA, *Clean Power Plan Fact Sheet* (Aug. 2015), https://archive.epa.gov/epa/cleanpowerplan/fact-sheet-clean-power-plan-numbers.html#print.

[16] EPA, Fact Sheet: Proposed ACE Rule – CO_2 Emissions Trends.

[17] *See* EIA, *U.S. Energy-Related Carbon Dioxide Emissions, 2017,* at 12 (Sept. 2018).

published by The Energy Collective Group include coal-to-natural gas fuel switching, natural gas-to-wind and solar power displacement, increased generation from renewable generation and reduced demand for net generation.[18] EPA itself acknowledges this in the proposed rule when noting that "all of these trends, in total, are expected to result in declining power sector CO_2 emissions." 83 *Fed. Reg.* at 44,751.

III. EPA's Proposed BSER Necessitates That States Be Provided Significant Flexibility In Establishing Emissions Standards And Compliance Plans For Existing Coal-Based EGUs.

EPA proposes to identify HRI as the Best System of Emission Reduction (BSER) for existing steam generating fossil fuel-fired EGUs, which are measures that can be applied at an affected unit. *See id.* at 44,748. EPA finds that this BSER is consistent both with the authority provided the Agency under CAA section 111(d) and with what is technically feasible and appropriate for affected coal-based generation. *See id.* at 44,749. Once EPA determines BSER, consistent with the requirements of CAA section 111(d)(1), states are to determine standards of performance for affected units. *See id.* at 44,755. According to EPA, "states have considerable flexibility in determining the emissions standards for units." *Id.* at 44,763.

While EPA recognizes states' considerable flexibility when setting performance standards for affected units, EPA's proposed approach to the range of compliance options that states can provide affected units is too prescriptive: EPA proposes to limit compliance options for states and units to only those that can be applied and measured at the unit level in a very specific

[18] *See* John Miller, The Energy Collective Group, *What Major Factors Reduced U.S. Power Sector Carbon Emissions 2007-2017?* (Feb. 2018), https://www.energycentral.com/c/ec/what-major-factors-reduced-us-power-sector-carbon-emissions-2007-2017.

form.[19] *See id*. at 44,765. EPA must provide states and affected units with a broader range of compliance flexibilities. Specifically, EPA should decline to limit potential compliance flexibility in any final ACE rule. Instead, EPA should encourage states to use whatever flexibilities best address state and local technical and operational factors. EPA can evaluate these flexibilities in the context of its review of state plans.

A. EPA's BSER and Approach to Compliance Flexibility Ignores Important Technical Considerations and the Variability of Each EGU's Emissions.

In determining BSER, EPA proposes a menu of HRI projects that states must evaluate to determine an emission standard for an affected unit. In approaching BSER in this way, EPA explicitly recognizes unit variability, noting that each unit has unique characteristics that reflect that each was designed to meet local and regional electricity needs, and that geography, elevation, unit size, pollution controls, firing method and utilization rates are all factors that can affect the efficiency and performance of a unit. *See id*. at 44,755. However, while EPA's recognition of unit variability—the different factors that affect heat rate at a unit—and the diverse nature of the coal-based fleet is appropriate when setting BSER, in limiting compliance flexibility EPA fails to recognize the different heat rate/emissions rates that can be achieved by units over time and that the differences between units not only affect which HRI projects may be implemented at a unit, they also have significant effect on the actual emissions rates that these units can achieve.

[19] EPA has proposed to allow source-wide averaging, which is consistent with the source-specific BSER.

Put simply, emissions rates vary considerably over time. Further, HRI degrade over time, creating another level of emissions rate variability.[20] These factors may make it difficult for states to establish an emissions standard for an affected unit that can be achieved continuously.

1. Heat Rates Are Not Consistent Over Any Given 24-Hour Period Due to Load Following.

One of the most important factors affecting heat rate is the ramping up and down of a unit in response to load fluctuations. In general, units achieve lower emissions rates at higher and more constant capacity factors. The more fluctuations in generation output, the more fluctuations there will be in emissions performance.[21] While many coal-based units were intended to operate as baseload units, with high and steady capacity factors, the dynamics of the generation mix are changing this. As EEI has pointed out to the Agency in previous comments, many coal units are operating in a load-following role due to the increase of renewable generation and natural gas generation on the system.[22] The increase in load-following behavior has resulted in capacity

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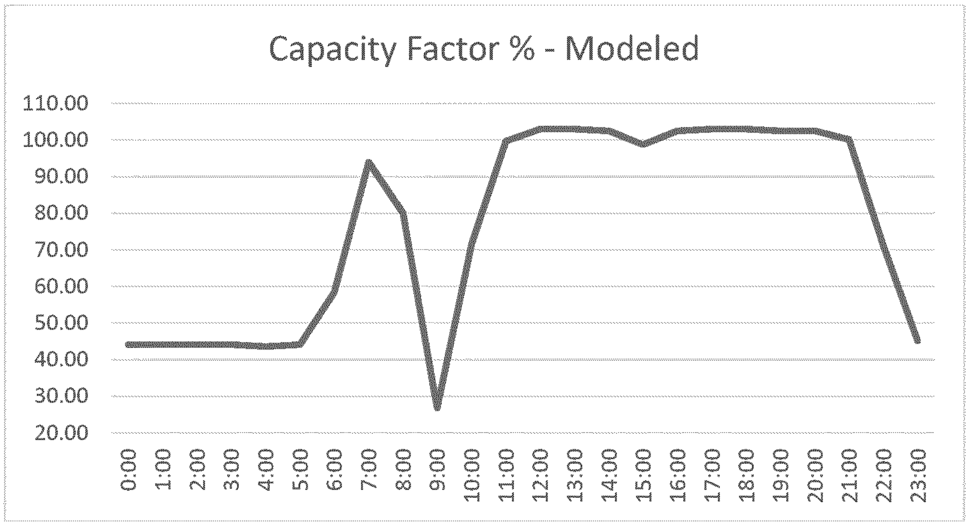
[20] It is even possible that a unit may experience higher average emissions following a HRI project, because its operating profile changes. This does not mean the HRI was not beneficial as, arguably, emissions could have been even higher without the project. But demonstrating the HRI project led to lower emissions may be difficult in some instances, given the range of factors that impact heat rate.

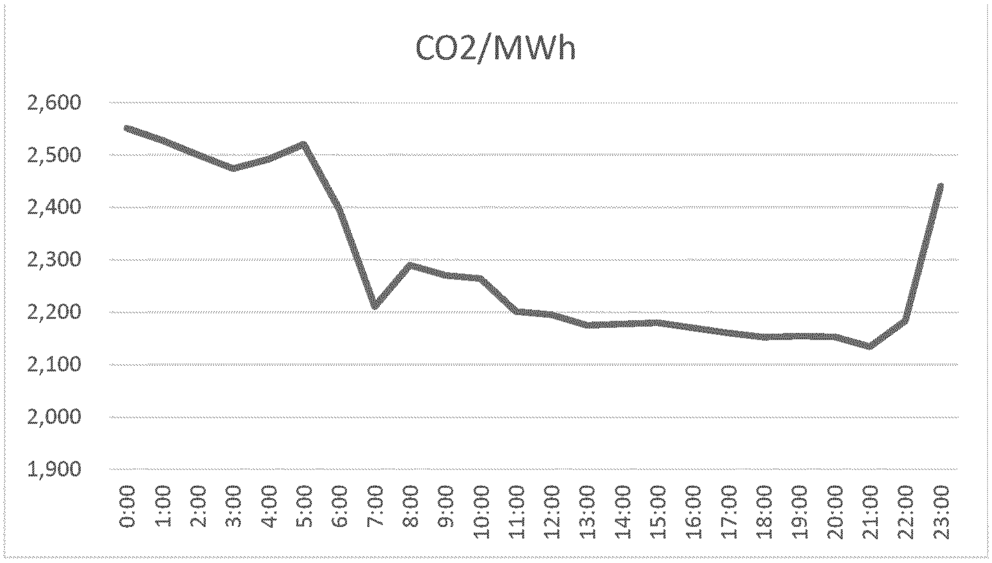
[21] *See* International Energy Agency, *Power Generation from Coal: Measuring and Reporting Efficiency Performance and CO_2 Emissions,* at 19-20 (2010), https://www.iea.org/ciab/papers/power_generation_from_coal.pdf.

[22] *See* Department of Energy, National Energy Technology Lab, *Impact of Load Following on the Economics of Existing Coal-Fired Power Plant Operations*, DOE/NETL-2015/1718 (June 3, 2015)(focusing on cold starts more than ramping, this report also notes that increased cycling requires more fuel and more maintenance, thereby increase the total cost to operate coal units), https://www.netl.doe.gov/energy-analyses/temp/ImpactofLoadFollowingontheEconomicsofExistingCoal-FiredPowerPlantOperations_060315.pdf.

factors and emissions rates with increasing and significant variability.[23] It is not clear how states could set an emissions rate standard that addresses this daily variability. The following figures, which look at emissions from two facilities over one 24-hour period, illustrate the issue:

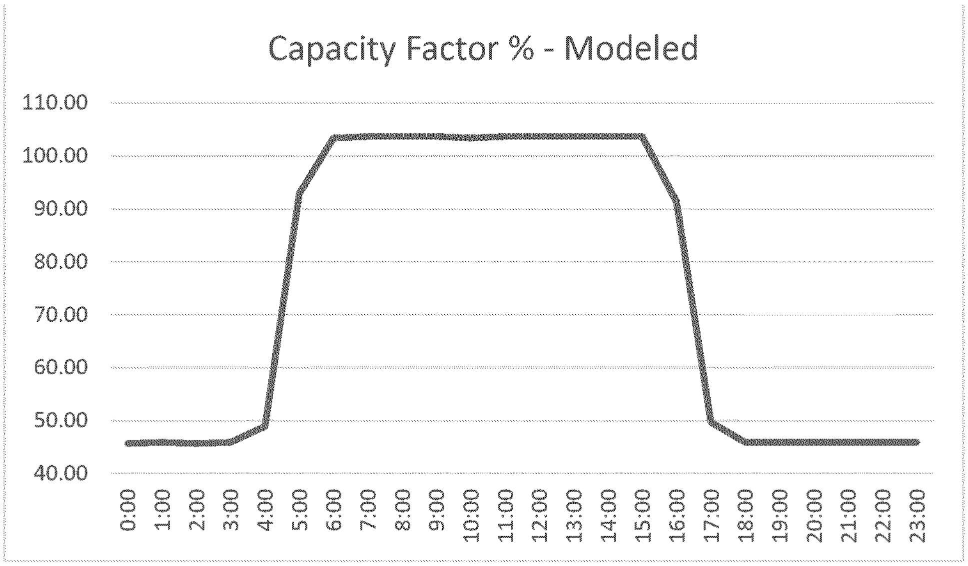
Figures 1 and 2: Coal-Based Unit in PJM, June 6, 2018

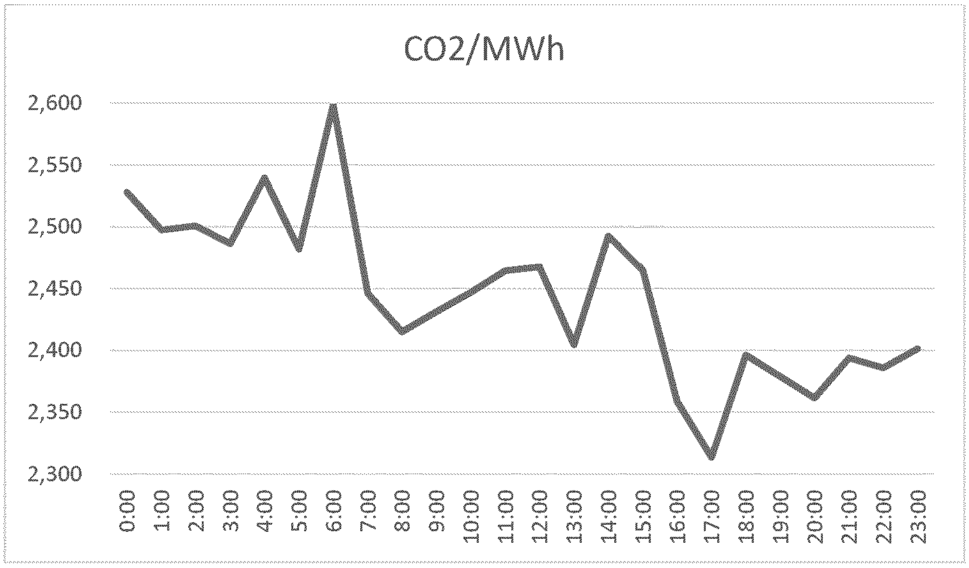




[23] An increase in load-following behavior may reduce total utilization of a coal-based EGU, reducing total CO_2 emissions, but emissions rates would go up.

Figures 3 & 4: Coal-Based Unit in PJM, June 12, 2018

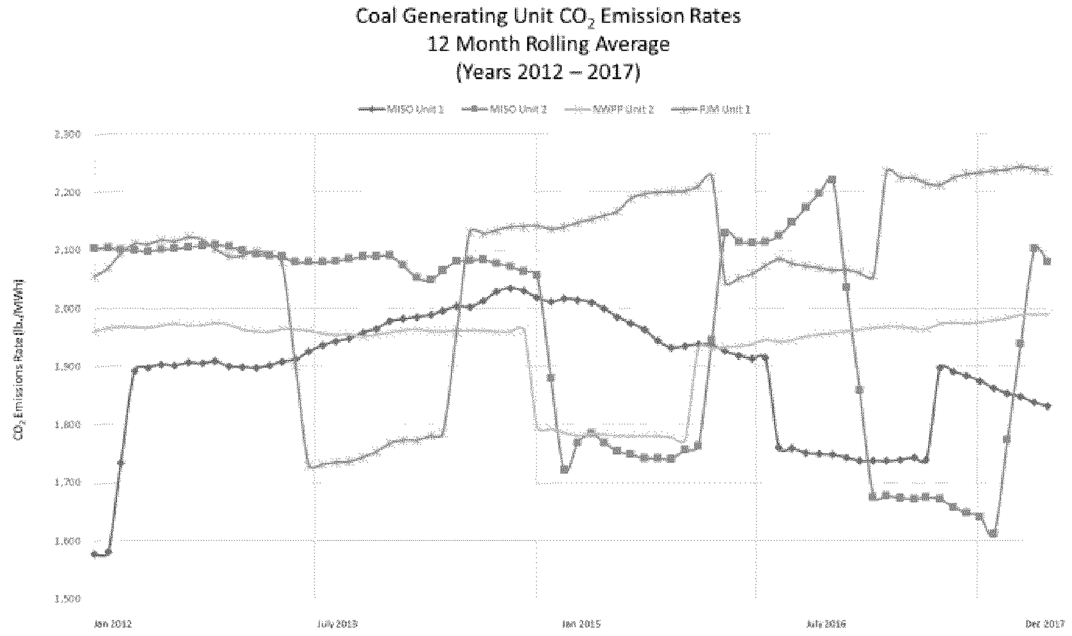




EPA has not addressed this type of emissions variability in the context of establishing BSER. While HRI projects may reduce a unit's rate of CO_2 emissions, these projects will not ameliorate this kind of intraday variability in emissions.

2. Heat Rates Can Be Variable When Measured on an Annual Basis.

Examples of several units within three different balancing authorities charged with maintaining the reliability of the electric grid also highlight the variability of a unit's CO_2 emission rate over time—in this case, when measured over a period of years.



Sources: US EPA CEMS; ABB Velocity Suite

The graph above demonstrates that there are significant changes in a unit's heat rate, not just over a 24-hour period, but when measured over a period of years. While this graph represents the emissions rate of only four units in the larger coal-based generating fleet, there are many coal-based units across the country that operate in a load-following manner, which can impact not only intraday emissions rates, but also emissions rates year-to-year. Accordingly, a particular emissions rate may be achievable one year, but not another, due to the operations of the unit in response to the needs of the larger energy grid, which changes constantly as new resources and new sources of demand are added to the system. It is unlikely that these units would be able to achieve continuous compliance with an emissions rate standard developed by states and included in CAA section 111(d) compliance plans.

3. Heat Rate Improvements are Not Permanent and Will Degrade Over Time.

EPA's approach to BSER in the proposed ACE rule appears to assume that, once implemented, the HRI accomplished by a particular project is permanent. This is not the case. All HRIs deteriorate over time, which has implications for the ability of a unit to achieve an emissions rate in the future that is based on an HRI project.

The Electric Power Research Institute (EPRI) has documented concerns about HRI degradation, noting that all HRI projects have a finite life unless additional efforts (and costs) are made to maintain them.[24] For example, EPRI has noted in this docket, "…replacing the seals in a steam turbine upgrade may provide a ½ percent heat rate improvement upon initial installation. However, under normal operating conditions, that gain will slowly diminish and ultimately disappear after approximately six years. If an upset occurs prior to the of the modification's normal life—for example, a rough plant startup or shutdown—the entire heat rate improvement could be immediately lost."[25] EPA has not addressed how states can set emissions standards that recognize and accommodate this lack of permanence.

B. EPA's Proposed BSER and Proposed Approach to the Standards Do Not Address the CAA Requirement that Emissions Standards Must Be Complied with Continuously.

EPA asserts that the flexibilities provided to states in setting emissions standards will provide for the effective implementation and enforcement of these standards as they apply to particular

[24] Comments of the EPRI filed in Docket No. EPA-HQ-OAR-2017-0355 on Oct. 15, 2018.

[25] *Id.*

affected units. *See* 83 *Fed. Reg*. at 44,765. However, the standard setting flexibilities that EPA identifies may not address the emission variability concerns of all units, as discussed above. Coupled with the lack of meaningful compliance flexibility, EPA's proposed BSER creates significant concerns that the emission standards that states develop may not be achievable on a continuous basis.

As a preliminary matter, simply making all standards less stringent than they otherwise may be will not address concerns about achievability and enforceability associated with emissions variability, as EPA appears to believe is the case. *See id*. at 44,766. Similarly, longer compliance schedules also may not fully address variability, *see id*., and neither will the use of non-BSER measures, *see id*. at 44,765.[26] At a minimum, it would be helpful if EPA would describe a process for how states can set performance standards in a manner that provides sufficient flexibility to assure both achievability and enforceability, since this is critical to the success of the program.

EPA proposes to require that all state plans include measures that provide for the implementation and enforcement of the emissions standards to be applied to all affected units. *See id*. Further, EPA has not addressed the requirements of CAA section 302(k):

> The terms "emissions limitation" and "emission standard" mean a requirement established the State or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of source to assure continuous emission reduction….

[26] For some units and for some states, these tools may be useful and may address emissions variability. But, they will not address all variability concerns, which is why EPA should not foreclose states from considering a range of compliance flexibilities.

42 U.S.C § 7602(k). Courts have interpreted this requirement to mean that standards should apply at all times and that efforts to exempt periods of operation are contrary to the plain language and intent of the Act. *See Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008), *cert. denied*, 130 S. Ct. 1735 (2010). As currently contemplated in the proposed ACE rule, states would develop a single emissions rate standard for each affected unit. As explained above—and given the documented variability in emission rates related to a host of factors—it is not clear how states could develop a single rate that would be deemed both achievable and enforceable.[27]

C. EPA Should Permit States to Develop State Plans that Include Compliance Flexibilities that Address the Operational and Technical Concerns Identified in These Comments, Consistent with the Requirements of the CAA; EPA Should Provide Guidance on Compliance Flexibility but Should Be Clear that States Can Explore All Options.

States need flexibility when creating and setting standards. While determining BSER at the source, or "inside-the-fence" is consistent with the source-based nature of section 111 of the CAA, the ACE rule should allow states flexibility to set compliance standards while using a range of mechanisms both to reduce the cost of compliance and ensure that the standards are achievable. EPA has not considered emissions rate variability sufficiently in the determination of BSER and has compounded the problem by mandating a limited approach to compliance that focuses exclusively on measures that can be accomplished at the unit. While some of the more limited compliance flexibilities EPA proposes to permit, like averaging, would help address

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[27] Different kinds of standards can apply during different periods, to reflect operational issues or optimal functioning of control technologies. For example, while continuous compliance is required with an emission limits under the Mercury and Air Toxics Standards, the Agency provided for work practice standards for periods of startup and shutdown. *See Reconsideration of Certain Startup/ Shutdown Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial- Institutional, and Small Industrial- Commercial-Institutional Steam Generating Units,* 79 *Fed. Reg*. 68,777 (Nov. 19, 2014).

variability in some instances, greater flexibility may be needed to ensure that standards are implementable and enforceable. EPA should not be prescriptive in any final ACE rule as to how compliance is achieved and what types of compliance flexibilities are or are not permissible. EPA should instead allow states to include such flexibilities as they deem appropriate for units under their jurisdiction. This would be consistent with EPA's recognition that states have significant flexibility in determining emissions standards for units, as contemplated by the CAA. *See id*. at 44,763. The form of the standard and the methods for demonstrating compliance are part of the standard, and states should be afforded the same flexibility when determining these elements as well. *See id*. at 44,765 (noting that "states also have flexibility in the measures and processes that they put in place for affected EGUs to meet their compliance obligations").

EPA can assess the reasonableness of a state's proposed flexibilities in the context of each state plan, which the Agency is obligated to review. It would be appropriate for EPA to provide states some guidance on how to implement certain forms of compliance flexibility, as well as guidance on appropriate mechanisms to evaluate emissions variability in setting a performance standard.

1. Averaging Could Help States and Units Address Emissions Variability.

EPA proposes to allow limited averaging as a potential compliance flexibility for states and affected units. *See* 83 *Fed. Reg*. at 44,769, 44,765 and 44,767. Specifically, EPA proposes to afford states discretion in establishing averaging times for compliance demonstrations for individual affected EGUs. EPA also proposes to allow limited averaging across affected units within the same facility for compliance purposes. Both forms of averaging may be useful in certain instances to address emissions variability and should be options that states could choose to include in their compliance plans.

For some affected EGUs, longer compliance averaging provisions may smooth out variability in hourly emissions. This tool has been permitted by EPA in the context of GHG emission standards for new units under CAA section 111(b). *See, e.g.*, 60 C.F.R. § 60.5540 (allowing for 12-month rolling averages for compliance demonstrations). Given the annual and multi-year variability in emissions for some units, longer averaging periods also would be appropriate tools for states to consider.[28]

Similarly, averaging across units at the same facility, as EPA proposes, may help address emissions variability, facilitating enforceable emissions standards for a group of units, and allowing implementation of efficiency measures that are most cost-effective and result in the most meaningful improvements at specific units, rather than compelling minor improvements at all units. *See* 83 *Fed. Reg.* at 44,767. EPA's proposal to limit such averaging only to those units at the same facility, however, is not required by law. Averaging across a larger number of units—for example, those within a state—could help address overall emissions variability, while still ensuring that emissions rates are achieved. Such an approach is similar to that used under CAA section 110 compliance programs, which allow emissions trading—another form of averaging.

[28] Similar to the approach taken to standards based on the Best Available Control Technology (BACT) analysis under CAA section 169, the standards established by states under section 111(d) should not be set to reflect the maximum possible emissions control under the most favorable conditions, but instead at levels that will allow units to achieve compliance consistently. BACT standards often reflect a compliance margin and are coupled with appropriate averaging periods. *See In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 188 (EAB 2000); *see also In re Knauf Fiber Glass, GmbH*, 9 E.A.D. 1, 15 (EAB 2000).

Further, should they choose to do so, states should be able to utilize averaging across affected and unaffected units as an option for compliance purposes. Such averaging also could provide significant compliance benefits, allowing states not only to develop enforceable standards, but also to recognize significant investments in lesser-emitting generation. Allowing this type of averaging for compliance may obviate the need for states to use the variance provision to address the remaining useful life of an affected unit, making the establishment of emissions standards significantly easier for states. *See id.*

Accordingly, EPA should permit states to propose a range of averaging options in their compliance plans, as this may assist states in establishing enforceable standards for affected units with variable emissions rates.

2. Measuring Standards in Terms of Mass Emissions Could Provide Significant Operational Flexibility to Affected EGUs.

EPA proposes to limit the form of the standard to an emission rate of pounds of CO_2 per Megawatt-hour (MWh). *See* 83 *Fed. Reg.* at 44,764. Converting an emissions rate standard into a mass cap provides significant operational flexibility to units because mass caps do not require hourly compliance and therefore address intraday and monthly emissions variability concerns. Such flexibility has been incorporated into the GHG prevention of significant deterioration (PSD) permits issued by many states to new and modified units.[29] States should be permitted to convert emissions rate standards into emissions mass caps if this would help address variability and other compliance challenges.

[29] *See* analysis of GHG PSD permits, Appendix B.

3. EPA Should Permit States to Propose Trading Programs in Order to Develop Achievable and Enforceable Emissions Limits for Affected Units.

EPA solicits comment on trading but identifies legal and practical concerns with allowing states to incorporate trading into their compliance plans. *See id.* at 44,767-68. Specifically, EPA notes that permitting trading may allow states to implement standards that are more stringent than those that would be applicable otherwise and that it would be too difficult to address the required evaluation, monitoring and verification (EM&V). *See id.* These concerns should not be impediments to trading, should a state propose to include this as a compliance option.

Trading would be provided as a compliance option *after* setting the standard. It would not be used to determine the standard. Trading harnesses market incentives and typically reduces compliance costs. Trading was employed by Congress in the 1990 CAA Amendments as part of the Acid Rain program to reduce emissions of SO_2. No affected unit was required to engage in trading, but trading was an option that many, if not most sources, chose to participate in, as either a buyer or seller. But Congress had predetermined the reductions required. In much the same way, EPA needs to differentiate the basis for standard setting from the options for compliance. Trading here would be a compliance option, not a standard setting tool.

As noted above, emissions trading is on some level another form of emissions averaging. Both would help address emissions variability. While EM&V is an important issue in any trading program, both EPA and the states have significant experience in this area upon which to draw. For example, the EPA has established successful trading programs in rules including the NOx state implementation plan (SIP) Call and the Cross-State Air Pollution Rule (CSAPR), among others.[30] In those programs, trading was based on an evaluation of the level of reductions achievable at individual sources and the requirements were translated into emissions budgets, which were determined to be equivalent or more stringent than the achievable level of emissions at the sources.

4. Other Forms of Compliance Flexibility Could Help Address Emissions Variability; EPA Should Permit States to Propose Different Approaches in Compliance Plans and Should Not Preemptively Determine That Any Potential Flexibilities Are Invalid.

While these comments identify some of the compliance options that states could include in their compliance plans to address emissions variability and other state and local factors, this discussion is not meant to be exhaustive. States should be able to propose any compliance flexibilities that would allow for the development of enforceable emissions standards for affected units. EPA should not preemptively determine that any particular compliance flexibility option is invalid. Instead, EPA should assess each state plan on its merits. As noted, EPA could help the states develop achievable, enforceable emissions rate standards of performance by providing guidance as to the implementation of certain compliance options.

IV. EPA Should Clarify The Applicability Of The Proposed ACE Rule.

As discussed, EPA proposes that BSER is a menu of HRI that could be undertaken at the affected unit. The Agency defines an affected EGU, *i.e.*, a unit that is subject to regulation, as any fossil fuel-fired EGU that was in operation or under construction as of August 31, 2018. Affected EGUs also must be fossil fuel-fired electric utility *steam* generating units that are

[30] *See, e.g.,* EPA's NOx Budget Trading Program, 63 *Fed. Reg.* 57356 (Oct. 27, 1998); the Clean Air Interstate Rule, 70 *Fed. Reg.* 25,161 (May 12, 2005); CSAPR, 76 *Fed. Reg.* 48,208 (Aug. 8, 2011); and the CSAPR Update Rule, 81 *Fed. Reg.* 74,504 (Oct. 26, 2016).

capable of selling more than 25 MW to the grid and with a base load rating greater than 260 G/h (250 MMBtu/h) heat input of fossil fuel. *See* 83 *Fed. Reg*. at 44,754. As noted in the proposal, these applicability requirements differ from those used in the CPP and reflect the fact EPA only proposes a BSER for steam EGUs. *See id*. However, like the CPP, EPA proposes that units that are not deemed affected would be exempt from inclusion in state compliance plans. *See id*. at 44,755.[31] In particular, the Agency did not identify a BSER for integrated gasification combined cycle (IGCC) units or stationary combustion turbines, so these units are not considered to be affected units and are exempt from inclusion in state compliance plans. *See id*. at 44,754.

Despite the discussion of applicability in the proposed ACE rule, EGU owners and operators are unclear as to which units may be subject to the proposed ACE rule and would need to be included in state compliance plans. EPA should clarify the applicability of the proposed ACE rule, as discussed below.

A. EPA Must Clarify the Proposal with Respect to NGCCs, Which Have a Steam Component, and Other Natural Gas-Based Steam Boiler EGUs.

As noted, the proposed rule states that an affected unit is any fossil fuel-fired electric utility steam generating unit that meets certain size and capability requirements. *See id*. The proposal is

[31] EPA lists six types of EGUs that would be exempt from inclusion in state plans: 1) units subject to 40 C.F.R. § 60 subpart TTTT as a result of modification or reconstruction; 2) steam generating units subject to federally enforceable permit limits that limit net electric sales to one-third or less of their potential electric output or 219,000 MWh on an annual basis; 3) non-fossil units that limit the use of fossil fuels to 10 percent or less of the annual capacity factor or are subject to a federally enforceable permit limit to this effect; 4) units that serve a generator along with other steam generating units where the effective generation capacity is 25 MW or less; 5) municipal solid waste incineration units subject to 40 C.F.R. § 60 subpart Eb; or 6) commercial or industrial solid waste incineration units subject to 40 C.F.R. § 60 subpart CCCC. *See* 83 *Fed. Reg*. at 44,755. Should EPA determine that any of these types of units should be included in state plans to comply with the proposed ACE rule, EPA would have to provide an opportunity for notice and comment on the appropriate BSER for these types of units.

clear that this does not include IGCC units and stationary combustion turbines. *See id*. Consistent with this, in any final rule, the Agency must clarify whether natural gas combined cycle (NGCC) units, which have a steam generating component, are affected units. Additionally, the Agency should clarify whether natural gas-fired steam boilers are affected units and whether they are subject to inclusion in state plans.

Further, the Agency should not set a BSER for NGCCs in this docket given the lack of information currently in the record. EPA, in fact, notes that "no commenters provided specific information on the availability, applicability, or cost of HRI opportunities for NGCC units—nor did any commenters provide any information on the magnitude of expected heat rate reductions." 83 *Fed. Reg*. at 44,761. However, if the Agency does receive such information, it would be necessary and appropriate for EPA to initiate a separate rulemaking (or, at minimum, a supplement to this rulemaking) to provide all stakeholders sufficient notice and opportunity to comment on such data and any BSER that EPA may propose as a result.

EPA cannot reconsider the determination that there are no HRIs that represent BSER for NGCCs and cannot develop BSER for other natural-gas steam boiler EGUs without such notice and comment. While EPA has generally explored whether HRIs are available for NGCCs, *see id*.,[32] EPA's analysis fails to identify and address fundamental issues related to potential HRIs at

[32] EPA's attempt to assess a benchmark heat rate for NGCCs by looking at historic national performance is fundamentally flawed if the goal is to determine BSER. *See* 83 *Fed. Reg*. at 44,761. While certain classes of turbines have design specifications that include expected heat rate, actually achieved heat rates depend on an array of unit-specific factors. A national average obscures these factors and, therefore, could never serve as BSER as it would not lead to an achievable standards, consistent with the requirements of CAA section 111(a).

NGCCs. Specifically, the Agency does not address that efforts to obtain HRI at NGCCs likely will involve upgrading significant components, including the compressor, combustor or entire turbine gas path.[33] Implementing these upgrades may cross the line from HRI project to modification or reconstruction, which could require that these units be regulated under CAA section 111(b) instead of section 111(d). See 40 C.F.R.§ § 60.14 and 60.15. Further, an approach to HRI projects at NGCCs that required such major upgrades would be inconsistent with EPA's proposed BSER, which rejects standards that can only be accomplished through a fundamental redesign of the source. *See id.* at 44,753. (Comment C-3).

B. EPA Should Clarify the Cut Off Date Between New and Existing Fossil Steam Generating Units for Purposes of Regulation under CAA Section 111(d).

In the proposed ACE rule, EPA states that an affected EGU is any fossil fuel-fired electric utility steam generating unit that was in operation or had commenced construction as of August 31, 2018. *See* 83 *Fed. Reg.* at 44,754. However, in a footnote, EPA recognizes that "under section 111(a) of the CAA, determination of affected sources is based on the date that EPA proposes action on such sources" and that "January 8, 2014, is the date the proposed GHG standards for performance for new fossil fuel-fired EGUs were published in the Federal Register." *Id.* The proposed rule's approach to applicability appears to be contrary to the requirements of the CAA with respect to establishing a cutoff date between existing and new units. EPA needs to both clarify what the applicability date is and offer a full explanation for its rationale if that date has changed from the January 8, 2014 date.

[33] See J. Edward Cichanowicz, *Availability and Status of Heat Rate Improvement (HRI) Actions Applicable to Gas Turbines in the Context of the Affordable Clean Energy Rule* (Oct. 2018), submitted as part of the comments of the Utility Air Regulatory Group in Docket No. EPA-HQ-OAR-2017-0355.

No new coal-based steam EGUs have come online since January 8, 2014, which means that the change in applicability date has no practical effect. That is, there are no coal-based units that were considered to be new sources, subject to regulation under CAA section 111(b), that would now instead be considered existing sources, subject to inclusion in a state's section 111(d) compliance plan. However, if coal-based units had been built or started operation during this period, this change in applicability date would have resulted in a significant and unexpected change in applicable performance standards. While not presenting such concerns, this change in applicability date creates uncertainty for other units. For example, if EPA were to find that there are HRI projects that could be determined to be BSER for other units, including NGCCs, this change in applicability date would change the applicable standards for the many NGCCs that were built or started operation since early 2014 and have incorporated the relevant section 111(b) standards into their operating permits. Accordingly, to avoid creating regulatory uncertainty, EPA should clarify what the applicability date is and offer an explanation if it has changed.

V. The Proposed Revisions to The Section 111(d) Implementing Regulations Are Reasonable And Appropriate But Require Clarification and Revision Before Finalization.

EPA proposes to update and amend the CAA section 111(d) implementing regulations to address several issues. Among other things, these include: changes and updates to definitions; updated timing requirements; new completeness criteria and processes for determining completeness; updated public hearing requirements; and an updated variance provision. *See* 83 *Fed. Reg.* at 44,770. As a general matter, these proposed changes and revisions are appropriate. However, EPA should provide some clarifications related to these proposed changes and amendments, as described in more detail below.

While EPA considers the proposed revisions to the implementing regulations to be a separate and distinct proposal from the ACE rule, *see id*. at 44,783, it is not clear how states and the owners and operators of affected units could begin to devise approvable state plans for submission to EPA without such regulations in place. Accordingly, EPA should finalize these proposed revisions—reflecting the clarifications and revisions discussed below—along with any final ACE rule.

A. Updating the Timing Requirements Related to State Plan Submittals Is Appropriate.

EPA proposes to update the timing requirements in the CAA section 111(d) implementing regulations. These proposed changes would address the timing for the development, submission and review of state plans, as well as EPA's promulgation of federal plans if required. *See* 83 *Fed. Reg.* at 44,771. EPA, in part, is updating the timing requirements to be consistent with those in the CAA section 110 implementing regulations, which govern the development, submission and review of SIPs. Generally, these changes are appropriate given the amount of work states will be required to develop state plans that include unit-specific performance standards based on an assessment of the menu of HRI projects that EPA has determined to be BSER. Further, given the expressly acknowledged relationship between CAA section 110 state implementation plans and state compliance plans under section 111(d),[34] conforming to the timing requirements of section 110 is reasonable. The CAA does not specify any particular compliance timeline for CAA

[34] Section 111(d) states that "the Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source…" 42 U.S.C. § 7411(d)(1).

section 111(d) regulations, so providing sufficient time to develop and review complicated state plans is consistent with the Act.

Specifically, EPA is proposing to allow states up to three years, rather than nine months, to adopt and submit their state plan to EPA after promulgation of a final 111(d) emission guideline. *See id*. EPA proposes this change recognizing that there is a tremendous amount of work for a state to develop state plans, especially ones with unit-specific standards. States will need adequate time to work with EGU owners and operators to determine the unit specific standards that will be included in state plans and be enforced against EGUs. Moreover, at least with respect to standards of performance for GHG emissions from existing affected EGUs, additional time for states to develop and submit a state plan is necessary as the proposed rule provides little guidance as to how states should set these standards but requires that significant information about each affected unit be contained in the state plan. *See, e.g.,* proposed 40 C.F.R §§ 60.5735a and 60.5740a. It will take time for states to develop these plans and nine months will not be sufficient. As discussed below, EPA should provide states additional guidance on establishing a unit-specific standard of performance to help states develop approvable state plans.

Likewise, EPA is proposing to allow EPA up to 12 months, rather than four months, after a state submits its state plan to determine whether the plan is complete. *See* 83 *Fed. Reg*. at 44,772. In addition to changing the deadline for EPA to determine the completeness of a state plan, EPA also proposes completeness criteria against which EPA would compare a state's submission to determine completeness. *See id.* at 44,772. The proposed completeness criteria are similar to the completeness criteria under CAA section 110 and therefore reasonable.

Finally, EPA is proposing to allow EPA up to two years, rather than six months, from the date EPA disapproves a state plan—either as a result of determining that a state plan is incomplete or because a state failed to submit a plan—to issue a federal plan. *See id.* at 44,771. This proposed change also is reasonable, as EPA, like the states, will have to conduct a unit-by-unit analysis to establish performance standards for each affected unit that would be addressed in the federal plan. Just as developing a state plan is a time-intensive process, so too is developing a federal plan, therefore allowing EPA up to two years—as is consistent with the timing requirement under CAA section 110—is appropriate. It is expected that states will work closely with affected units when developing compliance plans; EPA should similarly engage the regulated sources should the development of a federal plan be necessary.

B. The Proposed Updates to the Plan Completeness Criteria and Process for Determining Completeness are Appropriate, But Some Required Elements of State Plans Would Require Speculation and the Potential Provision of Confidential Business Information that Could Impact Electricity Markets; EPA Should Revise These Requirements.

EPA proposes to amend the completeness requirements for state plans under CAA section 111(d). *See id.* at 44,772. In general, these amendments would make the section 111(d) completeness requirements more consistent with those for SIPs under CAA section 110, with criteria addressing both administrative materials and technical support. *See id.* The revisions also address how EPA would determine whether a state plan is complete and provide a timeframe for an Agency completeness determination. *See id.* EPA states that these criteria will apply to all CAA section 111(d) plans submitted after these revised regulations are finalized. *See id.*

In general, the proposed revisions to the regulations addressing completeness are appropriate. Given the statutory mandate that EPA establish a procedure for section 111(d) state plans that is similar to the one provided in CAA section 110 for SIPs, *see* 42 U.S.C. § 7411(d), EPA's determination that the completeness criteria for 111(d) plans mirror those for SIPs makes sense.

However, beyond the general technical support requirements that must be included in order for a state plan to be deemed complete, EPA has proposed a number of additional requirements for state plans that would regulate GHGs from existing fossil fuel-fired electric steam generating units and seeks comment on whether this list is comprehensive (Comment C-46). EPA's concern about comprehensiveness is misplaced. Many of these proposed plan elements are not only overly burdensome for both states and affected units but also require information that cannot be known at the time that the state plans are submitted to EPA and, if known, may constitute confidential business information (CBI) that could have impacts on electricity markets if made public.

For example, EPA proposes to require the following data in state plans:

(4) Your plan demonstration, if applicable, must include the information listed in paragraphs (a)(4)(i) through (v) of this section as applicable.

(i) A summary of each affected EGU's anticipated future operation characteristics, including:

(A) Annual generation;

(B) CO_2 emissions;

(C) Fuel use, fuel prices (when applicable), fuel carbon content;

(D) Fixed and variable operations and maintenance costs (when applicable);

(E) Heat rates; and

(F) Electric generation capacity and capacity factors.

(ii) A timeline for implementation of EGU-specific actions (if applicable).

(iii) All wholesale electricity prices.

(iv) A time period of analysis, which must extend through at least 2035.

(v) A demonstration that each standard of performance included in your plan meets the requirements of § 60.5755a.

Proposed 40 C.F.R. § 60.5740a(a)(4), 83 *Fed. Reg.* at 44,809.

The required inclusion of this information would require states and EGU owners and operators to provide information that, by and large, simply would not be knowable at the time that the state plans were due. For example, it is not possible to know annual generation, related CO_2 emissions, fuel use, fuel prices, O&M, heat rates, capacity factors and all wholesale electricity prices from the time of plan submission through 2035. As discussed in detail above, individual unit's operations are functions of many variables, including electricity demand and the composition of the fleet of EGUs that are available to provide electricity in any given period.

While it may be possible to make predictions about some of these required plan elements, such projections are costly, time consuming and rarely accurate with a degree of certainty required for environmental regulatory planning, particularly at the individual unit level. Electric companies can and do estimate future demand, and they use this information to plan for additional generation sources in the long-term and fuel purchases in the shorter-term. But taking these system projections down to the unit level is problematic. An unexpected forced outage at one unit affects generation at other units. If a nuclear unit cannot run, multiple coal units might be operated, even though their expected operations were low prior to the nuclear outage. This sort of event, with its ripple effects, occurs numerous times over any given year, and the larger the fleet, the more unpredictable the outcome. But of note, none of these changes in generation affect customer demand. So, while electric utilities might accurately enough predict demand and even generation at the system level, predicting individual unit operations years into the future is inherently uncertain.

However, the proposed regulations do not ask for predictions, they ask for a summary of future operating characteristics, failing to recognize that most of this information will not be knowable at the time that plans are submitted for EPA review. Further, EPA has not provided a reasoned basis for seeking such information and how such information would be useful to EPA in evaluating state plans or the standards of performance for existing EGUs that may be included in state plans. EPA should avoid embarking on any data fishing expeditions.

Potentially more problematic, if some of this information is known at the time of plan submittal, it could constitute CBI, particularly with respect to EGUs that compete to sell power in wholesale electricity markets. Much of the price and expected output information that EPA seeks would be similar to information required to be included in bids to provide energy and other services to wholesale markets. Providing this information in publicly available state plans could have detrimental effects on competition and customers, particularly as it would result in a one-sided dissemination of cost and other sensitive information about units as only coal-based units would be required to make such data public.[35] And it is not sufficient to expect that utilities could protect this information by designating it as CBI. While protection under the Freedom of Information Act (FOIA)[36] may protect its disclosure, not all states provide the same level of protection to sensitive information. For example, North Carolina's robust public records laws protect only "trade secrets," which is defined more narrowly than CBI under FOIA.

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[35] As noted above, EEI is seeking clarification on exactly what types of units would be covered under the proposed rule.

[36] *See* 5 U.S.C. § 5562

Accordingly, given that EPA has requested detailed information that likely cannot be known at the time state plans are submitted for review (and is certainly unknown for the long timeframes in which EPA seeks data) and that this information, if it could be provided, could negatively affect electricity competition and customers, EPA should withdraw these requirements. EPA has not provided a reasoned basis for requiring that this information be included in state plans or how it would be evaluated, and the burdens and harms from providing this information would far outweigh any benefit related to the ACE rule that EPA could articulate.

C. EPA's Proposed Monitoring Requirements Are Generally Appropriate, But EPA Should Provide States and Units More Flexibility in Recognition of Changing Operations.

EPA proposes that state plans include appropriate monitoring, reporting and recordkeeping requirements to ensure that the plans adequately provide for the implementation and enforcement of the standards of performance for affected units. *See* 83 *Fed. Reg*. at 44,768. To this end, EPA notes that most potentially affected coal-based EGUs already continuously monitor emissions, as well as heat input, and gross electric output, and report this hourly data to EPA under 40 C.F.R. part 75. *See id*. at 44,769. Accordingly, EPA proposes to allow states to use the data collected under part 75 to meet the monitoring, reporting and recordkeeping requirements. *See id*.

As a general matter, it is appropriate to allow states to use part 75 data to satisfy the monitoring, reporting and recordkeeping requirements for CAA section 111(d) compliance plans. Using already collected data to serve multiple purposes is efficient. However, EPA must recognize that part 75 was designed to address the needs of emission trading programs, not performance standards expressed as unit-specific emission rates. To the extent that states use an emission rate approach in their plans, adjustments to the monitoring and reporting requirements to eliminate periods of substituted data, minor downtime, calibration periods and other invalid data must be allowed.

EPA also should make clear in any final ACE rule that states can use alternative methods to address monitoring, reporting and recordkeeping requirements. For example, states should be permitted to consult with affected EGU owners and operators to determine the most appropriate emissions testing and heat rate measurement methods. States should be permitted to allow units to use alternative methodologies to measure stack air flow as appropriate.

States also should be permitted to allow units to determine heat rate by means other than through reference to continuous emission monitoring system (CEMS) data. There can be significant variation between the heat rate determined using CEMS data and other methods because of as-burned fuel conditions that can affect the heat input of fuel at individual EGUs that may not be reflected in CEMS data, delinking the data from the actual thermal performance of the boiler. For this reason, some owners and operators use a heat balance approach. EPA's final ACE rule should provide states flexibility on how to address monitoring, reporting and recordkeeping so long as they appropriately document and explain the need for any alternative approaches.

D. EPA Should Provide Additional Guidance About the Use of the Proposed Variance Regulations Generally and How to Utilize the Variance Provisions to Address Remaining Useful Life and Other Factors When Establishing a Unit's Standard of Performance Specifically.

Throughout the proposal, EPA identifies a variety of factors that states can consider when establishing standards of performance for affected units. *See, e.g.*, 83 *Fed. Reg*. at 44,766 and 44,773. Specifically, EPA identifies factors laid out in CAA section 111(d)(1)(B), including the remaining useful life of the unit. *See id*. at 44,766. Consistent with the statutory recognition that setting standards for existing units may require consideration of a range of mitigating factors, EPA proposes revisions to the variance provision in the CAA section 111(d) implementation regulations that would allow states to apply less stringent standards to sources under certain circumstances, regardless of whether standards are health- or welfare-based. *See id.* at 44,773. Revising the existing variance provision in this manner is appropriate and consistent with the direction in CAA section 111(d)(1)(B) that states be allowed to consider remaining useful life and other factors when setting performance standards for existing units.

EPA is clear in the proposed ACE rule that its authority extends to the determination of BSER and that CAA section 111(d)(1) assigns authority to the states for establishing standards of performance for affected existing EGUs. *See id*. at 44,755. Nevertheless, it is appropriate for EPA to guide states on how they might choose to establish standards of performance that EPA will find approvable. Given the unit-specific nature of the proposed BSER, states likely will rely on the proposed variance provision to develop such standards. EPA does not provide guidance to the states as to how to use this variance provision to address the factors enumerated in the statute or any other factors that the state may appropriately consider when setting performance standards and instead seeks comment on how states can use the variance provision to set performance standards for affected units (Comment C-58). In any final rule, EPA should provide such guidance; or, at the time of finalization, EPA should issue guidance to the states that addresses how to use the variance procedure in the regulations. Given that EPA recognizes that a host of unit-specific factors and other unique unit attributes may be relevant when states set performance standards for affected units, there is no need for EPA to enumerate all potential factors that states could consider (Comment C-23; Comment C-57). Rather, EPA should provide examples of how to consider such factors in setting standards so that states have some guidance as they craft compliance plans but should not be prescriptive about the factors that states could consider. EPA and stakeholders can assess the appropriateness of such considerations when reviewing state plans.

This proposed rule strongly suggests that EPA intends for remaining useful life considerations, which are identified in CAA section 111(d) as a factor in setting standards, to be addressed only through the variance process. *See id*. at 44,766. However, EPA does not provide states any examples on how and to what extent remaining useful life is factored into establishing a standard of performance or how to use the variance provision to factor remaining useful life into the development of a performance standard. To help states develop approvable compliance plans, EPA should provide more specificity regarding how states and sources could consider the remaining useful life of a unit through the variance provision and, accordingly, how to set emissions standards consistent with this analysis. Such guidance could include numeric examples, using hypothetical units, emissions rates and remaining useful life.

VI. EPA's Proposed New Source Review Reforms May Address Potential Deterrents to Undertake HRI Projects to Comply With Section 111(d), But Could Be Severed From This Proposal.

As EPA notes, an affected EGU that undertakes an HRI project for purposes of compliance with a state's CAA section 111(d) compliance plan could trigger NSR permitting requirements under the current applicability test. *See* 83 *Fed. Reg*. at 44,777. NSR permitting can add significant time and expense to such projects and could complicate the development and implementation of state compliance plans, especially if the only option for compliance is to undertake HRI projects at the affected EGU. To address this, EPA is proposing to amend the NSR regulations to include a new hourly emission increase test for EGUs for determining NSR applicability, with the goal of minimizing the potential to trigger NSR permitting requirements. *See id.* If a final ACE rule provides limited compliance flexibility, as discussed above, reform of the NSR applicability test could further ease compliance, as triggering NSR could deter EGU owners and operators from undertaking necessary HRI projects, with owners instead choosing to close units rather than make investments in units that may not be recoverable.

A. Reform of New Source Review Permitting Requirements Could Address Potential Deterrents to Engaging in HRI Projects at Affected Units.

As a preliminary matter, it is important to note that any increase in the amount of any air pollutant that could be imputed to an HRI project depends on many factors that either cannot be known at the time of permitting or could change over the course of a unit's operations. Despite this, assertions that all HRI projects automatically will cause increased dispatch of any particular unit and result in increased emissions of air pollutants are based on a fundamental misunderstanding of how the power sector operates and are easily disproven. For example, if all units in a given utility's system were to undertake an HRI in the same year, it is not reasonable to assume that each would operate more than previously, because the system operates to meet customer demand, which is not affected by the HRI projects. Moreover, as the HRI projects are more likely staggered over several years, even if a unit operated more the year following its HRI, in subsequent years its improved efficiency would deteriorate, while other units undertaking HRI project would have improved performance.

Because electricity must be supplied in real time to meet demand, EGUs cannot unilaterally decide to increase production; there first must be an increase in demand or a reduction in other required generation, such as a baseload unit outage. While an HRI project may decrease an EGU's total fuel costs, these projects involve capital expenditures that could increase a unit's marginal cost. As a result, an HRI project does not necessarily make a unit more competitive per se and cannot be said to result automatically in increased dispatch and increased emissions.

In some cases, EGUs may forgo efficiency improvements to avoid triggering NSR permitting requirements. NSR pre-construction permitting requirements can require costly, detailed analyses and result in permitting delays; in some cases, they also result in costly and protracted litigation, as well as expensive new emission control requirements that also create additional time delays for projects. Indeed, many unit owners and operators undertake HRI projects and other efficiency improvement efforts when addressing other unit upgrades that already have triggered NSR permitting so as to avoid a second round of permitting review just for these projects. Accordingly, addressing NSR applicability could facilitate compliance with CAA section 111(d) state plans.

If EPA chooses to finalize the proposed revisions to the NSR applicability test and related regulations, EPA should not limit the new approach only to those units that are undertaking HRI projects for purposes of CAA section 111(d) compliance or otherwise limit the new approach based on geography or pollutant (Comment C-62). Such limits would discourage HRI projects. For example, a limit on the new approach that tied it exclusively to CAA section 111(d) compliance is potentially problematic as it is not clear at this time how states will design compliance plans or choose to measure compliance. As discussed above, HRI projects degrade over time. It is not clear whether future investments to address this degradation would be considered to be for the purposes of CAA section 111(d) compliance, potentially subjecting EGUs to different tests for applicability over the life of the same HRI project. With respect to potential geographical limits, the record provides no grounds on which to reasonably differentiate between units in different parts of the country, particularly as ACE would apply to all affected units, regardless of location. Finally—with respect to pollutants—any effort to encourage HRI projects to comply with CAA section 111(d) or help states develop compliance plans would be undermined if all regulated NSR pollutants were not covered by the proposed new approach to determining NSR applicability.

B. Additional Compliance Flexibility Might Obviate NSR Concerns Related to Section 111(d) and Is Consistent with EPA's Goals in Proposing NSR Reform.

The proposed ACE rule, as currently drafted, requires states to establish unit specific standards and provides minimal compliance flexibility to meet those standards. *See id.* at 44,748. This means that EGU owners and operators would either have to comply with the performance standard and risk triggering NSR permitting requirements and the additional attendant costs and delays by undertaking HRI projects; face potential non-compliance; or engage in unit closure. While EPA's proposal does grapple with some of these challenges through the proposed NSR revisions, these challenges would remain if the revised applicability test is not finalized or does not survive legal challenge. As discussed above, EPA should authorize states to consider additional compliance flexibilities in order to achieve environmental performance in the most cost-effective manner. Additional flexibilities could potentially reduce the number of EGU owners who may trigger NSR permitting requirements in connection with compliance with the proposed ACE rule because there would be options, other than unit-specific HRI projects, for compliance. Further, authorizing states to consider a range of compliance flexibility in state plans, beyond those that could be undertaken strictly at the source, is consistent with EPA's stated goals for amending the NSR applicability test: providing states with options for efficient and effective compliance. *See id.* at 44,776-777.

C. EPA Could Sever the Proposed NSR Revision and Finalize It Separately from the ACE Proposal.

As discussed, the NSR permitting program and the proposed ACE rule are related to one another in that compliance with ACE could trigger NSR; however, they are ultimately separate and distinct programs. As EPA notes, the Agency views the proposed ACE rule as "appropriate policies in their own right and on their own terms" and intends the proposed NSR revisions to be severable upon judicial review. *See* 83 *Fed. Reg*. at 44,783. Accordingly, EPA could finalize the proposed NSR changes separately from the finalization of the ACE rule (Comment C-71).

A separate approach may make sense, particularly if the proposed changes to the NSR program would not be limited to units engaging in HRI to comply with an 111(d) standard and would instead be more broadly applicable. This would allow legal challenges to one proposal to proceed without necessarily delaying the other. Given that the section 111(d) state plans likely would not be due to EPA for review until 2022 at the earliest, there is sufficient time to move the two proposals separately, while still ensuring that the intended goals of the amendments to the NSR program—addressing the concerns about the potential effects of these permitting requirements on HRI projects—is accomplished in a timely fashion.