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1200 Pennsylvania Avenue, NW
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February 23, 2018

By E-mail to Regulations.gov

Re: State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units - Advance Notice of Proposed Rulemaking
Docket No. EPA–HQ–OAR–2017–0545

Ladies and gentlemen:

These comments are submitted on behalf of the labor union members of Unions for Jobs and Environmental Progress (UJEP), identified below.

We welcome EPA's invitation to comment on the design of a potential replacement to the Clean Power Plan. 82 Fed. Reg. 61,507, December 28, 2017. UJEP member unions represent workers from the electric utility, mining, rail, and construction sectors. We have participated for many years in various EPA rulemaking proceedings, including those related to ozone standards and ozone transport, new source performance standards, the MATS rule, and the Clean Power Plan.

UJEP is an ad hoc association of labor unions involved in energy production and use, transportation, engineering, and construction. Our members are: International Association of Bridge, Structural, Ornamental and Reinforcing Iron Workers Union; International Brotherhood of Boilermakers, Iron Ship Builders, Blacksmiths, Forgers and Helpers; International Brotherhood of Electrical Workers; International Brotherhood of Teamsters; SMART Transportation Division; Transportation • Communications International Union - IAM; United Association of Journeymen and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada, and United Mine Workers of America. For more information about us, visit www.ujep4jobs.org.

Our comments set forth a number of principles for EPA to consider as it moves forward with the development of a replacement to the Clean Power Plan. As stated in our January 8th comments[1] in support of the proposed repeal of the CPP, we believe that the rule was fatally flawed as a result of its "outside-the-fence" focus on emissions reductions through redispatching and investments in new renewable energy projects, as well as its failure to provide states with the flexibilities provided by section 111 of the Clean Air Act and its implementing regulations.

Replacing the Clean Power Plan

EPA should replace the Clean Power Plan (CPP) with an alternative regulatory approach for reducing CO_2 emissions from existing coal- and gas-fired electric generating units (EGUs). UJEP members support a new regulatory framework for the replacement rule based on "inside the fence" power plant equipment and efficiency improvement measures undertaken at each EGU.

The new framework should adhere to statutory requirements for regulating existing sources under section 111(d) of the Clean Air Act (CAA). These requirements give states the primary role in regulating CO_2 emissions from existing EGUs through the establishment of CO_2 performance standards. In addition, as discussed below, EPA should proceed through a separate rulemaking to reform current NSR regulations to maximize the ability of electric utilities to perform efficiency improvement projects under a CPP replacement rule.

The "inside the fence approach" advocated in our comments is consistent with the positions taken by Administrator Pruitt in his previous capacity as Oklahoma Attorney General ("OKAG"):

> The OKAG Plan properly construes Section 111(d): EPA designs a procedure and emission guidelines, and States determine the legally enforceable emission standard that is as stringent as the applicable guideline – *unless* the State determines that circumstances justify imposition of a less stringent emission standard. The OKAG Plan institutes a unit-by-unit, "inside the fence" approach to determining State emission standards, and accounts for the practical reality that air quality impacts differ from State to State, as do costs and opportunities for CO2 emission reductions. With the OKAG Plan, the resource planning function is *not* usurped by an allocation system or CO2 budget and instead remains where it belongs – "inside the fence" in the hands of state regulators with specialized expertise and a focus on ratepayer impacts and protection of

[1] *See*, https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0355-7797

> the public interest. Furthermore, the "inside the fence" model ensures that emissions reductions are limited to the engineering limits of each facility. The OKAG Plan preserves State primacy and does not turn over management of local generation fleets to EPA under the guise of "flexibility."[2]

Statutory Requirements. Section 111(d) of the CAA limits EPA's role to establishing "a procedure" for states to submit a plan for the establishment of CO_2 performance standards for existing EGUs. The Act provides that these procedures must be "similar to" those that are established for the development of state implementation plans (SIPs) under section 110. Following this model, section 111(d) provides states with primary responsibility for developing performance standards for EGUs in accordance with the "procedure" established by EPA under section 111(d).

Each state should have wide latitude to develop a plan that fits its individual circumstances and priorities. While EPA is responsible for determining the Best System of Emission Reduction (BSER) for source categories, EPA cannot dictate what a state must include or how a state must regulate sources within its jurisdiction. Rather, EPA must defer to states in determining the stringency of the state-established performance standards applicable "at" or "to" each affected EGU, as well as the timing and flexibility provided for the implementation of those standards. States have authority to establish source-specific standards based on a variety of factors, including the expected remaining useful life of the unit, unreasonable cost of control, and physical impossibility of installing emissions control equipment.

Federal-State Relationship. EPA should create a federal-state regulatory process establishing general procedures that states would follow in regulating CO_2 emissions from existing affected EGUs. These procedures would require each state to set CO_2 performance standards for each affected EGU based on the application of the BSER determination that EPA sets for each source category as well as the flexibility provided by the CAA and EPA regulations for the state to consider site-specific factors such as the remaining useful life of the source and cost factors.

In making the BSER determination for each source category, the CAA vests EPA with considerable discretion in establishing the form of the performance standards that states would apply to each affected EGU. For example, EPA could set the form of the performance standards as a range of CO_2 emissions rate limits for different types of units (most likely expressed in terms of lbs. CO_2/MWh), as a performance measure based on unit-specific historical best performance metrics, as an "operational standard"

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[2] E. Scott Pruitt, Attorney General, State of Oklahoma, "The Clean Air Act Section 111(d) Framework that Preserves States' Rights," (April 2014) at 2.

that describes the efficiency and maintenance measures (either physical or operational) that could be performed to limit CO_2 emissions from the affected unit, or some combination of these approaches.

Unit-Specific Evaluations. The procedures to be established under a replacement rule should direct each state to "kick the tires" of each particular affected EGU within its jurisdiction in order to set a standard based on site-specific factors for that unit. To assist states in setting such unit-specific performance standards, EPA should develop guidance on how states should account for variability in plant efficiency reflecting such factors as:

- **Design of Boiler** – The efficiency of the unit, for example, will vary according to the type of boiler, with supercritical steam cycles being more efficient than subcritical steam cycles. Plant efficiencies also will vary based on other factors that would need to be evaluated on a plant-specific basis.
- **Coal Burned** – Units burning bituminous coal tend to be more efficient than units burning subbituminous and lignite due to the higher heat content of the coal.
- **Size of Unit** – Plant efficiency generally increases with the size of the unit.
- **Load Level and Duty Cycle** – Units operating 24 hours per day at high capacity levels can achieve significantly higher efficiency levels than load cycling or intermediate load units.
- **Cooling System** – Once-through cooling systems typically have an efficiency advantage over recirculating systems (e.g., cooling towers).
- **Location** – The elevation and ambient temperatures at a site can influence plant efficiency.

In evaluating these and other site-specific factors, the state would identify cost-effective measures that could improve each unit's efficiency and reduce CO_2 emissions. These could include measures to restore lost efficiencies resulting from the degradation of existing components and to enhance the original design efficiency of the unit by upgrading boiler and turbine components. The CO_2 performance standard established for each unit would be deemed to meet the requirements of section 111(d).

The North Carolina Model. EPA has requested comments on a form of BSER determination whereby the agency does not set numerical limits, but focuses instead on the types of efficiency improvements that may be deemed applicable by the states on a unit-specific basis:

> The EPA also solicits comment on an approach where the EPA determines what systems may constitute BSER without defining presumptive emission limits and then allows the States to set unit-by-unit or broader emission

standards based on the identified BSER while considering the unique circumstances of the State and the EGU. 82 Fed. Reg. 61511.

The North Carolina approach cited in the ANPRM is a useful model for state unit-specific review procedures to be undertaken pursuant to a CPP replacement rule, without pre-determined numerical emission limits:

> North Carolina developed a menu of potential heat rate improvements. The State then examined these potential opportunities on a unit-by-unit basis, determined that some units had opportunities for cost-effective improvements and developed unit-specific emission standards consistent with those rates. North Carolina determined that other units did not have such opportunities (for reasons including that a given heat rate improvement opportunity was not applicable to a particular unit, that it had already been applied, or that the unit was scheduled to retire soon ... 82 Fed. Reg. 62512.

The North Carolina draft regulation offers a laundry list of potential areas to be evaluated for plant efficiency improvements:

> (2) "Air heater leakage reduction (ALR)" means to reduce air leakage between the combustion air and the exhaust gas of Lungstrom, or rotary air heaters by removal of existing air preheater seals and replacing them with newer high performance seals. ...
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> (4) "Combustion optimization with neural network (CO)" means a system that conducts real-time monitoring and controls fuel and air flow distribution, furnace exhaust gas temperatures, and boiler steam temperatures to maximize heat recovery and minimize carbon monoxide emissions and nitrogen oxides emissions. CO systems are based on nonlinear, multivariable steady-state models derived from historical unit operating data that identify the best combination of independent operating variables that produce optimum combustion and thermal efficiency with low emissions.
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> (5) "Condenser rebundle, retube, rebuild (CRR)" means to replace, repair or reconfigure tube elements, tube sheets, the condenser shell and other condenser components in order to correct leaks, plugging and debris build up to increase effective heat transfer surface area, or to otherwise improve heat transfer and fluid flow in the condenser. CRR results in greater and more consistent condenser vacuum under the range of boiler operating conditions and available cooling water temperatures.
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> (6) "Controllable loss reduction (CLR)" means developing and implementing a site-specific plan for best operations and maintenance practices (O&M) to maintain performance. CLR involves a comprehensive effort to collect

information that may not be readily collected through existing sensors and data collection systems, interpret all data collected, and make decisions regarding actions to be taken to improve or maintain performance. CLR consists of implementing a plan and instructing staff in the value and practice of collecting and reporting information regarding the ongoing performance of all the pieces of equipment comprising the power plant and implementing changes to operating or maintenance practices that are determined to improve heat rate. ...

(7) "Forced draft fan variable frequency drive (FDF)" means equipment used to reduce fan power consumption by electronically controlling combustion air flowrate. FDF utilizes a silicon controlled rectifier or equivalent device to control electrical frequency and voltage to the fan motor, thereby matching fan speed and combustion air flowrate with operating load. ...

(10) "Induced draft fan or booster fan variable frequency drive (IBD)" means equipment used to reduce fan power consumption by electronically controlling exhaust gas flowrate. IBD utilizes a silicon controlled rectifier or an equivalent device to control electrical frequency and voltage to the fan motor, thereby matching fan speed and exhaust gas flowrate with operating load.

(11) "Intelligent soot blowing (ISB)" means the use of software, instrumentation, sensors, and automated controls to achieve more effective cleaning of furnace wall and convective section heat transfer surfaces. The ISB system may consist of devices for monitoring furnace exhaust gas temperatures, steam temperatures, and furnace wall temperatures at different locations, a control system, and furnace cleaning devices. The ISB's control system digitally processes the received information to evaluate the effects of real-time heat transfer performance in order to allocate high pressure steam or high pressure air to cleaning devices in specified heat transfer zones. The ISB activates furnace cleaning devices (also known as "soot blowers") when measurement sensors indicate the need to remove ash or slag deposits from the furnace location where it is most effective to do so, resulting in improved boiler efficiency as well as reduced energy demand from soot blower and furnace cleaning systems. ...

(17) "Variable speed drives" means a system to increase and decrease the operating speed of fluid moving equipment such as fans or pumps by reducing the drives' rotational speed in revolutions per minute to meet required changes in fluid flow rates."[3]

[3] *See*, https://files.nc.gov/ncdeq/Air%20Quality/rules/hearing/111dRules.pdf

The unit-specific analyses called for by the North Carolina draft regulation are consistent with the approach to 111(d) regulation described by Administrator Pruitt's April 2014 OKAG paper:

> Specifically with regard to coal plants, States and EPA have limited options in determining systems of CO2 emission reduction that have been adequately demonstrated as achievable. EPA itself has acknowledged on several occasions that CCS would not qualify as a performance standard for existing coal plants. The only way to achieve cost-effective emission reductions for a coal generator would be to improve the efficiency of the unit, since increased efficiency translates into reduced CO2 emissions per unit of electric output. <u>Existing coal plants differ widely in terms of the combustion technologies they use, their ages, maintenance histories, and how they operate. There is no "one-size-fits-all" method of improving unit efficiency that would apply to all units in the coal fleet. As a result, CO2 performance standards must be based on unit-by-unit evaluations of available cost-effective efficiency.</u> This approach, which is grounded squarely in the language and history of the Section 111 program, would not require coal plants to retire or curtail operation; they would only require more efficient operation, to the extent it is cost-effective to do so.[4]

Subcategorization and BSER Issues. We conducted a statistical analysis of CO_2 emissions from coal plants using the DOE/NETL 2007 coal plant data base. The purpose of this exercise was to assess whether plants burning different grades of coal (bituminous, subbituminous, and lignite) have sufficiently different CO_2 emission rates to consider subcategorization by coal type in any determination of a BSER. State targets established under the CPP did not consider the differences in CO2 emission rates among coal types.

We sorted the NETL data base to identify coal-based units most likely to remain in operation after implementation of the 2012 EPA Mercury and Air Toxics Standards (MATS) rule, using three screening criteria: unit nameplate capacity of 400 MW or greater, current age of 50 years or less, and heat rate of 9,000 BTU/kWh or higher (typical of conventional PC-based units.)

This sort produced 272 coal-based units, totaling 176,700 MW of capacity, with the following performance data:

[4] E. Scott Pruitt, *supra,* n. 2 at 7-8 (emphasis added).

Summary Statistics of 272 Coal Units >400 MW, Age 50 or Less, with Heat Rates >9,000 BTU/kWh, By Coal Type

				PCT DIFF VS 272 UNIT MEAN	
	BTU/KWH	LBS CO2/MWH		BTU/KWH	LBS CO2/MWH
ALL 272 UNITS					
AVG	10,240	2,148		NA	NA
STD DEV	658	202			
BIT 141 UNITS (94,039 MW)					
AVG	9,987	2,055		-2%	-4%
STD DEV	471	175			
SUBBIT 110 UNITS (69,500 MW)					
AVG	10,472	2,214		2%	3%
STD DEV	695	164			
LIGNITE 21 UNITS (13,140 MW)					
AVG	10,957	2,425		7%	13%
STD DEV	509	150			

Emission rate differences among the three coal types measured in average CO2 emission rates per MWh could support subcategorization by coal type, particularly for low-BTU lignite coals. The 21 sampled lignite units have an average CO_2 emission rate 13% above the sample mean. Bituminous coal-based units have an average emission rate 4% below the sample mean, while subbituminous units are 3% above the mean.

Presumptive Limit Issues. These subcategorization data also underscore the variability in CO_2 emissions performance among the three coal categories. The standard deviation of CO_2/MHw for the 272 unit sample is 202 compared with a sample mean of 2,148 lbs. CO_2/MWh, or nearly 10%. The relatively large standard deviations among all three coal types suggest that setting a BSER with a quantified emission limit or range of limits for subcategorized groups of sources may severely penalize some units with relatively high emission rates, reflecting variables such as age, pollution controls in place, etc. In addition, the dynamic changes in dispatch for coal-based units associated with inter-fuel generation cost differentials could render any quantified emission limit or range of limits obsolete over time.

The ANPRM effectively recognizes the practical limitations of a presumptive emission limit in any BSER determination applicable to groups of sources:

> (W)ith regard to coal-fired EGUs, the potential for emission reductions at the unit-level or source level may vary widely from unit to unit. Consequently, broadly applicable, presumptively approvable emission limitations (even at a subcategorized level) may not be appropriate for GHG emissions from EGUs. Therefore, in this ANPRM, the EPA is taking comment on an approach where the Agency defines BSER or otherwise provides emission guidelines without providing a presumptively approvable emission limitation. 82 Fed. Reg. 61513.

The emissions variability evident in our sample of 272 units could lend support to a presumptively approvable numerical BSER based on a unit- or plant-specific historical "best performance" measure, with emission reduction methods needed to achieve and maintain such a limit determined by the states or by unit owners in the context of state procedures to implement EPA's guidelines. Such an approach would lend certainty to the emission reductions needed to achieve and maintain an EPA-determined BSER, while reducing the risk of litigation associated with the determination of appropriate unit- or plant-specific mitigation measures.

The ANPRM lists (in Tables 1 and 2) a variety of measures that can be applied at individual units to improve heat rate and reduce emissions. These potential measures are more extensive than those considered in the North Carolina draft regulations, and could provide the bases for an indicative roster of equipment and work practice improvements that states or unit owners should consider in developing plans to comply with EPA guidelines.

The extensive nature of the potential equipment and work practice measures enumerated in the ANPRM casts doubt upon the agency's prior efforts to estimate heat rate improvements on a regional basis, in the absence of unit-specific assessments.[5] These regional assessments formed the bases for Building Block 1 of the CPP. We respectfully submit that any accurate assessment of potential heat rate improvements and emissions reductions associated with equipment and work practice measures such as those identified

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[5] "The EPA has previously assessed the potential heat rate improvements of existing coal-fired EGUs by conducting statistical analyses using historical gross heat rate data from 2002 to 2012 for 884 coal-fired EGUs that reported both heat input and gross electricity output to the Agency in 2012. The Agency grouped the EGUs by regional interconnections— Western, Texas, and Eastern—and analyzed potential heat rate improvements within each interconnection. The results of the statistical analyses indicated that there may be significant potential for heat rate improvement—both regionally and nationally. However, these results represent fleet-wide average heat rate improvement. The EPA did not conduct analyses to identify heat rate improvement opportunities at the unit level, and the Agency recognizes that the fleet of U.S. fossil fuel-fired EGUs is varied in terms of size, age, fuel type, fuel usage (*e.g.* baseload, cycling, etc.) boiler type, *etc.*" 82 Fed. Reg. 61,513.

in Tables 1 and 2 of the ANPRM requires individual unit assessments, taking into account the flexibility measures provided by section 111 and its implementing regulations.

No Redefinition of the Source. Any BSER definition in a replacement rule should explicitly guard against "redefinition of the source" through measures such as natural gas cofiring or conversion. The emission controls to be applied "to" or "at" an individual source should be limited to those measures - such as those identified in the North Carolina rule and in Tables 1 and 2 of the ANPRM - that will improve unit efficiency and reduce CO_2 emission rates while maintaining the essential character of the source.[6]

Limits on Emissions Trading. EPA requests comment on emissions trading and on whether a replacement rule should be based on emission rate or on mass-based limits:

> The Agency's existing CAA section 111 rules (both new-source rules under 111(b) and existing-source rules under 111(d)) are all based on emission rate standards (*e.g.,* mass of pollutant per unit of heat input or production). The potential opportunities for improvements in a unit's GHG performance seem similarly amenable to emission rate standards. The EPA requests comment on whether emission guidelines for GHG emission rate standards is all that it or the States should consider in a potential future rulemaking or whether the use of mass-based emission standards should also be considered. 82 Fed. Reg. 61,512.

Given the Administrator's emphasis on controls that can be applied "to" or "at" an individual source,[7] we agree that an emission rate limit is the appropriate metric for states to use when applying EPA's guidelines. While UJEP members traditionally support mass-based programs to facilitate cost-effective emissions trading among sources, the use of emission trading in this rule should be extremely limited, such as through Plantwide Applicability Limits (PALs) or similar "inside the fence" emission rate averaging approaches. Emissions trading "outside the fence" appears to be inconsistent

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[6] For a discussion of issues associated with redefining the source in case-by-base BACT reviews for new and modified sources, *see, e.g.*, EPA, PSD and Title V Permitting Guidance for Greenhouse Gases (November 2010) at 28-29 and cases cited therein. EPA generally has not supported changes to the design of new or modified sources that would fundamentally alter the nature or business purpose of the source.

[7] *See*, 82 Fed. Reg. 48,037 (October 16, 2017): Here, contrary to the conclusion in the CPP, the EPA is proposing to interpret the phrase "through the application of the best system of emission reduction" as requiring that the BSER be something that can be *applied to* or *at* the source and not something that the source's owner or operator can implement *on behalf of* the source at another location. Interpreting the statute as carrying this additional limiting principle ensures conformity with the statutory context and congressional intent.

with prior agency rulemakings under section 111(d).[8]

Administrator Pruitt also cautioned against the use of mass-based emission trading schemes in his April 2014 paper outlining Oklahoma's views on 111(d) regulation:

> The OKAG Plan offers an alternative framework that is consistent with the State primacy entrenched in Section 111(d). As contemplated by Section 111(d), States possess the authority and discretion to define emission reduction requirements through unit-specific analyses. The OKAG Plan eschews the mass-emissions model because this approach subsumes resource planning processes traditionally left to the States into mandatory CO2 budgets. Instead, the OKAG Plan allows for a unit-by-unit analysis and considers affordable electricity.[9]

We recommend that EPA defer to the states issues about potential rate-based emissions trading or averaging as a compliance flexibility measure under a replacement rule. EPA should establish a separate rulemaking docket - or issue appropriate guidance - to examine the appropriateness of trading programs, and the mechanisms that might be developed to facilitate such programs. This separate docket or guidance could address the questions posed by the ANPRM[10] on "outside-the-fence" trading and averaging. Given the lack of express authority in section 111(d) for emissions trading, the CPP replacement rule should avoid the "outside the fence" aspects of the original CPP rule that raised the most serious legal questions about the underlying validity of the rule.[11]

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[8] *See, id.*, at 48,041: Indeed, the EPA has issued numerous rules under CAA section 111 (both the limited set of existing source rules under CAA section 111(d) and the much larger set of new source rules under CAA section 111(b)). All those rules limited their BSER to physical or operational measures taken at and applicable to individual sources, with only one exception—a rule that was vacated by the D.C. Circuit on other grounds.

[9] E. Scott Pruitt, *supra*, n. 2 at 5.

[10] "Should States be able to develop plans that allow emissions averaging? If so, should averaging be limited to units within a single facility, to units within a State, to units within an operating company, or beyond the State or company? If averaging is not limited between units in different States or between units owned by the same company, are any special requirements needed to facilitate such trading? Should mass-based trading be considered? If so, how should rate-based compliance instruments intended to meet unit-specific emission rates be translated into mass-based compliance instruments? Should rate-based trading programs be able to interact with mass based trading programs? What considerations should States and the EPA take into account when determining appropriate implementing and enforcing measures for emission standards? The EPA requests information and feedback on all of these questions and on what limitations, if any, apply to States as they set standards." 82 Fed. Reg. 61,512.

[11] *See*, 82 Fed. Reg. 48042: (R)ecognizing "the long history of trading" under title IV and CAA section 110(a)(2)(D)(i)(I) to demonstrate the 'achievability" of the "performance rates" in the CPP does not clarify the interpretive question the Agency faces under CAA section 111(a)(1)—

Option for Periodic Updating of Emission Rate Standards. Section 111(d), unlike New Source Performance Standards established under section 111(b), is a one-time process for setting emission limitations for existing sources. NSPS are routinely reviewed and updated as appropriate by EPA on an 8-year schedule, ensuring that the most recent control technology and methods are applied to new sources.

EPA should consider adding optional provisions in a replacement rule for states to periodically review and update unit-specific emission rate standards to reflect changes in available equipment and work practices for improving unit efficiency, as well as market-related and other factors influencing unit performance. The advent of an "inside the fence" replacement rule could be expected to promote innovative technologies to improve power plant efficiencies, just as previous EPA rules (e.g., Title IV acid rain control, NOx SIP Call) led to major improvements in control technologies for sulfur and nitrogen oxides.

In the 1998 NOx SIP Call, EPA provided states with an optional periodic updating methodology for allocation emission allowances to affected sources.[12] The agency's model trading rule initially was limited to a heat-input based updating methodology because EPA lacked sufficient data to develop an output-based method, recognized at the time as more likely to accurately reflect future changes in control technologies and other factors:

> (T)oday's Model Rule includes an optional allocation methodology. The Agency has carefully considered arguments for alternative allocation methods. The EPA would support a decision by a State to use either heat input or output data as a basis for source allocations or for the State to auction some or all of its allocation. In determining the basis for the methodology presented in today's Model Rule, EPA has decided to use the heat input approach because it is concerned that an output-based approach has not been fully developed or made available for public comment. ...
>
> The Agency recognizes that a State's choice of when and for what blocks of time it issues allocations is intertwined with the choice of allocation methodology. Several commenters suggested that more incentives for generation efficiency and therefore ancillary environmental benefits (CO2 and mercury reductions) are provided in an output system with periodic

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i.e., what is the "best system of emission reduction" that can be applied to an affected source? To the contrary, Congress expressly established the cap-and-trade program under title IV, 42 U.S.C. 7651–7651o, and expressly authorized the use of "marketable permits" to implement ambient air quality standards under CAA section 110, *id.* at § 7410(a)(2)(A). We think it unlikely that Congress would have silently authorized the Agency to point to trading in order to justify generation shifting as a "system of emission reduction."

[12] *See*, 63 Fed. Reg. 57,356 (October 27, 1998) at 57,470-57,471.

updates, and those incentives are lost in an heat input system that is periodically updated.[13]

While we do not advocate that the CPP replacement rule contain any form of "outside the fence" emissions trading program, for the reasons discussed above, the considerations supporting an updating output-based performance standard for state allowance allocations in the NOx SIP Call appear to be applicable to state emission rate standards made under a section 111(d) rulemaking. The same type of voluntary, optional approach for updating standards used in the SIP Call could be developed for states to consider in their plans for implementing EPA's replacement rule, such as periodically revisiting and updating equipment and work practice standards deemed appropriate for individual EGUs. This would provide the program with a forward-looking approach that could take advantage of future advances in technologies, engineering practices, etc., that may improve unit efficiency and reduce emissions. Similar considerations would support an updating mechanism in the event that BSER is determined based on a unit's historic "best performance" metrics.

NSR Issues

The ANPRM raises several issues concerning the New Source Review program and its relationship to a replacement rule for the CPP. We understand that the agency will be pursuing a public process later this year concerning potential reforms to the NSR program, which could complement the energy efficiency improvement goals of a replacement rule.

Carbon dioxide and other air emissions can be cost-effectively reduced in significant amounts by improving the generating efficiency of existing fossil fueled power plants. However, EPA’s NSR permit program has become a major impediment to the implementation of many efficiency improvement projects at existing power plants. Similarly, the NSR program can also deter major maintenance projects that may be necessary for ensuring the reliability and safety of existing power plants.

We recognize the improvements to NSR already underway at EPA, such as the Administrator's December 7, 2017, memorandum[14] addressing the agency's prospective position on the use of actual-to-projected modeling in NSR applicability determinations. This is an important step forward in clarifying EPA procedures in determining NSR

[13] 63 Fed. Reg. 57,470.
[14] Memorandum from Administrator E. Scott Pruitt, "New Source Review Preconstruction Review Permitting Requirements: Enforceability and Use of the Actual-to-Projected-Actual Applicability Test in Determining Major Modification Applicability," December 7, 2017.

applicability, and will be followed by further regulatory improvements consistent with the President's memorandum of January 24, 2017, on Streamlining Permitting and Reducing Regulatory Burdens for Domestic Manufacturing, as well as Executive Order 13777 on Enforcing the Regulatory Reform Agenda (February 24, 2017).

NSR Modification Rules. Current federal NSR regulations establish a two-part test for determining whether plant modifications trigger NSR review. First, there must be a physical change or change in the method of operation at an existing major stationary source that is not categorically exempted by regulation from NSR review. Notable examples of such categorical NSR exemptions include "routine maintenance, repair and replacement" projects and increases in hours of operation or rate of production at existing sources. Second, the non-exempted physical or operational change must result in a "significant net emissions increase" above the unit's baseline actual annual emissions levels for any particular regulated air pollutant. The current NSR regulations and EPA guidance establish complicated rules for projecting an existing source's future annual emissions.

Requirements for Issuance of NSR Permits. The NSR regulations impose onerous permitting requirements on any existing power plant that makes a modification that triggers the NSR permitting requirements. Those requirements include the following:

- *An obligation to install the most advanced pollution control technologies that are currently available and meet the most stringent emission rate limits that can be feasibly achieved.*[15] For example, the NSR technology requirement has the effect of requiring coal-fired power plants to install a scrubber to control their SO_2 emissions, selective catalytic reduction systems to control their NO_x emissions, and a baghouse to control particulate emissions. While the vast majority of coal-fired units employ advanced emission controls for one or more pollutants, relatively few plants employ state-of-the-art controls for <u>all</u> pollutants regulated under the Clean Air Act.
- *Requirements to ensure the protection of air quality.* One key permit requirement for "attainment" areas – those areas meeting national ambient air quality standards (NAAQS) – is the performance of extensive air quality modeling to demonstrate that the increased emissions from the modified plant will not cause or contribute to violation of a NAAQS, nor significantly degrade air quality

[15] Specifically, sources must install pollution control technologies meeting "best available control technology" (BACT) for those air pollutants meeting air quality standards and therefore subject to PSD permit review in attainment areas. Similarly, for those air pollutants subject to nonattainment-NSR review, sources must install control technologies that achieve emissions reductions to the greatest extent possible, referred to as "the lowest achievable emissions rate" (LAER).

in attainment areas.[16] If modeling indicates that any of these adverse air quality impacts could potentially result from the modified source, then various types of mitigation would be necessary before the plant owner or operator may undertake the modification.[17]

- *Obtaining emission offsets for nonattainment areas*. In the case of modified plants located in areas not meeting a NAAQS (referred to as nonattainment areas), one key nonattainment-NSR requirement is for the plant to obtain emissions offsets on at least a one-to-one basis and to demonstrate that there will be reasonable further progress toward achievement of the NAAQS for any nonattainment air pollutant.
- *Completing extensive public notice and comment process on the NSR permit.* These requirements require the permitting authority to provide an opportunity for public comment on the draft NSR permit, hold public hearings on that draft permit, and provide a detailed response to each comment received during the public comment period. These public notice and comment procedures have taken multiple years to complete in the case of controversial projects, such as the construction of new coal-fired power plants or other major energy infrastructure projects.

The Deterrent Effect of the NSR Permit Program. The stringency of the NSR permit requirements has the effect of deterring many owners and operators of existing sources from implementing energy efficiency improvements or other major reliability or safety projects that might trigger the onerous requirements under the NSR permit program. If, for example, a project undertaken at an existing plant is deemed to be a "modification" that triggers NSR review, the plant must install the most advanced pollution control technologies that are currently available and impose the most stringent emission rate limits that can be feasibly achieved. The NSR technology requirement has the effect of requiring coal-fired power plants not already equipped with these technologies to install scrubbers to control SO_2 emissions and selective catalytic reduction systems to control NO_x emissions. The capital costs of these retrofits are typically in the hundreds of millions of dollars for a typical 500 MW unit.

Unfortunately, despite years of litigation and multiple regulatory reform initiatives, considerable uncertainty still remains as to whether physical or operational changes at existing major stationary sources would be a "modification" that are subject to the

[16] Another air quality requirement is the performance of modeling that demonstrates that the source's increased emissions will not adversely impact visibility or other "air quality related values" in a PSD Class I national park or wilderness area.

[17] This mitigation could involve the permit authority requiring the source to achieve more stringent emission controls or obtain offsetting emission reductions from other sources in the same air shed (emissions offsets, typically on a ratio of at least 1.3:1).

onerous NSR permitting requirements. EPA, for example, has taken the position that many types of energy efficiency improvements that could be undertaken at existing power plants may be non-routine and could potentially cause significant increases in annual emissions that triggers NSR review. Furthermore, courts have been unable to resolve this uncertainty and provide clear guidance on what a non-routine change is and how to determine whether the non-routine change might cause a significant annual emission increase.

This uncertainty has adverse competitive and economic repercussions for U.S. industry and American workers by creating a strong disincentive to undertake projects that can improve the efficiency and productivity of our existing plants. In the case of coal-fired power plants, the disincentive to undertake such projects results from the significant regulatory consequences of triggering NSR review. These consequences include lengthy permitting delays, potential enforcement actions, and incurring large capital retrofit costs for SO_2 scrubbers and NO_x SCR systems. This uncertainty creates a strong disincentive to undertake efficiency projects that can cost-effectively reduce CO_2 and other air emissions from the existing fleet of plants.

Many types of major efficiency improvement projects at existing coal-fired power plants, such as boiler and generator upgrades, could greatly reduce CO_2 emissions because less coal would be used to produce each kilowatt-hour of electricity. In addition to efficiency upgrades of existing steam turbine components, other types of efficiency improvement projects currently available for coal-fired power plants include the installation of more efficient auxiliary equipment drive motors and replacement of degraded boiler components.

OPTIONS FOR FIXING THE NSR PROBLEM. Over the years, EPA has used its authority under the Clean Air Act to adopt new regulations on the types of projects undertaken at existing power plants that do not trigger NSR review. For example, EPA could revise the emissions increase test that is used for determining whether a non-routine change results in an emissions increase that triggers NSR review. For another example, EPA could adopt a simpler emissions increase test based on the "maximum hourly emissions," the test already used by EPA for determining applicability under the New Source Performance Standards (NSPS) program. The NSPS maximum hourly emissions test compares (1) the maximum hourly emissions achievable at the power plant unit in the five years prior to the project with (2) the maximum hourly emissions achievable after the project.[18] In this way, a non-routine change would not be determined to cause an emissions increase unless maximum achievable hourly emissions increase due

[18] *See* 40 C.F.R. §60.14(a), (b), and (h).

to the change.[19]

A similar revision to NSR emissions increase was considered by the Bush Administration, but were never finalized. The Bush Administration proposal would have established a two-step process for determining whether a non-excluded physical or operational change resulted in an emission increase triggering NSR review. First, there must be an increase in the achievable hourly emission rate at the particular unit undergoing a physical or operational change, and second, there must be a significant net emission increase in annual emissions across the entire facility. This approach also appears to have merit and therefore should be re-evaluated by EPA.

Safe Harbor from NSR Review. To maximize the CO_2 reductions that could be achieved under the CPP replacement rule, EPA should pursue a parallel rulemaking to revise current NSR regulations that deter electric utilities from undertaking many types of efficiency improvement projects. Revised NSR requirements in turn could be reflected in the unit-by-unit assessments to be undertaken by states.

EPA's procedures should specify that NSR review is not triggered by energy efficiency measures that the state identifies in its plan as the basis for setting CO_2 performance standards. Stated differently, states should not require unit owners to make efficiency improvements that would trigger NSR. NSR thus would set a cap on the level of efficiency improvements that may be required through the state review process.

Finally, the CPP replacement rule should establish procedures that would allow states to adjust the CO_2 performance standard for a particular unit to reflect an agency or court determination that a particular type of efficiency measure used for setting that performance standard is not a change that is excluded from NSR review. In such cases, the procedures would authorize states to take into account the additional costs that would result from particular efficiency projects triggering NSR and therefore provide the technical basis for the disqualification of those projects in setting the performance standards for particular EGUs.

EPA Approval of State Plans. EPA's procedures should delineate the limited role that EPA has in the review and approval of state plans. EPA would approve each state plan to the extent the state adhered to the procedures outlined above for setting the CO_2 performance standards for each unit on a case-by-case basis.

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[19] Another possible administrative reform could involve the adoption of NSR exclusions for efficiency, reliability and safety improvement projects. While there appears to be a statutory basis for establishing such exclusions, the D.C. Circuit has adopted a very narrow interpretation on the types of projects that can be excluded from NSR review.

We will appreciate EPA's consideration of these comments.

Sincerely,

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cc: Members of Congress
Richard L. Trumka